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TRANSMITTAL LETTER

To: Ms. Teresa Heron
New Source Review Section
FDEP, Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399

Date: June 10, 2002
Project No.: 0137609-3103

Sent by: ARZ

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Per: Kennard F. Kosky, P.E.

Quantity	Item	Description
1 Set	**3 Volumes and Sufficiency Responses**	*Site Certification Application and Sufficiency Responses for FPL Manatee Expansion Project, Manatee County, Florida*

Enclosure

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BUREAU OF AIR REGULATION

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Golder Associates

June 7, 2002

0137609

Ms. Teresa Heron
New Source Review Section
Bureau of Air regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

RECEIVED

JUN 10 2002

BUREAU OF AIR REGULATION

RE: FPL MANATEE EXPANSION PROJECT
Request for Additional Information
Project No. 0810010-006-AC (PSD-FL-328)

Dear Teresa:

On behalf of Mr. Simmons of Florida Power & Light Company, I am submitting the enclosed responses to the comments and questions contained in your April 5, 2002 memorandum to Mr. Oven concerning the Air Permit and Prevention of Significant Deterioration (PSD) Application for the FPL Manatee Expansion Project. The responses to your comments and questions have also been included in the sufficiency responses submitted to Mr. Over as part of the Site Certification proceedings.

We trust this responds fully to all of your comments and questions. Please contact either Mr. Simmons, the FPL application contact [phone (561) 691-2216], or myself if we may be of further assistance.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal

KFK/lsh

Enclosures: 4 copies

cc: Paul Plotkin, Plant General Manager Manatee Plant
K. H. Simmons, Manager of New Capacity Projects

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Manatee Expansion Project
Additional Information-Florida Department of Environmental Protection
Bureau of Air Regulation
DEP File 0810010-006-AC (PDS-FL-328)

Comment 1FDEP-1: Minor Sources: "The application only lists the combustion turbines (CT), heat recovery steam generator (HRSG) and fuel heaters (FH). What will be the auxiliary equipment for this project (i.e., cooling tower, fire pump)? Submit emissions estimates for these minor sources and include these emissions as part of the PSD applicability review."

Response: There will be no other auxiliary equipment or minor sources of air pollution associated with the Manatee Unit 3 project. The emission units identified in the Air Permit/PSD Application are the only emission units associated with the project. These are the four combustion turbines, the four HRSG duct burner systems and 4 natural gas fuel heaters. There will be no cooling tower(s) or diesel fire pumps associated with the project.

Comment 1FDEP-2: Natural Gas and Sulfur Dioxide Emissions: "Please revise and submit sulfur dioxide emissions. Proposed sulfur dioxide emissions are calculated based on an emission factor of 2 grains sulfur/100 scf pipeline natural gas. Recent BACT determinations have considered an emission factor of not more than 1.5 grains sulfur/100 scf. When would the gas supplier be selected?"

Response: The sulfur content in pipeline natural gas is controlled by the supplier. It is a function of the amount of sulfur remaining from the removal mechanisms during processing (e.g., Claus process for H_2S removal) and the amount of mercaptans added as an odorant. The only requirement for total sulfur for pipeline natural gas is the Federal Energy Regulatory Commission (FERC) limit of 20 grains per 100 standard cubic feet (scf). Typically, the total sulfur in pipeline natural gas is less than 1 grain/100 scf but is variable. For the Manatee Unit 3 Project, an SO_2 emission rate based on 2 grains/100 scf was used as a conservative upper limit to account for variability and the ultimate natural gas supplier. However, the total sulfur assumed in the Air Permit/PSD Application is 10 times lower than the FERC requirement. The gas supplier(s) will be selected prior to the operation of the unit.

Comment 1FDEP-3: Heat Recovery Steam Generator: "What is the maximum steam production rate (lb steam/hr) from each HRSG? What is the capacity (MW) of the steam generator? What is the model and manufacturer of the duct burners and HRSG, if already selected? Submit the manufacturer performance emissions data sheets if available. Provide supporting documents and/or calculations of the expected emissions levels for the combined gas turbine exhaust and the duct burner emissions."

Response: The steam production of the HRSG will vary depending upon ambient temperature conditions and the amount of duct firing. Under maximum duct firing (550 MMBtu/hr) the maximum amount of steam produced is about 750,000 lb/hr. Under normal duct firing (about 200 MMBtu/hr) the amount of steam produced is about 575,000 lb/hr while without duct firing the amount of steam produced is about 425,000 lb/hr. The capacity of the steam turbine generator is a 460 MW (nominal). The manufacturers for the duct burners and HRSG have not been selected. The duct burner emissions presented in the application have been guaranteed on other similar projects. Attachment A presents typical information from a typical duct burner manufacturer. Attachment B contains performance data for the GE Frame 7FA combustion turbine for Martin Units 8A and 8B. The CTs planned for the Manatee Unit 3 project will be similar to those for the Martin Unit 8 Project. Attachment C presents duct burner calculations. Emission calculations for the combustion turbine and combustion turbine with duct firing are contained in Appendix A of the Air Permit Application and PSD Analysis (Appendix 10.1.5 of the SCA).

Comment 1FDEP-4: High Power Modes of Operation: "Please expand details of the operations (temperature, % load, power output) under the requested modes of power augmentation, fogging, and peak. What is the manufacturer's maximum recommended period (hr/yr, hr/month) for operation under each of these modes?"

Response: Table 1FDEP-4 presents a matrix for the operation of Martin Unit 3. Descriptions of fogging, power augmentation and peak operation follow.

Use of Inlet Fogging

The inlet cooling fogging systems can be used under all operating modes as long as the ambient conditions are appropriate for reducing the inlet temperature using the system. This occurs when the ambient temperature is greater than 60°F. The amount of heat removed using inlet-fogging systems is highly dependent upon the ambient air conditions. The two most important parameters are the dry bulb temperature and relative humidity. As moisture is added to the inlet air by the fogging, the vaporization of the fog droplets cools the air toward the wet-bulb temperature. For example, at an ambient temperature condition of 95°F and 50 percent relative humidity the resultant wet bulb temperature, based on psychometric charts is 79°F. At 100-percent saturation the inlet cooling system would result in a 16°F decrease of the turbine inlet air.

In Florida adiabatic cooling can be an effective means of inlet air cooling during the late morning to evening hours. This period is typically 8 to 10 hours per day from about 10 am to 8 PM. In the early morning hours and evening hours, the typical relatively humidity in Florida is 70 to 90 percent depending on the climatic conditions and is generally unfavorable for inlet cooling.

The typical mid-afternoon cooling during the summer would be about 11°F and occurs with a mid-afternoon temperature of 90°F and 64 percent relative humidity. In contrast, the average minimum temperatures during winter and spring range from about 55°F to 65°F with relative humidity of about 80 percent. The amount of adiabatic cooling would be about 3 to 4°F and is generally unfavorable for inlet cooling.

The effect of decreasing the turbine inlet air through the use of fogging will be to increase the mass flow of air that can go through the turbine which allows higher heat input and power output. The combustion turbine is also more efficient since the heat rate decreases with decreasing temperature. However, the turbine is still operating on its original power curves. Therefore, the performance does not change from what would normally occur at that temperature and relative humidity. In addition, there is no change in the emission rates when inlet cooling. There is no limitation on the use of inlet fogging other than having the appropriate ambient air conditions for its use.

Power Augmentation and Peak

Power augmentation involves the injection of steam to increase power. It is only operated when the combustion turbine is operated at base (100 percent) and when the turbine inlet temperatures are 59°F and above.

Peak mode involves increasing the firing temperature of the combustion turbine to increase power output. This is accomplished through the digital control system. Peak operation would only occur at base load (100 percent).

Power augmentation and peak operation have been termed "higher power modes" in the application. There is no specific manufacturer limitation on the number of hours (i.e., hours/year or hours/month) for power augmentation or peak operation other than performing the required maintenance requirements specified by GE for each operating mode. When operating in these modes, the duration between maintenance periods are significantly decreased. The requested number of hours in the application limits the operation of these modes to within acceptable maintenance requirements of GE.

Comment 1FDEP-5: Automated Control System: "What type of control system is recommended by the combustion manufacturer (i.e., Mark V control system, etc)."

Response: The GE Frame 7FA combustion turbine uses the GE SPEEDTRONIC™ Mark VI control system. The main functions of the Mark VI control system are the control during startup, automatic generator synchronization, and turbine load control during normal operation and protection against turbine damage. The system also controls the operation of the Dry Low NO_x 2.6 (DLN 2.6) system. The system is fully automated with sequencing of the combustion system through a number of staging modes prior to full load.

Comment 1FDEP-6: Start Up and Shutdown Emissions: "Please submit a Best Operating Practice procedure for minimizing emissions during start up and shutdown (cold, warm, hot, simple cycle, and combined cycle). What is the proposed number of startup/shutdowns? Estimate the pollutants emissions during this period. Describe the "steam blow" process and explain the requested length of time (90 days). Please provide supporting documentation."

Response: As described in the response to the preceding comment, the startup and shutdown of the unit will be automated and will be designed to minimize emissions consistent with manufacturers recommendations. The submittal of a Best Operating Practice procedure is somewhat premature since several of the control systems have not yet been selected (e.g., the SCR vendor). While these procedures will be submitted as part of the Title V application, the discussion below presents a discussion of startup and shutdown.

Startup and Shutdown

In simple cycle operation, the CTs meet the proposed emission limits within about 30 minutes. In combined cycle, the startup of the combustion turbine involves controlling the exhaust temperature and flow, so as not to exceed limitations imposed by the HRSG manufacturer regarding rate of change of metal temperature and change of metal temperature differentials. These limitations are reflected in maximum allowed increasing and decreasing HRSG ramp rates, and specified steam drum temperatures/pressures and duration.

The limitations result in the need for a relatively long startup time for the CT when the HRSG is cold. If the plant has been operating, and is then shutdown for more than 48 hours, the HRSG is considered to be cold. Then a 4-hour HRSG startup duration is required before the CT can be operated at loads above 50 percent load when firing natural gas.

If the plant shut down is less than 48 hours, then the HRSG is considered to be warm, and a 2-hour HRSG startup duration is required before the CT can be operated at above 50-percent load when firing natural gas.

Similar startup limitations, imposed by the steam turbine manufacturer are designed into the turbine control system, and will apply when starting the steam turbine for combined cycle operation.

These limitations result in a total duration of 12 hours where loads of 50 percent will occur for the CTs. The CTs are started in sequence and the conditions of cold and warm startup would apply.

The startup will vary by the equipment vendors but presented below is a typical description of the process. During all startup conditions, the speed and load of the combustion turbines (CTs) are regulated to provide conditions that would not damage the HRSGs or steam turbine. The typical conditions described below.

1. Cold Start – Occurs when the combined cycle unit has been shutdown for more than 48 hours. The total time for this startup condition is 12 hours. The first CT is started and held at certain levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 2-hours into the start and load is applied to the CT at about 3 hours into the start. The second CT is started about 3 to 4 hours into the start with load applied at about 4 to 5 hours into the start. The third and fourth CTs are started in a similar sequence. At 12 hours into the start, all CTs are at a load that will comply with proposed emission limits.
2. Warm Start – Occurs when the combined cycle unit has been shutdown for 48 hours or less. The total time for this startup condition is about 2 hours. Similar to the cold start, the first CT is started and held at levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 1 hour into the start and load is applied to the CT shortly thereafter. The second CT is started about 1 hour into the start with load applied at about 1½ hours into the start. At two hours into the start, the first CT has reach full load with steam applied to the steam turbine. The other turbines are started in similar sequence.

Section 2.5.2 of the Air Permit/PSD Application (Appendix 10.1.5 of the SCA) proposed a condition for cold startup of Unit 3 that was identical to that previously approved by the department for the FPL Fort Myers Repowering Project. A maximum number of startups/shutdowns cannot be proposed for the Project. The number of unit startups per year will vary depending on unit dispatching maintenance requirements, forced outages, and other system factors. The units are expected to operate as base load units. Typical maintenance requirements would require about one cold startup/shutdown per year.

Emissions in excess of the proposed emission limits will be for the pollutants scheduled and NO_x, CO, and VOC. Emissions of PM and SO_2 are governed by primarily fuel quality. During steam blows, the CTs are operated at about 12 MW, which is about 7-percent load. Based on GE estimates, the NO_x emissions will be from 70 to 80 ppmvd corrected to 15-percent O_2. These emission rates will exceed the emission rates at 50-percent load and above. In addition, the SCR will not yet be operational for steam blows and the operating temperature will not be sufficient. For CO and VOC the estimated emissions will be 100 ppmvd and 7 ppmvw, respectively.

During cold and warm starts the NO_x emissions will vary between about 60 and 100 ppmvd corrected to 15-percent O_2. For CO, emissions will be highly variable any range between 20 and 1,000 ppmvd. Similarly, VOCs will vary between less than 2 ppmvd and 100 ppmvd. Operating during these periods is of short duration and at operating conditions where mass emissions (lb/hr) are concommitally lower due to lower mass flow through the turbine.

Steam Blows

During construction, the steam piping systems internally accumulate weld spatter, slag, filings, and other debris. If this material is not removed prior to steam turbine operation, the steam turbine will be damaged by the metal particles, which would strike the blades and steam path vaning at very high velocities. Blowing through the piping system with steam removes this material, along with rust, grease, and other fabrication and construction residues prior to commencement of combined cycle operation.

The steam blow procedure involves firing the combustion turbine (CT) in order to generate steam in the heat recovery steam generator (HRSG), and then passing the steam through the piping towards the steam turbine. A temporary tee is installed in the steam line to divert the steam and foreign matter, to the atmosphere. Initial "steam blowing" is performed until the exhaust has no color, and then a polished target is inserted near the venting location, prior to subsequent blows. Blowing of steam through the line continues until the target shows limited "hits", according to established criteria. When this criteria has been met, the line is considered clean. This method is used to clean the main high-pressure steam supply piping as well as the hot and cold reheat steam piping, steam bypass piping, and low pressure steam piping systems. These blows are carried out separately for each system, and in some cases, done in combination with other systems. Following the steam blow procedure of the four CT/HRSG sets, the steam blow procedure is done on the combined steam lines of the CT/HRSG to the main turbine.

The steam blow procedure is carried out at about 600 psi, which is less than the 2000 psi under normal operating conditions. This requires that the CT load be at less than 50 percent operating levels to supply the required steam. Further, it is desirable to thermally cycle the piping during the process, which requires CT shutdowns and restarts.

The 90-day period referenced for steam blow is the calendar duration from initiation of the process until completion for all four CT/HRSGs and main steam lines to the steam turbine. The process will be intermittent throughout the 90-day period. There are numerous activities involved exclusive of the steam blow procedure. For example, temporary steam blow piping and valves must be removed and reinstalled for the various steam blowing operations. Occasionally, equipment repair or replacement is necessary; and there may be delays due to weather or other event. The duration of steam blowing is indeterminate but can be performed within the 90 day period requested.

Comment 1FDEP-7: Maximum Achievable Control Technology for HAPS: "Do the proposed emissions rates for these pollutants include emissions during startup and shutdowns? Please explain."

Response: The emission rates for HAPs indirectly accounted for any HAPs during startup and shutdown. Emissions of HAPs were conservatively estimated by using the following assumptions:

- 100 percent load for all operation,
- 8,760 hour per year operation,
- Maximum use of duct firing, power augmentation and peak operation, and
- Conservatively high emission factors.

The maximum HAPs using these assumptions were estimated to be 15.1 TPY for all HAPs and 6.1 TPY for a single HAP (see Table A-9 in Air Permit Application and PSD Analysis, Appendix 10.1.5 of SCA). These maximum HAP emissions are considerably less than the major HAP thresholds of 25 TPY for all HAPs and 10 TPY for a single HAP.

As noted in the preceding response, the startup times are relatively short duration and at much lower loads than that at base load. While concentrations of some air pollutants increase, the operation at lower loads produces much less relative mass emission.

Comment 1FDEP-8: BACT for Carbon Monoxide

Comment 1FDEP-8a: "On the BACT economic analysis, what is the basis (i.e., vendor's quote, capital recovery data) of the values given for the oxidation catalyst (OC). Provide us with the names of all manufacturers that were contacted along with their estimates while developing capital and annualized cost estimates for this project. Total proposed annualized cost per unit of $691,000 appears to be higher than annualized cost for recent combined cycle projects reviewed by the Department (i.e., Cana at $355,941 and El Paso at $485,924). The cost effectiveness dollar/ton is also lower for those projects (i.e., Cana at $2,852 and El Paso at $2,475) compared to the proposed cost of $4,409 for this project. Please recalculate the CO economic analysis. Describe what alternative was used in the economic analyst, the installation of the catalyst prior to the HRSG or within the HRSG (page 4-15 of the application)?"

Response: The CO BACT analysis of oxidation catalyst is based on vendor quotes from Engelhard using procedures from the EPA Cost Control Manual. The cost effectiveness for Manatee Unit 3 was $4,409 per ton of CO removed. The cost quotes received from Engelhard and used in developing the supporting BACT analysis can be found in Attachment D of this document. The oxidation catalyst system used in the economic analysis involved a system to be designed within the heat recovery steam generator (HRSG). This system would control all the CO emissions, including CO from the CTs and duct burners. Attachment E contains the economic cost analysis based on vendor data. The total annualized costs were developed by annualizing the capital costs and incorporating direct annual and energy costs. The capital costs were estimated using the procedures in the EPA Cost Control Manual. The direct annual and energy costs were developed from vendor and engineering estimates. The result was an annualized cost of $691,000. Cost for other projects may be different based on the scope of each project. With regard to the Cana Project (i.e., CPV Cana Ltd.) the Department did not require an oxidation catalyst at a cost effectiveness of $2,852 per ton removed. In addition, the Department did not proposes an oxidation catalyst for the El Paso Projects with a cost effectiveness of $2,475 per ton of CO removed. For projects using the GE Frame 7FA turbine, the Department has not determined that oxidation catalysts are BACT. The conclusions reached by the Department in these permitting reviews, clearly suggest that an oxidation catalyst would not be appropriate for the Manatee Unit 3 Project.

Comment 1FDEP-8b: "The requested CO BACT emission rates of 24.5 ppmvd at 15% O_2 (duct burning), 29.5 ppmvd at 15% O_2 (duct burning and high power modes [HPM] of operation) do not represent current CO BACT control levels. At these levels, the Department believes that an oxidation catalyst may be cost effective. Please comment."

Response: The requested CO BACT emission rates are in units of ppmvd not corrected to 15-percent O_2. The corresponding values of the requested CO emission rates in units of ppmvd at 15-percent O_2 are as follows:

- 14.7 ppmvd at 15-percent O_2 (gas firing with duct burning)
- 19.2 ppmvd at 15-percent O_2 (gas firing with duct burning and power augmentation or peaking)

Please refer to Table A-2 of the PSD Application (Appendix 10.1.5 of the SCA). Since GE provides CO emission guarantees based on ppmvd and not corrected to 15-percent O_2, the proposed emissions provided in the application are in units of ppmvd when duct firing. CO emission limits for other similarly large combined cycle projects (i.e., >500 MW) ranged from 16 ppmvd at 15-percent O_2 for the Hines Energy Complex to 17 ppmvd at 15-percent O_2 for the Osprey Energy Center. Both limits were 24-hour block averages.

The addition of an oxidation catalyst is not considered appropriate nor cost effective, given the "insignificant" ambient air impacts, collateral environmental effects and cost effectiveness. The cost effectiveness was estimated to be $4,409 per ton of CO removed. This also assumed maximum worst case emissions, which is extremely conservative given the actual performance of the GE Frame 7FA as acknowledged by the department in recent permits. Moreover, there are no secondary environmental benefits of an oxidation catalyst since the amount of backpressure and lost energy ultimately results in the generation of more CO_2 than is being controlled in the oxidation catalyst (refer to Tables B-10 and B-11 in Appendix B of the Air Permit/PSD Application; Appendix 10.1.5 of the SCA).

Comment 1FDEP-8c: "Provide supporting documentation that duct burning and HPM operations would increase emissions from 7.4 ppmvd at 15% O_2 (GE guarantee) to 24.5 ppmvd at 15% O_2 (duct burning) and to 29.5 ppmvd at 15% O_2 (HPM)."

Response: This information was presented in Appendix A of the PSD Application (Appendix 10.1.5 of the SCA).

CO (lb/hr) = CO(ppm) x [1 - Moisture(percent)/100] x 2116.8 lb/ft^2 x Volume flow (acfm) x 28 (mole wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]

A. At an ambient temperature of 95 F, given the CT CO emission rate of 25.5 lb/hr based on the GE guarantee, and the duct burner (DB) CO emission rate of 0.08 lb/MMBtu and a heat input of 550 MMBtu/hr, the CT/DB emission rate is equivalent to 69.5 lb/hr. For this operating case, the moisture, temperature are as follows: 12.17 percent, 1143 F.

See Attachment C for the calculation of the volume flow rate for the CT and DB equal to 2,277,437 acfm.

The resulting CO ppmvd emission concentration equals 24.5 ppmvd or 14.7 ppmvd at 15-percent O_2.

B. At an ambient temperature of 80 F and operation in power augmentation, given the CT CO emission rate of 45 lb/hr based on the GE guarantee, and the duct burner (DB) CO emission rate of 0.08 lb/MMBtu and a heat input of 550 MMBtu/hr, the CT/DB emission rate is equivalent to 89 lb/hr. For this operating case, the moisture, temperature are as follows: 19.2 percent, 1125 F.

See Attachment C for the calculation of the volume flow rate for the CT and DB equal to 2,403,989 acfm.

The resulting CO ppmvd emission concentration equals 29.5 ppmvd or 19.2 ppmvd at 15-percent O_2.

Comment 1FDEP-8d: "Other States, including New York, Massachusetts, New Jersey, Arizona, Connecticut, Washington, and California have enforced BACT standards by permitting a large number of gas-fired combined and simple cycle power plants with CO limits of 2 to 6 ppmvd at 15% O_2 averaged over 3 hours and achieved using oxidation catalyst. Continuous compliance is demonstrated using CEMs, based on 3-hour averages. Please comment."

Response: New York, Massachusetts, New Jersey, Arizona, Connecticut, Washington, and California, are states that have non-attainment areas for various pollutants. As such, new "major" facilities attempting to locate within ozone non-attainment areas, are potentially subject to New Source Review (NSR) requirements for non-attainment areas. As precursor pollutants to the formation of ozone, NO_x and VOC emissions are potentially subject to NSR requirements, including the installation of Lowest Achievable Emission Rate (LAER) control technology. In ozone non-attainment areas, LAER for VOC emissions from combined-cycle power facilities, which does not consider cost effectiveness, has typically been determined to be oxidation catalyst. An oxidation catalyst would be the same as that which can be implemented for CO control. The installation of an oxidation catalyst as LAER for VOC would also limit CO emissions. However, only BACT would be applicable to CO. Therefore, similar power facilities in New York, Massachusetts, New Jersey, Connecticut, and California have the requirement to install oxidation catalyst based on LAER requirements for VOC and not BACT. The Manatee power plant is located in Manatee County, which is attainment for all pollutants. Therefore, Unit 3 is subject to PSD BACT requirements and not LAER for both VOC and CO.

Comment 1FDEP-8e: "Oxidation catalyst are technically feasible and can be cost effective for both simple and combined cycle applications. They are also essential to control toxic emissions, particularly from simple cycle turbines that experience a large number of startups. Please comment."

Response: Although oxidation catalyst are considered technically feasible for both combined and simple cycle CTs, the addition of an oxidation catalyst is not considered appropriate nor cost effective, given the "insignificant" ambient air impacts, collateral environmental effects and cost effectiveness. The cost effectiveness was estimated to be $4,409 per ton of CO removed.

The GE 7FA CTs for this project will incorporate dry low NO_x (DLN) burners as a part of the emission control system. DLN combustion makes use of lean premix technology, originally introduced in the 1990s. Although this project will also use SCR, DLN was originally developed to reduce NO_x emissions without additional controls (i.e., SCR). DLN combustion premixes fuel and air prior to the combustor and as a result limits flame temperature and the residence time at the peak flame temperature. The resulting lower temperature results in lower NO_x, CO, and HAP formation. According to the August 21, 2001, memorandum from Roy Sims of the Emission Standards Division, Combustion Group, entitled "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines," for control of HAPs, "lean premix combustion is a comparable technology to oxidation catalyst systems." This conclusion was the result of EPA analysis of HAP emissions from lean premix combustion turbines in the range of 10 to 170 MW, compared with emission factors for diffusion flame stationary combustion turbines equipped with oxidation catalyst systems. The results of this analysis show that HAPs from lean premix CTs are equal or lower than HAPs from diffusion flame CTs with oxidation catalyst. The proposed CTs will employ DLN combustion and as a result HAP emissions from the facility will be less than 25 TPY for all HAPs and less than 10 TPY for any single HAP. The proposed project is not a major source for HAPs by itself and it is not a reconstruction of the existing facilities at the Manatee Plant. Therefore, the requirements of 40 CFR 63.43 for a maximum control technology are not applicable to the project.

In addition, Manatee Unit 3 is a base-load unit with limited startups and shutdowns. Also refer to the responses to Comments 1FDEP-9 and 1FDEP-11.

__Comment 1FDEP-9: CO Emissions Increase or Decrease__: "What would be the overall increase or decrease in emissions for the facility as a result of applying the oxidation catalyst technology in the new units? The application states that *" the end results is an additional 1,970 TPY of carbon dioxide (CO_2)*. Please submit an explanation of this statement (compare the decrease (in tons per year) of the operation of the new units with oxidation catalyst versus the increase of the operation of the older units as a result of supplying needed energy). Refer to page 4-16 of the application."

__Response__: The increases and decreases for installing an oxidation catalyst is presented in Table B-11 of the Air Permit/PSD Application (Appendix 10.1.5 of the SCA). The CO from each unit would be calculated decreased by 156.7 tons per year (TPY) from the emission rates guaranteed by General Electric and those anticipated to be guaranteed by the duct burner manufacturer (see response to 1FDEP-3). As discussed, in Section page 4-17, the actual decrease resulting from the addition of an oxidation catalyst is not expected to be that beneficial given the actual performance of the GE Frame 7FA turbine. As shown in Table B-11, the backpressure on the turbine results in a direct loss of electric power that would otherwise be placed on the electric grid. The amount of power lost as a result of the backpressure is about 3 million KW-hr per year. To replace this power, other less efficient units are operated within the electric system, since electric power is being supplied to meet demand. The demand is independent of the unit operation and any energy lost within the operation of the units cannot be used to meet the demand. To meet demand, the older less efficient power units are operated. This will result in the generation of secondary air pollutants by these units even if the increment of power needed is small. For example, units that cycle would be operated at an incrementally higher load to supply the power lost. To convert the lost energy into thermal energy requirements, a heat rate of 10,300 Btu/kW-hr was used. The energy requirements was 31,121 MMBtu/year (i.e., 3,012,149 kW-hr x 10,301 Btu/kW-hr x MM/10^6 = 31,121 MMBtu/hr). The secondary air pollutants were estimated to be about 4 TPY of criteria pollutants and 1,970 TPY of carbon dioxide. As discussed on page 4-16, the amount of CO_2 produced as a direct result of the lost energy is more than 10 times higher than the amount of CO theoretically reduced (i.e., 156.7 TPY) and converted to CO_2 in the oxidation catalyst. While it is certain that energy lost that is not available to meet demand must be replaced, it is uncertain the exact type of unit that would replace the lost energy. Typically these are cycling units much lower on the dispatch order than Manatee Unit 3. In the FPL system it is likely that the unit is an oil/gas-fired steam unit. It was assumed that the lost power would be replaced using natural gas fired unit.

Comment 1FDEP-10: BACT for NO_x

Comment 1FDEP-10a: "Appendix B, Tables for hot SCR appears to be missing. Please submit. Other states, including New York, Connecticut, Illinois and California have enforced BACT standards by permitting a large number of gas-fired simple cycle peaking power plants with NO_x limits of 2 to 6 ppmvd at 15% O_2 averaged over 1 to 3 hours and achieved using high temperature selective catalytic reduction (SCR). Continuous compliance is demonstrated using CEMs , based on 1 hour to 3 hour averages. Please comment."

Response: These tables were inadvertently omitted and are provided as Attachment F. The Manatee Unit 3 Project is a combined cycle project. Simple cycle operation is only being requested to operate for a maximum fuel equivalent of 3,390 hours of hours during the first year of operation and for a maximum fuel equivalent thereafter of 1,000 hours per year when combined cycle operation is not functioning. SCR is technically feasible and demonstrated for combined cycle operation, while "hot" SCR is not demonstrated on "F" Class turbines.

New York, Connecticut, Illinois, and California, are states that have non-attainment areas for various pollutants. As such, new "major" facilities or "major" modifications to existing facilities within these non-attainment areas, are potentially subject to New Source Review (NSR) requirements. As precursor pollutants to the formation of ozone, NO_x and VOC emissions are potentially subject to NSR requirements in ozone non-attainment areas, including the installation of LAER control technology. In non-attainment areas, LAER for NO_x emissions from simple-cycle power facilities has typically been determined to be SCR control to 2.0 - 2.5 ppmvd corrected to 15 percent O_2. Therefore, power facilities in New York, Connecticut, Illinois, and California may have the requirement to install "Hot" SCR based on NSR requirements of LAER control technology, a more stringent requirement than BACT that does not consider cost effectiveness or collateral energy of environmental impacts. However, many of the projects are smaller turbines than the "F" Class turbine proposed for the project. A review of Attachment G, EPA Region IV's "National Combustion Turbine List," (http://www.epa.gov/region4/air/permits/national_ct_list.xls) for New York, Connecticut, Illinois, and California, indicates that NO_x BACT for simple cycle combustion turbines to be dry low NO_x (DLN) not hot SCR. The Manatee power plant is located in Manatee County, which is attainment for all pollutants and therefore, the proposed facility is subject to PSD BACT requirements, not

NSR LAER. A review of EPA Region IV's "National Combustion Turbine List," also indicates a range of 1-24 hour averaging times for BACT continuous compliance on similar projects.

Comment 1FDEP-10b: "Please evaluate the cost effectiveness of reducing NO_x emissions to 2.0 ppmvd at 15% O_2 by SCR. Other states, including New York, Connecticut, Massachusetts, Rhode Island, New Jersey, Arizona, Washington and California has enforced BACT standards by permitting a large number of gas-fired combined cycle power plants with NO_x limits of 1.55 to 2.5 ppmvd at 15% O_2 averaged on 1-hour average. Please comment."

Response: Attachment H contains the revised cost effectiveness of reducing NO_x emissions to 3.5, 2.5, and 2.0 ppmvd at 15-percent O_2 by SCR. New York, Connecticut, Massachusetts, Rhode Island, New Jersey, Arizona, Washington and California, are states that have non-attainment areas for various pollutants. As such, new "major" facilities or "major" modifications to existing facilities within these non-attainment areas, are potentially subject to New Source Review (NSR) requirements. As precursor pollutants to the formation of ozone, NO_x and VOC emissions are potentially subject to NSR requirements, including the installation of LAER control technology. In non-attainment areas, LAER for NO_x emissions from combined-cycle power facilities has typically been determined to be SCR control to 2.0 - 2.5 ppmvd corrected to 15-percent O_2. Therefore, similar power facilities in New York, Connecticut, Massachusetts, Rhode Island, New Jersey, Arizona, Washington and California may have the requirement to install SCR based on NSR requirements of LAER control technology, a more stringent requirement than BACT. A review of EPA Region IV's "National Combustion Turbine List," http://www.epa.gov/region4/air/permits/national_ct_list.xls, for New York, Connecticut, Massachusetts, Rhode Island, New Jersey, Arizona, Washington and California, indicates that NO_x BACT for combined cycle combustion turbines to be SCR control to 2.5 to 4.5 ppmvd corrected to 15-percent O_2. The Manatee power plant is located in Manatee County, which is designated as attainment for all pollutants and therefore, the proposed facility is subject to PSD BACT requirements not NSR LAER.

Comment 1FDEP-11: BACT Social Impacts: "Expand the BACT analysis to include the social impact of the application of selective catalytic reduction (SCR) and oxidation catalysis (OC)?"

Response: Although not described as "social impacts," the BACT analyses for SCR and oxidation include components of social impacts for the technology. These are describe further below:

Social Impacts of SCR: The social impacts of SCR are incorporated within the economic and energy impacts described in the Section 4 of the Air Permit/PSD Application. From a social perspective, the use of SCR has implications of both costs and benefits. The capital cost of the SCR ($2,645,725 from Table B-5A) will generate some direct economic benefits. Since SCR equipment is specialized these benefits would primarily accrue to the manufacturer, which would be located out of Florida. Installation would be at the unit and likely be limited to several weeks of labor effort. The cost for SCR is estimated to be about 0.06 cents per KW-hr, which will be passed to FPL's customers. (Calculation: $1,446,073/unit/year x 1 unit/287,500 kW/hr x year/8,760 hrs x 100 cents/$; refer to Table B-5a). With SCR, the lost power for each CT/HRSG would be sufficient to supply about 493 residential customers. This is about 0.24 percent of the electric energy that would be supplied by each CT/HRSG. SCR equipment and systems would have to be maintained and would require about 0.6 man-years per CT/HRSG. This will generate economic benefits through payroll, which has been estimated to be about $19,000/year per CT/HRSG. Pollution control equipment, such as SCR, is tax exempted from property taxes. The use of ammonia would be supplied in state (estimated to be about $110,000 per CT/HRSG) and would generate about one trip per week for delivery. A Risk Management Plan (RMP) may be required depending upon the type and quantities of ammonia. SCR would remove about 76 percent of NO_x or a potential of 254 TPY. This benefit is somewhat offset due to the emissions of ammonia, PM and secondary emissions. While the NO_x reduction would not significantly reduce ground-level concentration of NO_2 (as compared to ambient air quality standards), the reduction of NO_x would be beneficial in reducing a precursor to ozone formation.

Social Impacts of Oxidation Catalyst (OC): The social impacts of OC are incorporated within the economic and energy impacts described in the Section 4 of the Air Permit/PSD Application. From a social perspective, the use of OC has implications of both costs and benefits. The capital cost of the OC ($1,644,300 from Table-B10) will generate some direct economic benefits. Since OC equipment is specialized these benefits would primarily accrue to the manufacturer, which would be located out of Florida. Installation would be at the unit and likely be limited to several weeks of labor effort. The cost for OC is estimated to be about 0.027 cents per KW-hr, which will be passed to FPL's customers. (Calculation: $691,000/unit/year x 1 unit/287,500 kW/hr x year/8,760 hrs x 100 cents/$; refer to Table B-10). With OC, the lost power for each CT/HRSG would be sufficient to supply about 252 residential customers. This is about 0.12 percent of the electric energy that would be supplied by each CT/HRSG. OC equipment and systems would have to be maintained and would require about 0.2 man-years per CT/HRSG. This will generate economic benefits through payroll, which has been estimated to be about $6,000/year per CT/HRSG. Pollution control equipment, such as OC, is tax exempted from property taxes. OC would remove 90 percent of CO or a potential of 156.7 TPY. This benefit is somewhat offset due to the emissions of PM and secondary emissions. The CO reduction would not significantly reduce ground-level concentration of CO (as compared to ambient air quality standards).

Comment 1FDEP-12: Energy Replaced: "How much energy (MW) from these new units will replace energy from the older, less efficient units?"

Response: Manatee Unit 3 is being built to serve the growing energy and capacity needs of FPL's customers both old and new. It is not being built for the purpose of displacing energy from existing units, however, operation of the Manatee unit will have the effect of displacing energy from such units.

The actual amount of energy that the Manatee unit will displace from other, existing units will vary from year-to-year based on a number of factors (fuel prices, load growth, weather, maintenance schedules, improvements to other units, etc.). However, the following simple calculation should provide a useful "ballpark" projection of the amount of energy that Manatee's Unit 3 may displace from other, existing units.

If we round off (to keep the math simple) Manatee Unit 3's capacity to 1,100 MW, then the maximum amount of energy it can produce in a year is 1,100 MW x 8760 hours/year = 9,636,000 MWh/year. Since no plant operates 100 percent of the hours in a year, assume that Manatee Unit 3 runs 90 percent of the hours per year at full load (rounding off again to keep the math simple). Therefore, its total annual MWh output is reduced to: 9,636,000 MWh/year x 0.90 = 8,700,000 (approx.).

Also assume that FPL will have most/all of its generating units operating during very high load periods only 10 percent of the hours in a year. During those hours no unit, including Manatee Unit 3, will be displacing the output of other units since all available units would be running. Therefore, in this example, the amount of energy that Manatee Unit 3 would displace from currently existing units is reduced by 10 percent. Consequently, Manatee's projected displacement of the output from other, existing plants would be: 8,700,000 MWh (approx.) x 0.90 = 7,800,000 MWh (approx.) or 7,800 Gigawatt-hours (GWh) (approx.) per year. To put this in perspective, 7,800 GWh is equivalent to the amount of energy produced by two 800-MW generating units operating at a 55 percent annual capacity factor.

As mentioned above, the actual displacement will depend totally on the factors listed above, and will vary from year-to-year. This simple calculation is intended to provide an illustrative useful order-of-magnitude projection only.

Comment 1FDEP-13: Emission Offset: "Is FPL considering to reduce emissions from the old units as a result of the operation of the new units? If so, how would this be accomplished? Please explain."

Response: FPL does not propose a specific reduction in emissions from Manatee Unit 1 and 2 "as a result of the operation" of new Unit 3. It is entirely possible that the addition of 1100 MW of new highly efficient combined cycle capacity at the Manatee Plant site beginning in 2005 will result in a lower capacity factor for Units 1 and 2, with resulting decreases in annual emissions. In fact, FPL's resource planning group projects that Units 1 and 2 will have lower annual capacity factors (and hence lower annual emissions) from 2002 through 2006, compared to the 2000-2001 annual capacity factors. The actual annual capacity factors for Units 1 and 2 will be determined by a number of factors, including fuel prices, weather, load demand, unit availability and maintenance schedules. Given these and other factors, FPL's obligation to provide adequate, reliable and reasonably-priced electricity to its customers will ultimately dictate how much Units 1 and 2 will run. Emissions from these Units will also be affected by the fuel they burn. The addition of natural gas as an optional fuel for Units 1 and 2 offers the opportunity for improved environmental performance and reduced emissions to the extent that natural gas is fired in lieu of No. 6 fuel oil.

Comment 1FDEP-14: Flow Diagram: "Include a flow diagram representative of the project, including all 4 units, stacks, HRSG & duct burners, etc."

Response: See Attachment I for a flow diagram representative of the project.

Comment 1FDEP-15: Gas Fired Heaters: "Please describe when fuel gas heating is necessary (application page 2-3). Why will these heaters operate only during the simple cycle mode? Is there a separate heat transfer system used during the combined cycle mode?"

Response: The GE 7FA combustion turbine is available with two types of DLN combustors that fire natural gas. The first type is called a "cold" nozzle and the second type is a "hot" nozzle. FPL uses the hot nozzle design because it uses hot fuel (290-365°F) which is heated using waste energy from the combustion turbine exhaust via a feed water heat exchanger. This improves the overall plant efficiency. The hot nozzles require a temperature of the natural gas to be 290°F when at a minimum continuous load of (30 MW). The energy to heat the fuel from a feed water heater is not available in simple cycle mode since there is no steam cycle and is not available during initial start up. The energy to heat the natural gas during these conditions must be supplied from another source, which is a direct fired gas heater. The direct fired gas heaters are used in simple cycle mode and may be used during the first 30 to 60 minutes of startup in combined cycle mode. In full combined cycle mode the fuel heaters are not required since waste heat from a feed water heater is used. For the first year of operation in simple cycle mode and during the plant start up phases, there will be times when the fuel gas heaters will be required to operate.

Comment 1FDEP-16: Additional Comments: "Comments from EPA and Manatee County will be forwarded when received."

Response: No comments from EPA or Manatee County on the separate PSD application have been received at the time of submission of the sufficiency responses. Manatee County provided separate sufficiency comments, which have been addressed separately.

Comment 1FDEP-17: Air Quality Analysis: "Rule 62-212.400(3)(h)(5) states that an application must include information relating to the air quality impacts of, and the nature and extent of, all general, commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Please satisfy this rule requirement as it relates to the Manatee Expansion facility."

Response: There has been minimal industrial, commercial, and residential growth within a 5-mile radius of the FPL Manatee Plant site since 1977. The site itself consists of 9,500 acres that is wholly owned by FPL.

The plant is located in a rural area of Manatee County that has a minimal number of air pollution industrial and commercial sources near the site. Since the baseline date of August 7, 1977, there has been no major facilities built within a 10-mile radius. TECO Big Bend Station is the closest PSD source, located approximately 13.5 miles from the Manatee site. As presented in Section 6 of the Air Permit/PSD Application (Appendix 10.1.5), a cumulative impact analysis was conducted for PM_{10} and included the TECO Big Bend Station.

There are also very few residences near the plant site. Surrounding land uses are almost exclusively agricultural with the exception of the Willow Shores residential area north of the railroad at the northeast corner of the site. Individual homes are located in the larger of the outparcels within the site, along State Road (SR) 62 at the southern perimeter along Saffold Road at the northeast corner of the Manatee Plant Site.

The existing commercial and industrial infrastructure should be adequate to provide any support services that the Project might require. Construction of the Project will occur over a 24-month period requiring an average of approximately 250 workers during that time. It is anticipated that many of these construction personnel will commute to the Site. At project build-out the plant will employ a total of 12 operational workers. This workforce needed to operate the proposed Project represents a small fraction of the population present in the immediate area. Population and housing impacts from construction and operation will be minimal because little migration into the area is anticipated. Additionally, there are expected to be no air quality impacts due to associated industrial/commercial growth given the location at the existing Manatee Plant.

Since 1977, Manatee County has been classified as attainment for all criteria pollutants. The nearest ambient monitor to the Project is located at Palmetto/Port Manatee (AIRS No. 12-081-3002). Data collected from this station is considered to be representative of air quality in Manatee County. A summary of the maximum pollutant concentrations measured in Manatee County from 1998 through 2001 is presented in Table 2.3-14 of the SCA application. These data indicate that the maximum air quality concentrations measured in the region comply with and are well below the applicable ambient air quality standards.

Additionally, results of air modeling analyses demonstrate that the Project by itself and with other emission sources will comply with all applicable AAQS and PSD increments.

Comment 1FDEP-18: "In the application submitted, Table F-2, the first footnote about the meteorology data does not correspond with the meteorology information throughout the remainder of the application. Please verify that the footnote is incorrect."

Response: The first footnote of Table F-2 should read as follows: Concentrations are based on highest concentrations predicted using five years of meteorological data from 1991 to 1995 of surface and upper air data from the National Weather Service station at Tampa International Airport.

Comment 1FDEP-19: "The *Additional Impact Analysis* analyses the effects of PM, PM_{10}, SO_2, NO_x, CO, and sulfuric acid mist, all pollutants subject to PSD review, have on soils, vegetation, wildlife and visibility. Please include VOC emissions in your analysis since it is also subject to PSD review."

Response: It is difficult to predict what effect the proposed facility emissions of VOC will have on ambient ozone concentrations from either a local or regional scale. VOC and NO_x emissions are precursors to the formation of ozone. Ozone is not directly emitted from fossil fuel combustion, but is formed down-wind from emission sources when VOC, and NO_x emissions from the facility react in the presence of sunlight. Natural (without man-made sources) ambient concentrations, of ozone are normally in the range of 20 to 39 $\mu g/m^3$ (0.01 to 0.02 ppm) (Heath, 1975).

The nearest monitor to the Project that measures ozone concentrations is located at Palmetto/Port Manatee (AIRS No. 12-081-3002). This Station is operated by Manatee County and measures concentrations according to EPA procedures. Based on the ozone monitoring concentrations measured over the last several years in Manatee County, the county is in attainment of the existing 1-hour ozone ambient air quality standard (AAQS) as well as the new 8-hour ozone AAQS.

To ensure that the area will remain attainment for ozone, future broad-based local and regional reductions of NO_x and VOC emissions are planned. Large NO_x emission reductions (>60,000 tons) will occur in the area from the TECO Big Bend and Gannon power stations over the next 10 years. Additionally, VOC and NO_x emissions from new cars and trucks will be more restrictive as part of the Tier II EPA Standards. For specific details of the estimated local and regional emission reductions see the response to Comment 1FDEP-20.

Vegetation

Ozone can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis and markings on the upper surface of leaves known as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. Ozone can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

Vegetative communities at the Manatee site consist of open grassed lawn that is periodically mowed. No ozone-sensitive species are found on the Project site. The surrounding vicinity includes row crops (primarily tomato), pastures, mixed pine-oak forest, and freshwater marshes.

Therefore, the effects of ozone on vegetation, as a result of VOC emissions from the Project, are expected to be insignificant.

Soils

According to the USDA Soil Survey of Manatee County, soils at the project site include Duette, Myakka, and Pomello fine sands. Surrounding areas are dominated by Eau Gallie fine sand and the Floridana-Immokalee-Okeelanta association. Many of the soils in the region and a large portion of the site have been disturbed and altered by agricultural and industrial activities. The Duette series consists of moderately well drained soils that formed in thick deposits of marine sand. Myakka fine sand is a poorly drained soil formed in sandy marine deposits that are underlain in places by shell fragments. It is found in pine flatwoods as well as in tidal marsh areas. Pomello fine sand is a deep, moderately well drained soil formed in thick deposits of sandy marine sediment. The soil of the surrounding cropland and pastures is Eau Gallie fine sand, a poorly drained soil formed of sandy and loamy marine sediments. The poorly drained Eau Gallie fine sands are acidic, requiring liming for agricultural uses. Numerous depressional wetlands are found in the vicinity of the site, underlain by the Floridana-Immokalee-Okeelanta soil association. This very poorly drained, slowly permeable soil often contains standing water at the surface. In all horizons, reaction ranges from medium acidic to mildly alkaline. The facilities contribution to ground level ozone is expected to be very low and dispersed over a large area. No impacts from ozone to soils at the project and the surrounding vicinity are expected.

Wildlife

Although air pollution impacts to wildlife have been reported in literature, many of the incidents involve acute exposure to pollutants, usually caused by unusual or highly concentrated releases or unique weather conditions. Research with primates shows that ozone penetrates deeper into non-ciliated peripheral pathways and can cause lesions in the respiratory bronchioles and alveolar ducts as concentrations increases from 0.2 to 0.8 ppm (Paterson, 1997). These bronchioles are the most common site for severe damage. In rats, the Type 1 cells in the proximal alveoli (where gas exchange occurs) were the primary site of action at concentrations between 0.5 and 0.9 ppm (Paterson, 1997). Work with rats and rabbits suggest that the mucus layer that lines the large airways does not protect completely against the effects of ozone, and desquamated cells were found from acute exposures at 0.25, 0.5 and 1.0 ppm. In animal research, ozone has been found to increase the susceptibility to bacterial pneumonia (Paterson, 1997). During the last decade, there also has been growing concern with the possibility that repeated or long-term exposure to elevated O_3 concentrations may be causing or contributing to irreversible chronic lung injury.

The facilities contribution to ground level ozone is expected to be very low and dispersed over a large area. Coupled with the historical ambient data, mobility of wildlife, the potential for exposure of wildlife to the facilities impacts that lead to high concentrations is extremely unlikely.

Visibility

No visibility impairment in the Project's vicinity is expected due to the types and quantities of emissions proposed for the Project. The opacity of the proposed exhaust emissions for both simple and combined cycle operation will be 10 percent or less. In addition, a regional haze analysis was performed for the Chassahowitzka NWA, and the results indicate that the Project's maximum predicted impacts are below the FLM's screening criteria and therefore are not expected to have an adverse impact on the existing regional haze.

Comment 1FDEP-20: "A pre-construction ambient monitoring analysis for ozone, based on VOC emissions, was required as part of the application for the Manatee Expansion. Please elaborate on the analysis you submitted."

Response: As shown in Table 3.4-1 in Chapter 3 and in Table 3-4 in Chapter 10.1.5, *Air Permit Application and Prevention of Significant Deterioration Analysis*, of the Site Certification Application, the Project's VOC emissions are greater than the *de minimis* monitoring emission level of 100 TPY. Therefore, pre-construction ambient monitoring analyses for ozone (based on VOC emissions) are required to be submitted as part of the application.

As a result, ambient monitoring data from existing monitoring stations operated by FDEP and Manatee County were included in this application to satisfy the pre-construction monitoring requirement. This information is presented in Table 2.3-14 in Chapter 2 of the Site Certification Application. Manatee County and adjacent counties are classified as attainment for ozone. The nearest monitor to the Project that measures ozone concentrations is located at Palmetto/Port Manatee (AIRS No. 12-081-3002). This station is located about 10 miles west of FPL Manatee. The station is operated by Manatee County and measures concentrations according to EPA procedures.

As discussed in Section 5 of Chapter 10.1.5 of the application, from 1998 through July 2001, the second-highest 1-hour average ozone concentration measured at this site was 0.112 ppm. This maximum concentration is less than the existing 1-hour average ozone AAQS of 0.12 ppm. In addition, the 3-year average of the 4th highest 8-hour average ozone concentration in 2001 was 0.079 ppm that is below the proposed 8-hour average ozone AAQS of 0.08 ppm. These O_3 monitoring data are proposed as part of this construction permit application to satisfy the preconstruction monitoring requirement for the project.

Therefore, based on the existing ozone ambient data, an exemption from the preconstruction monitoring requirement for ozone in accordance with the PSD regulations is appropriate.

Comment 1FDEP-21: "What are the ozone readings from Manatee County? How far away from FPL Manatee is the Port Manatee monitor? How many exceedances have Manatee ozone monitors had in the past year? Why do you think the Expansion will not contribute to a violation of the standard?"

Response: The ozone readings for Manatee County were presented in Table 2.3-14 in Chapter 2 of the Site Certification Application and discussed in response to Comment 1FDEP-20. The Port Manatee monitor is about 10 miles west of FPL Manatee.

Based on the ozone monitoring concentrations measured over the last several years in Manatee County, the county is in attainment of the existing 1-hour ozone ambient air quality standard (AAQS) as well as the new 8-hour ozone AAQS. In fact, ozone monitoring data measured during 2001 in the counties surrounding the Tampa Bay area, including Manatee, Hillsborough and Pinellas Counties, show that these counties are complying with the both the 1-hour and 8-hour AAQS. As shown in Table 2.3-14, there have been no observed 1-hour concentrations at the Port Manatee monitor in excess of the currently applicable AAQS for the period 1999 through 2001.

It should be noted that, in March 2002, the courts upheld the new 8-hour standard which will be implemented by EPA and the Florida DEP within several years. At present, the 1-hour AAQS is still applicable. Based on these monitoring data, the area is still classified by EPA as in attainment of the ozone standard.

In order to reduce ozone levels in Manatee County, broad-based local and regional emission reductions in the precursors to ozone, NO_x, and VOC. The Florida DEP is addressing this situation in the Tampa Bay area by requiring sufficient area-wide reductions of VOC and/or NO_x to ensure that this area will remain in compliance with the ozone standard.

Although the regulatory process has been delayed because of court challenges to the 8-hour standard, the Florida DEP has identified a number of existing requirements that will significantly reduce ozone precursors in the Tampa Bay area. These requirements include:

- large NO_x reductions (>60,000 TPY) from the TECO Order for the Big Bend and Gannon Stations over the next 10 years; and
- emission reductions from existing and new vehicles beginning in 2004 due to:
    - low sulfur gasoline (low sulfur gasoline reduces NO_x emissions in cars and trucks);
    - low sulfur diesel fuel; and
    - more restrictive VOC and NO_x emissions for new cars and trucks as part of the Tier II standards implemented by EPA.

By 2004, the NO_x emission reductions from the TECO stations will amount to nearly 30,000 TPY from 1998 emissions; by 2010, the NO_x reductions will be more than 60,000 TPY.

Based on emission data for Manatee County provided by the Florida DEP, the VOC and NO_x emission reductions from existing and new vehicles in 2005 will amount to about 3,300 and 3,800 TPY, respectively; by 2010, these emission reductions will amount to about 5,600 and 8,300 TPY, respectively. These emissions reductions will occur even with increases in traffic volume projected for the county.

Based on the proposed local and regional VOC and NO_x emission reductions for the Tampa Bay area, it is expected that the VOC and NO_x increases due to the addition of Unit 3 will not interfere with the Tampa Bay area-wide strategy for reducing ozone concentrations.

Comment 1FDEP-22: "Are there any fugitive emissions created from the Expansion? If so, please address them."

Response: There are no significant sources of fugitive emissions resulting from the construction or operation of Manatee Unit 3. Some fugitive particulate emissions will result from construction. These are discussed in Section 4.5 of the SCA. During operation, there will be minor amount of fugitive emissions from volatile organic compounds (VOCs). This will primarily include small amount of VOCs from lube oil vents on the equipment. There will also be maintenance activities, which will release minor amount of VOCs (e.g., painting). These activities are either exempted as categorical or generic exemptions in Rule 62-210.300(3)F.A.C.

Table 1FDEP-4. Matrix of Operating Modes

Operating Mode	Operating Condition	Fuel (s)	Stack	NO_x Limit[a] Proposed	Hours/year	Description of Hours
Simple Cycle - 1st Year	50 to 100% load	natural gas	CT Stack	9 ppmvd	3390[c]	maximum total hours for simple cycle operation
	Peak	natural gas	CT Stack	15 ppmvd	60	maximum hours
Combined Cycle - 2nd Year and Future Years	50 to 100% load	natural gas	HRSG Stack	2.5 ppmvd	8,760	maximum total hours for combined cycle operation
	HPM	natural gas	HRSG Stack	2.5 ppmvd	400	maximum hours
	Duct Firing	natural gas	HRSG Stack	2.5 ppmvd	2880[d]	equivalent aggregate heat input limit requested
Simple Cycle - 2nd Year and Future Years[b]	50 to 100% load	natural gas	CT Stack	9 ppmvd	1000[e]	maximum total hours for simple cycle operation
	Peak	natural gas	CT Stack	15 ppmvd	60	maximum hours

CT = combustion turbine. HRSG = heat recovery steam generator. HPM = Higher Power Mode and includes Peak and Power Augmentation.

[a] Corrected to 15 percent oxygen; simple cycle operation uses dry low-NO_x combustion when firing natural gas.
Combined cycle operation uses SCR located in the HRSG, along with CT controls of dry low-NO_x combustion when firing gas.

[b] When combined cycle is in operation, simple cycle mode will only be used in the event combined cycle mode is not functioning.

[c] Fuel equivalent requested: 5,902,588,000 SCF of gas per CT.

[d] Fuel equivalent requested: 6×10^9 SCF of gas for four HRSGs.

[e] Fuel equivalent requested: 1,741,176,400 SCF of gas per CT.

ATTACHMENT A

Table A-2A Natural Gas Duct Burner Emissions: Full Duct Firing

Pollutant	Emission Rate (lb/MMBtu)	Heat Input (lb/MMBtu)	Emission Rate (lb/hr)
PM-10	0.01	550	5.5
NO_x	0.1	550	55.0
CO	0.08	550	44.0
VOC	0.016	550	8.8

< Back

Custom Designed Duct Burner

PowerPlus Duct Burner

Standard Gas Fired Duct Burner

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Duct Burner General Information

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PowerPlus Duct Burner

- **Engineered for the lowest emissions with "F" & "G" class turbines**
- **Optimum performance during turbine power augmentation modes.**
- **Proven field performance**

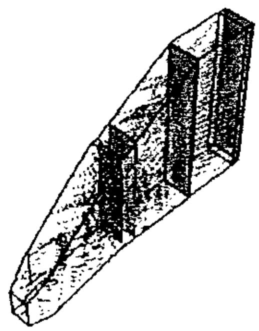
The Coen ***PowerPlus***, built on three years of R&D and extensive field experience, introduces a new generation of duct burners to the power industry. Designed to handle the most challenging "Advanced Technology Turbines", ***PowerPlus*** provides unparalleled performance, quality, and reliability. The ***PowerPlus*** is the most reliable duct burner system in the world.

Duct Burner Design Fundamentals

Today's "Advanced Technology Turbine" has a lower O_2, and higher H_2O exhaust composition than previous gas turbine designs. This shift in exhaust temperature and composition reduces local flame temperatures and as a result has a significant impact on the duct burner stability range and CO contribution. Further, CO emission limits have been decreasing in recent years. As a result, Coen initiated a duct burner improvement program in R&D. The objectives were to identify CO formation pathways and develop reduction methods, while maintaining low NOx levels.

Through Computational Fluid Dynamics (CFD) modeling, coupled with Coen test facility experiments and field data, the following were established:

- Mixing rates and chemical kinetics were identified as the controlling factors in the modeling effort
- CO formation was identified as cooling of flame partial products with upstream turbine exhaust gas (TEG) prior to complete oxidation
- Reduction of CO, UBHC's (Unburned HydrocCarbons) and



Volatile Organic Compounds (VOC's) was proven to be directly related to increasing residence time in the flame stabilizer recirculation zone and decreased mixing rates in the near field zone

- Residence time can be increased with controlled flow baffle/flame stabilizer geometry, increased with reduced TEG velocity (until buoyancy limited) and increased with reduced turbulence

Tradeoffs of the above became obvious. Simple increases in flame stabilizer size and associated recirculation size resulted in the beneficial increased residence time, but was also offset by increased TEG velocity and turbulence.& Simple bluff bodies provided excessive turbulence and mixing rates in the near field, so streamlined flame stabilizers were desired for reduced pressure drop. How to increase residence time without increases in turbulence, pressure drop or TEG velocity? Reacting CFD models indicated that it was desired to obtain a long narrow recirculation zone that minimized mixing of TEG until complete oxidation. Hundreds of configurations were modeled and analyzed.

The answer was our ***PowerPlus*** flame stabilizer arrangement. It resulted in twin recirculation zones or as we have labeled "**Dual Recirculation Technology**". This dual recirculation pattern provides for increased residence time in a narrow "corridor" without excessive blockage or undesirable flame patterns. Typical residence times with ordinary stabilizers of ***any*** shape were approximately 50 milliseconds in the recirculation zone. The ***PowerPlus*** design increases this residence time by 3 times compared to current duct burner designs. Further TEG flow is diverted to the flame ends where oxidation is nearly complete. This concept has been modeled extensively, lab tested and field confirmed. Reduction in CO emissions of approximately 50% over previous flame stabilizer designs was achieved.

Case History CO and VOC Emissions

Current Design

The NOx emissions in duct burner systems are relatively low in comparison to ambient air fired burners. This is partially due to lower thermal NOx generation as a result of lower flame temperatures when firing with TEG as an oxidizer. Computational using only the extended Zeldovich mechanism, suggest that NOx emissions from duct burner systems should be lower than experimental data indicates. These computational results indicate that the ratio of prompt NOx to thermal NOx is higher in duct burner systems. A common passive method of total NOx reduction in duct burner systems is the utilization of re-burn. Re-burn is the concept of reducing incoming NOx (from the TEG) by reverse reactions from NOx to N2 in UHC rich flames. These reverse reaction rates are kinetically slow, therefore the limitation of re-burn NOx reduction is the amount of residence time in the re-burn zone. For duct burners the re-burn zone is the flame zone. Coen's ***PowerPlus*** duct burner has significant increases in residence time in the flame zone and as a consequence NOx reduction via re-burn.

The end result is our new ***PowerPlus*** duct burner. It produces the lowest NOx, CO, UBHC's and VOC emissions possible under any turbine exhaust condition!

For more information about this product, talk to your nearest Coen Sales Representative.

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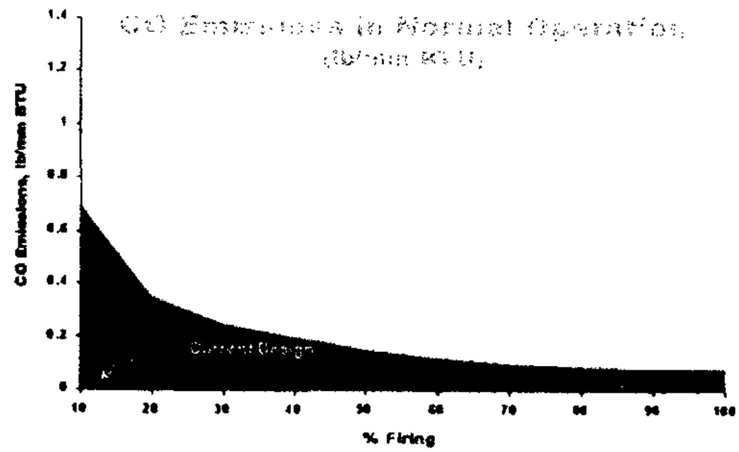
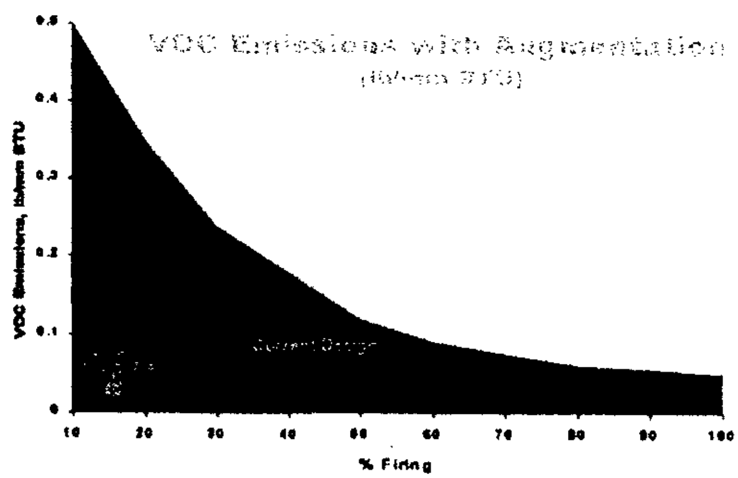
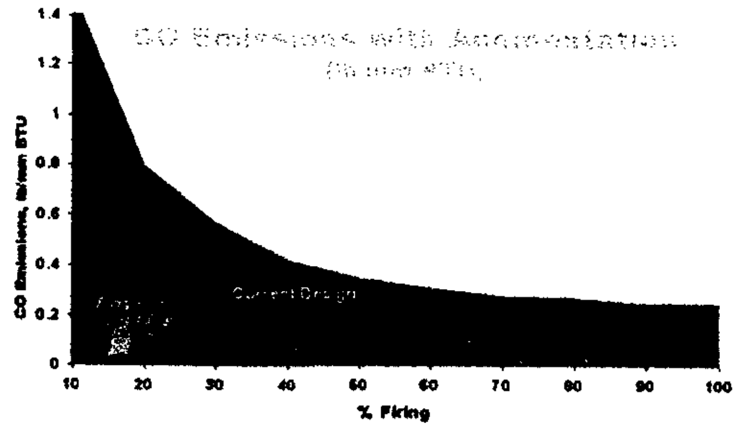
CO & VOC Emissions



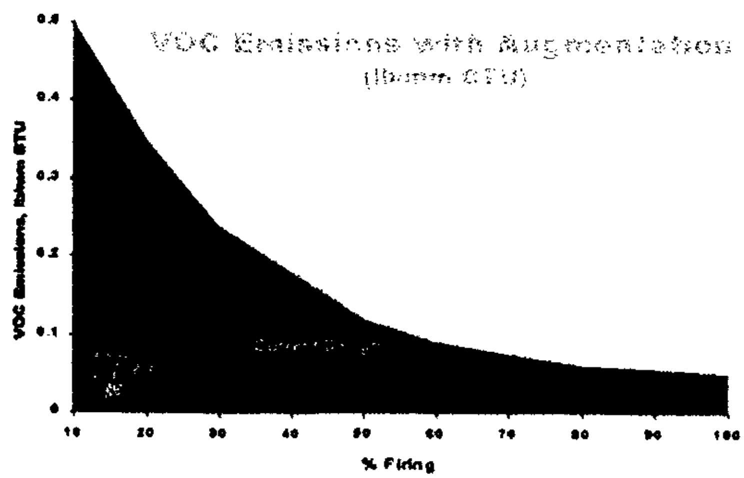
*Guaranteed Lowest Emissions ... **Under Any Condition!***



*Minimum 50% Reduction in CO and VOCs...**in any Mode!***



***No Augmenting Air!** No Increase in NOx! No Increase in Burner Pressure Drop!*



*Low Emissions in GT Power Augmentation Mode...**with No Supplemental Air!***

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ATTACHMENT B

FPL MARTIN PLANT Distillate fuel
BASELOAD FOGGED TO 95% RH FROM 60 DEG-F
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	50.	60.	70.	80.
Evap. Cooler Status		None	On	On	On
Evap. Cooler Effectiveness	%		95	95	95
Fuel Type		Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78	1.78
Output	kW	185,300.	184,000.	180,200.	175,800.
Heat Rate (LHV)	Btu/kWh	9,945.	9,940.	9,955.	9,985.
Heat Cons. (LHV) X 10^6	Btu/h	1,842.8	1,829.	1,793.9	1,755.4
Auxiliary Power	kW	1,390	1,390	1,390	1,390
Output Net	kW	183,910.	182,610.	178,810.	174,410.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,020.	10,030.	10,060.
Exhaust Flow X 10^3	lb/h	3750.	3719.	3649.	3573.
Exhaust Temp.	Deg F.	1089.	1093.	1102.	1111.
Exhaust Heat (LHV) X 10^6	Btu/h	1016.5	1012.5	996.4	980.4
Water Flow	lb/h	124,260.	119,340.	114,320.	107,900.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.
NOx AS NO2	lb/h	325.	322.	316.	309.
CO	ppmvd	20.	20.	20.	20.
CO	lb/h	66.	65.	64.	62.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	15.	15.	14.	14.
VOC	ppmvw	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.5	7.	7.
SO2	ppmvw	11.0	11.0	11.0	11.0
SO2	lb/h	95.0	94.0	93.0	91.0
SO3	ppmvw	1.0	1.0	1.0	1.0
SO3	lb/h	7.0	7.0	6.0	6.0
Sulfur Mist	lb/h	10.0	10.0	10.0	10.0
Particulates	lb/h	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.85	0.86	0.85
Nitrogen	71.47	71.19	70.94	70.63
Oxygen	11.10	11.04	10.98	10.92
Carbon Dioxide	5.57	5.56	5.55	5.54
Water	11.01	11.37	11.68	12.07

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60

Application	7FH2 Hydrogen-Cooled Generator
Combustion System	9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:41 FPL Martin dis BL fogg rge

FPL MARTIN PLANT DISTILLATE FUEL GUARANTEE POINT
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Output	kW	172,200.
Heat Rate (LHV)	Btu/kWh	10,090.
Heat Cons. (LHV) X 10^6	Btu/h	1,737.5
Auxiliary Power	kW	1,390
Output Net	kW	170,810.
Heat Rate (LHV) Net	Btu/kWh	10,170.
Exhaust Flow X 10^3	lb/h	3552.
Exhaust Temp.	Deg F.	1113.
Exhaust Heat (LHV) X 10^6	Btu/h	971.0
Water Flow	lb/h	111,950.
EMISSIONS		
NOx	ppmvd @ 15% O2	42.
NOx AS NO2	lb/h	307.
CO	ppmvd	20.
CO	lb/h	62.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	3.5
VOC	lb/h	7.
SO2	ppmvw	11.0
SO2	lb/h	90.0
SO3	ppmvw	1.0
SO3	lb/h	6.0
Sulfur Mist	lb/h	9.0
Particulates	lb/h	17.0
EXHAUST ANALYSIS	% VOL.	
Argon		0.85
Nitrogen		70.94
Oxygen		11.00
Carbon Dioxide		5.54
Water		11.68
SITE CONDITIONS		
Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Liquid Fuel, H/C Ratio Of 1.82
Fuel LHV	Btu/lb	18387 @ 60 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.

FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: N 72410996

HENRYCO 01/28/2000 17:26FPL Martin dis BL guar.dat

FPL Martin Plant Distillate Fuel Base Load over ambient range
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	0.	35.	59.	75.	95.
Ambient Relative Humid.	%	2.0	20.0	60.0	60.0	50.0
Fuel Type		Liquid	Liquid	Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60	60	60
Liquid Fuel H/C Ratio		1.82	1.78	1.78	1.78	1.78
Output	kW	192,400.	190,500.	181,800.	173,900.	160,600.
Heat Rate (LHV)	Btu/kWh	10,110.	9,945.	9,960.	10,020.	10,190.
Heat Cons. (LHV) X 10^6	Btu/h	1,945.2	1,894.5	1,810.7	1,742.5	1,636.5
Auxiliary Power	kW	1,390	1,390	1,390	1,390	1,390
Output Net	kW	191,010.	189,110.	180,410.	172,510.	159,210.
Heat Rate (LHV) Net	Btu/kWh	10,180.	10,020.	10,040.	10,100.	10,280.
Exhaust Flow X 10^3	lb/h	3928.	3862.	3683.	3552.	3376.
Exhaust Temp.	Deg F.	1066.	1074.	1098.	1113.	1131.
Exhaust Heat (LHV) X 10^6	Btu/h	1082.9	1042.6	1000.7	970.1	926.3
Water Flow	lb/h	134,140.	130,930.	120,720.	111,950.	98,570.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.	42.
NOx AS NO2	lb/h	343.	334.	319.	307.	289.
CO	ppmvd	20.	20.	20.	20.	20.
CO	lb/h	69.	68.	65.	62.	59.
UHC	ppmvw	7.	7.	7.	7.	7.
UHC	lb/h	15.	15.	15.	14.	13.
VOC	ppmvw	3.5	3.5	3.5	3.5	3.5
VOC	lb/h	7.5	7.5	7.5	7.	6.5
SO2	ppmvw	12.0	11.0	11.0	11.0	11.0
SO2	lb/h	101.0	98.0	94.0	90.0	85.0
SO3	ppmvw	0.0	1.0	1.0	1.0	1.0
SO3	lb/h	6.0	6.0	6.0	6.0	5.0
Sulfur Mist	lb/h	11.0	10.0	10.0	9.0	9.0
Particulates	lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.86	0.86	0.85	0.85
Nitrogen	71.84	71.79	71.31	70.94	70.52
Oxygen	11.13	11.19	11.06	11.00	11.00
Carbon Dioxide	5.62	5.56	5.56	5.54	5.46
Water	10.56	10.60	11.21	11.68	12.18

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:58 FPL Martin dis BL rge

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 0 DEGF AND NEGLEGIBLE REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	192,400.	144,300.	96,200.
Heat Rate (LHV)	Btu/kWh	10,110.	10,680.	12,630.
Heat Cons. (LHV) X 10^6	Btu/h	1,945.2	1,541.1	1,215.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	191,010.	142,910.	94,810.
Heat Rate (LHV) Net	Btu/kWh	10,180.	10,780.	12,820.
Exhaust Flow X 10^3	lb/h	3928.	3076.	2521.
Exhaust Temp.	Deg F.	1066.	1107.	1154.
Exhaust Heat (LHV) X 10^6	Btu/h	1082.9	895.2	772.8
Water Flow	lb/h	134,140.	96,540.	67,700.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	343.	269.	210.
CO	ppmvd	20.	25.	36.
CO	lb/h	69.	69.	81.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	12.0	12.0	11.0
SO2	lb/h	101.0	80.0	63.0
SO3	ppmvw	<1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	4.0
Sulfur Mist	lb/h	11.0	8.0	7.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87
Nitrogen	71.84	72.17	72.81
Oxygen	11.13	11.19	11.73
Carbon Dioxide	5.62	5.64	5.38
Water	10.56	10.15	9.21

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	2
Application		7FH2 Hydrogen-Cooled Generator

Combustion System	9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:59 FPL Martin dis load rge 0

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	190,500.	142,900.	95,200.
Heat Rate (LHV)	Btu/kWh	9,945.	10,550.	12,500.
Heat Cons. (LHV) X 10^6	Btu/h	1,894.5	1,507.6	1,190.
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	189,110.	141,510.	93,810.
Heat Rate (LHV) Net	Btu/kWh	10,020.	10,650.	12,690.
Exhaust Flow X 10^3	lb/h	3862.	3024.	2487.
Exhaust Temp.	Deg F.	1074.	1121.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	1042.6	868.7	752.4
Water Flow	lb/h	130,930.	94,620.	66,770.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	334.	263.	206.
CO	ppmvd	20.	24.	35.
CO	lb/h	68.	65.	77.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	98.0	78.0	61.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	5.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.87
Nitrogen	71.79	72.10	72.73
Oxygen	11.19	11.22	11.76
Carbon Dioxide	5.56	5.60	5.35
Water	10.60	10.23	9.29

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:00FPL Martin dis load rge 35

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	181,800.	136,400.	90,900.
Heat Rate (LHV)	Btu/kWh	9,960.	10,620.	12,670.
Heat Cons. (LHV) X 10^6	Btu/h	1,810.7	1,448.6	1,151.7
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	180,410.	135,010.	89,510.
Heat Rate (LHV) Net	Btu/kWh	10,040.	10,730.	12,870.
Exhaust Flow X 10^3	lb/h	3683.	2936.	2435.
Exhaust Temp.	Deg F.	1098.	1137.	1182.
Exhaust Heat (LHV) X 10^6	Btu/h	1000.7	841.4	734.9
Water Flow	lb/h	120,720.	86,500.	61,390.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	319.	253.	199.
CO	ppmvd	20.	24.	34.
CO	lb/h	65.	61.	73.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.5	6.	5.
SO2	ppmvw	11.0	12.0	11.0
SO2	lb/h	94.0	75.0	60.0
SO3	ppmvw	1.0	<1.0	1.0
SO3	lb/h	6.0	5.0	3.0
Sulfur Mist	lb/h	10.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.86	0.86	0.88
Nitrogen	71.31	71.72	72.33
Oxygen	11.06	11.21	11.76
Carbon Dioxide	5.56	5.54	5.27
Water	11.21	10.68	9.77

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator

Combustion System 9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:01 FPL Martin dis load rge 59

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	75.	75.	75.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	173,900.	130,500.	87,000.
Heat Rate (LHV)	Btu/kWh	10,020.	10,750.	12,860.
Heat Cons. (LHV) X 10^6	Btu/h	1,742.5	1,402.9	1,118.8
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	172,510.	129,110.	85,610.
Heat Rate (LHV) Net	Btu/kWh	10,100.	10,870.	13,070.
Exhaust Flow X 10^3	lb/h	3552.	2871.	2389.
Exhaust Temp.	Deg F.	1113.	1149.	1193.
Exhaust Heat (LHV) X 10^6	Btu/h	970.1	823.5	721.0
Water Flow	lb/h	111,950.	80,050.	56,630.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	307.	245.	193.
CO	ppmvd	20.	23.	34.
CO	lb/h	62.	59.	71.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	7.	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	90.0	72.0	58.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	6.0	5.0	4.0
Sulfur Mist	lb/h	9.0	8.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.86
Nitrogen	70.94	71.40	72.00
Oxygen	11.00	11.22	11.77
Carbon Dioxide	5.54	5.47	5.21
Water	11.68	11.06	10.17

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:02 FPL Martin dis load rge 75

FPL MARTIN PLANT Distillate Fuel
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Liquid	Liquid	Liquid
Fuel LHV	Btu/lb	18,387	18,387	18,387
Fuel Temperature	Deg F	60	60	60
Liquid Fuel H/C Ratio		1.78	1.78	1.78
Output	kW	160,600.	120,500.	80,300.
Heat Rate (LHV)	Btu/kWh	10,190.	11,010.	13,220.
Heat Cons. (LHV) X 10^6	Btu/h	1,636.5	1,326.7	1,061.6
Auxiliary Power	kW	1,390	1,390	1,390
Output Net	kW	159,210.	119,110.	78,910.
Heat Rate (LHV) Net	Btu/kWh	10,280.	11,140.	13,450.
Exhaust Flow X 10^3	lb/h	3376.	2758.	2323.
Exhaust Temp.	Deg F.	1131.	1166.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	926.3	793.5	695.9
Water Flow	lb/h	98,570.	70,300.	49,100.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	289.	232.	183.
CO	ppmvd	20.	24.	36.
CO	lb/h	59.	57.	74.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	6.5	5.5	4.5
SO2	ppmvw	11.0	11.0	11.0
SO2	lb/h	85.0	69.0	55.0
SO3	ppmvw	1.0	1.0	<1.0
SO3	lb/h	5.0	4.0	3.0
Sulfur Mist	lb/h	9.0	7.0	6.0
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.87
Nitrogen	70.52	70.99	71.61
Oxygen	11.00	11.25	11.86
Carbon Dioxide	5.46	5.38	5.07
Water	12.18	11.54	10.60

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Liquid Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.
Sulfur Emissions Based On 0.05 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:03 FPL Martin dis load rge 95

FPL MARTIN PLANT Gas Fuel
BASELOAD FOGGED 95% RH FROM 60 DEG F
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE	BASE	BASE
Ambient Temp.	Deg F.	50.	60.	70.	80.
Evap. Cooler Status		None	On	On	On
Evap. Cooler Effectiveness	%		95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290	290
Output	kW	177,200.	176,000.	171,700.	166,700.
Heat Rate (LHV)	Btu/kWh	9,215.	9,235.	9,280.	9,350.
Heat Cons. (LHV) X 10^6	Btu/h	1,632.9	1,625.4	1,593.4	1,558.6
Auxiliary Power	kW	560	560	560	560
Output Net	kW	176,640.	175,440.	171,140.	166,140.
Heat Rate (LHV) Net	Btu/kWh	9,240.	9,260.	9,310.	9,380.
Exhaust Flow X 10^3	lb/h	3602.	3577.	3512.	3444.
Exhaust Temp.	Deg F.	1110.	1113.	1119.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	969.0	965.8	949.6	933.2
EMISSIONS					
NOx	ppmvd @ 15% O2	9.	9.	9.	9.
NOx AS NO2	lb/h	60.	60.	58.	57.
CO	ppmvd	9.	9.	9.	9.
CO	lb/h	29.	29.	28.	28.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	14.	14.	14.	14.
VOC	ppmvw	1.4	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.8	2.8
Particulates	lb/h	9.0	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.				
Argon		0.88	0.89	0.88	0.88
Nitrogen		74.62	74.19	73.84	73.38
Oxygen		12.47	12.35	12.28	12.19
Carbon Dioxide		3.89	3.89	3.87	3.86
Water		8.14	8.69	9.13	9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 18:39 FPL Martin gas BL fogg rge

FPL Martin Plant Gas Fuel Guarantee Point
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	75.
Output	kW	162,100.
Heat Rate (LHV)	Btu/kWh	9,440.
Heat Cons. (LHV) X 10^6	Btu/h	1,530.2
Auxiliary Power	kW	560
Output Net	kW	161,540.
Heat Rate (LHV) Net	Btu/kWh	9,470.
Exhaust Flow X 10^3	lb/h	3418.
Exhaust Temp.	Deg F.	1128.
Exhaust Heat (LHV) X 10^6	Btu/h	921.4

EMISSIONS

NOx	ppmvd @ 15% O2	9.
NOx AS NO2	lb/h	56.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		73.88
Oxygen		12.36
Carbon Dioxide		3.84
Water		9.04

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/28/2000 17:20FPL Martin gas BL rge

FPL MARTIN PLANT - Gas Fuel
LOAD RANGE AT 0 DEGF AND NEGLEGIBLE REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	0.	0.	0.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	189,100.	141,800.	94,600.
Heat Rate (LHV)	Btu/kWh	9,250.	9,860.	11,780.
Heat Cons. (LHV) X 10^6	Btu/h	1,749.2	1,398.1	1,114.4
Auxiliary Power	kW	560	560	560
Output Net	kW	188,540.	141,240.	94,040.
Heat Rate (LHV) Net	Btu/kWh	9,280.	9,900.	11,850.
Exhaust Flow X 10^3	lb/h	3885.	3070.	2514.
Exhaust Temp.	Deg F.	1068.	1101.	1149.
Exhaust Heat (LHV) X 10^6	Btu/h	1040.5	863.3	750.0
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	64.	51.	40.
CO	ppmvd	9.	9.	9.
CO	lb/h	32.	25.	21.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.89	0.89
Nitrogen		75.18	75.17	75.28
Oxygen		12.65	12.64	12.94
Carbon Dioxide		3.87	3.88	3.74
Water		7.41	7.42	7.15
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	3		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:34 gas BL LOAD rge 0

FPL Martin Plant Gas Fuel
LOAD RANGE AT 35 DEGF AND 20% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	35.	35.	35.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,200.	136,700.	91,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,855.	11,820.
Heat Cons. (LHV) X 10^6	Btu/h	1,673.5	1,347.2	1,076.8
Auxiliary Power	kW	560	560	560
Output Net	kW	181,640.	136,140.	90,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,900.	11,890.
Exhaust Flow X 10^3	lb/h	3706.	2979.	2456.
Exhaust Temp.	Deg F.	1095.	1122.	1168.
Exhaust Heat (LHV) X 10^6	Btu/h	991.1	831.5	725.6
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	61.	49.	39.
CO	ppmvd	9.	9.	9.
CO	lb/h	30.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	3.	2.4	2.
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.90	0.90	0.90
Nitrogen		75.07	75.10	75.21
Oxygen		12.60	12.67	12.99
Carbon Dioxide		3.88	3.85	3.70
Water		7.56	7.49	7.21
SITE CONDITIONS				
Elevation	ft.	45.0		
Site Pressure	psia	14.68		
Inlet Loss	in Water	3.0		
Exhaust Loss	in Water	5.5		
Relative Humidity	%	20		
Application		7FH2 Hydrogen-Cooled Generator		
Combustion System		9/42 DLN Combustor		

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:44 FPL Martin gas BL LOAD rge 35

FPL Martin Plant Gas Fuel
LOAD RANGE AT 59 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	173,000.	129,800.	86,500.
Heat Rate (LHV)	Btu/kWh	9,250.	10,000.	12,050.
Heat Cons. (LHV) X 10^6	Btu/h	1,600.3	1,298.	1,042.3
Auxiliary Power	kW	560	560	560
Output Net	kW	172,440.	129,240.	85,940.
Heat Rate (LHV) Net	Btu/kWh	9,280.	10,040.	12,130.
Exhaust Flow X 10^3	lb/h	3539.	2888.	2396.
Exhaust Temp.	Deg F.	1116.	1139.	1184.
Exhaust Heat (LHV) X 10^6	Btu/h	951.8	807.5	707.9
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	37.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	24.	20.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.88	0.90	0.90
Nitrogen		74.42	74.46	74.58
Oxygen		12.44	12.57	12.90
Carbon Dioxide		3.87	3.81	3.66
Water		8.39	8.27	7.97

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:45 FPL Martin gas BL LOAD rge 59

FPL Martin Plant Gas Fuel
LOAD RANGE AT 75 DEGF AND 60% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	75.	75.	75.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	163,700.	122,800.	81,900.
Heat Rate (LHV)	Btu/kWh	9,380.	10,190.	12,330.
Heat Cons. (LHV) X 10^6	Btu/h	1,535.5	1,251.3	1,009.8
Auxiliary Power	kW	560	560	560
Output Net	kW	163,140.	122,240.	81,340.
Heat Rate (LHV) Net	Btu/kWh	9,410.	10,240.	12,410.
Exhaust Flow X 10^3	lb/h	3418.	2803.	2336.
Exhaust Temp.	Deg F.	1128.	1153.	1195.
Exhaust Heat (LHV) X 10^6	Btu/h	921.1	786.3	692.2
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	56.	45.	36.
CO	ppmvd	9.	9.	9.
CO	lb/h	28.	23.	19.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.88	0.89
Nitrogen		73.88	73.93	74.04
Oxygen		12.36	12.49	12.83
Carbon Dioxide		3.84	3.78	3.62
Water		9.04	8.92	8.62

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:54 FPL Martin gas BL LOAD rge 75

FPL Martin Plant Gas Fuel
LOAD RANGE AT 95 DEGF AND 50% REL.HUMIDITY
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	95.	95.	95.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	150,300.	112,800.	75,200.
Heat Rate (LHV)	Btu/kWh	9,630.	10,550.	12,770.
Heat Cons. (LHV) X 10^6	Btu/h	1,447.4	1,190.	960.3
Auxiliary Power	kW	560	560	560
Output Net	kW	149,740.	112,240.	74,640.
Heat Rate (LHV) Net	Btu/kWh	9,670.	10,600.	12,870.
Exhaust Flow X 10^3	lb/h	3257.	2694.	2267.
Exhaust Temp.	Deg F.	1143.	1170.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	881.8	761.2	667.1
EMISSIONS				
NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	53.	43.	35.
CO	ppmvd	9.	9.	9.
CO	lb/h	26.	22.	18.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.6	2.2	1.8
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.88	0.87	0.87
Nitrogen		73.16	73.20	73.34
Oxygen		12.27	12.41	12.80
Carbon Dioxide		3.78	3.72	3.54
Water		9.92	9.80	9.45

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72410996
HENRYCO 01/28/2000 17:56 FPL Martin gas BL LOAD rge 95

FPL Martin Plant - Gas Fuel with Steam Power Augmentation
Augmentation only permitted above 59 degF
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	BASE
Ambient Temp.	Deg F.	35.	95.
Ambient Relative Humid.	%	20.0	50.0
Fuel Type		Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835
Fuel Temperature	Deg F	290	290
Output	kW	180,400.	165,100.
Heat Rate (LHV)	Btu/kWh	9,245.	9,265.
Heat Cons. (LHV) X 10^6	Btu/h	1,667.8	1,529.7
Auxiliary Power	kW	560	560
Output Net	kW	179,840.	164,540.
Heat Rate (LHV) Net	Btu/kWh	9,270.	9,300.
Exhaust Flow X 10^3	lb/h	3706.	3372.
Exhaust Temp.	Deg F.	1095.	1130.
Exhaust Heat (LHV) X 10^6	Btu/h	991.6	927.1
Steam Flow	lb/h	0.	110,260.

EMISSIONS

NOx	ppmvd @ 15% O2	9.	12
NOx AS NO2	lb/h	61.	82
CO	ppmvd	9.	15.
CO	lb/h	30.	44.
UHC	ppmvw	7.	7.
UHC	lb/h	15.	14.
VOC	ppmvw	1.4	1.4
VOC	lb/h	3.	2.8
Particulates	lb/h	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.83
Nitrogen	75.07	69.28
Oxygen	12.60	11.20
Carbon Dioxide	3.88	3.80
Water	7.56	14.89

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996
HENRYCO 01/24/2000 17:49FPL Martin gas BL stm aug 35_95.dat

FPL Martin Plant Gas fuel Steam Power Augmentation with Fogger at 80 degF

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE
Ambient Temp.	Deg F.	80.
Fogger Status		On
Fogger Effectiveness	%	95
Output	kW	165,000.
Heat Rate (LHV)	Btu/kWh	9,410.
Heat Cons. (LHV) X 10^6	Btu/h	1,552.7
Auxiliary Power	kW	560
Output Net	kW	164,440.
Heat Rate (LHV) Net	Btu/kWh	9,440.
Exhaust Flow X 10^3	lb/h	3444.
Exhaust Temp.	Deg F.	1125.
Exhaust Heat (LHV) X 10^6	Btu/h	933.1

EMISSIONS

NOx	ppmvd @ 15% O2	12
NOx AS NO2	lb/h	76.
CO	ppmvd	15
CO	lb/h	47.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.88
Nitrogen		73.38
Oxygen		12.19
Carbon Dioxide		3.86
Water		9.70

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: N 72410996

HENRYCO 01/24/2000 17:58FPL Martin gas BL stm aug 80 fogg.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	0.
Output	kW	196,900.
Heat Rate (LHV)	Btu/kWh	9,075.
Heat Cons. (LHV) X 10^6	Btu/h	1,786.9
Auxiliary Power	kW	560
Output Net	kW	196,340.
Heat Rate (LHV) Net	Btu/kWh	9,100.
Exhaust Flow X 10^3	lb/h	3927.
Exhaust Temp.	Deg F.	1073.
Exhaust Heat (LHV) X 10^6	Btu/h	1049.8

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	111.
CO	ppmvd	9.
CO	lb/h	32.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90
Nitrogen	75.11
Oxygen	12.45
Carbon Dioxide	3.96
Water	7.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	1
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 11 72411298
HENRYCO 01/28/2000 19:41 FPL MARTIN PLANT Peak gas 0 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	35.
Output	kW	190,300.
Heat Rate (LHV)	Btu/kWh	9,080.
Heat Cons. (LHV) X 10^6	Btu/h	1,727.9
Auxiliary Power	kW	560
Output Net	kW	189,740.
Heat Rate (LHV) Net	Btu/kWh	9,110.
Exhaust Flow X 10^3	lb/h	3713.
Exhaust Temp.	Deg F.	1109.
Exhaust Heat (LHV) X 10^6	Btu/h	1015.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	105.
CO	ppmvd	9.
CO	lb/h	30.
UHC	ppmvw	7.
UHC	lb/h	15.
VOC	ppmvw	1.4
VOC	lb/h	3.
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		75.00
Oxygen		12.39
Carbon Dioxide		3.98
Water		7.74

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	20
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:49 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	59.
Output	kW	179,500.
Heat Rate (LHV)	Btu/kWh	9,225.
Heat Cons. (LHV) X 10^6	Btu/h	1,655.9
Auxiliary Power	kW	560
Output Net	kW	178,940.
Heat Rate (LHV) Net	Btu/kWh	9,250.
Exhaust Flow X 10^3	lb/h	3541.
Exhaust Temp.	Deg F.	1139.
Exhaust Heat (LHV) X 10^6	Btu/h	983.3

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	101.
CO	ppmvd	9.
CO	lb/h	29.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89
Nitrogen	74.34
Oxygen	12.20
Carbon Dioxide	3.98
Water	8.59

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:46 FPL MARTIN PLANT Peak gas 59 dry.dat

FPL MARTIN PLANT Peak Firing
ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	75.
Output	kW	169,500.
Heat Rate (LHV)	Btu/kWh	9,370.
Heat Cons. (LHV) X 10^6	Btu/h	1,588.2
Auxiliary Power	kW	560
Output Net	kW	168,940.
Heat Rate (LHV) Net	Btu/kWh	9,400.
Exhaust Flow X 10^3	lb/h	3413.
Exhaust Temp.	Deg F.	1152.
Exhaust Heat (LHV) X 10^6	Btu/h	952.2

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	97.
CO	ppmvd	9.
CO	lb/h	28.
UHC	ppmvw	7.
UHC	lb/h	14.
VOC	ppmvw	1.4
VOC	lb/h	2.8
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.89
Nitrogen		73.80
Oxygen		12.12
Carbon Dioxide		3.95
Water		9.25

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 75 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK
Ambient Temp.	Deg F.	95.
Output	kW	156,100.
Heat Rate (LHV)	Btu/kWh	9,595.
Heat Cons. (LHV) X 10^6	Btu/h	1,497.8
Auxiliary Power	kW	560
Output Net	kW	155,540.
Heat Rate (LHV) Net	Btu/kWh	9,630.
Exhaust Flow X 10^3	lb/h	3238.
Exhaust Temp.	Deg F.	1172.
Exhaust Heat (LHV) X 10^6	Btu/h	910.7

EMISSIONS

NOx	ppmvd @ 15% O2	15.
NOx AS NO2	lb/h	91.
CO	ppmvd	9.
CO	lb/h	26.
UHC	ppmvw	7.
UHC	lb/h	13.
VOC	ppmvw	1.4
VOC	lb/h	2.6
Particulates	lb/h	9.0

EXHAUST ANALYSIS	% VOL.	
Argon		0.88
Nitrogen		73.06
Oxygen		11.99
Carbon Dioxide		3.91
Water		10.16

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	50
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20835 @ 290 °F
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:47 FPL MARTIN PLANT Peak gas 95 dry.dat

FPL MARTIN PLANT Peak Firing

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK	PEAK	PEAK
Ambient Temp.	Deg F.	60.	70.	80.
Evap. Cooler Status		On	On	On
Evap. Cooler Effectiveness	%	95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	182,600.	177,900.	172,500.
Heat Rate (LHV)	Btu/kWh	9,190.	9,260.	9,345.
Heat Cons. (LHV) X 10^6	Btu/h	1,678.1	1,647.4	1,612.
Auxiliary Power	kW	560	560	560
Output Net	kW	182,040.	177,340.	171,940.
Heat Rate (LHV) Net	Btu/kWh	9,220.	9,290.	9,380.
Exhaust Flow X 10^3	lb/h	3581.	3513.	3441.
Exhaust Temp.	Deg F.	1131.	1141.	1149.
Exhaust Heat (LHV) X 10^6	Btu/h	994.1	980.5	964.9

EMISSIONS

NOx	ppmvd @ 15% O2	15.	15.	15.
NOx AS NO2	lb/h	103.	100.	99.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	28.	28.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	14.	14.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.8
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.87	0.88
Nitrogen	74.11	73.76	73.29
Oxygen	12.14	12.05	11.95
Carbon Dioxide	3.98	3.98	3.97
Water	8.88	9.34	9.91

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.

IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:57 FPL MARTIN PLANT Peak gas fogg 607080.dat

FPL MARTIN PLANT Peak Firing with FPLE Fogger on

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		PEAK	PEAK	PEAK
Ambient Temp.	Deg F.	59.	75.	95.
Ambient Relative Humid.	%	60.	60.	50.
Fogger Status		On	On	On
Fogger Effectiveness	%	95	95	95
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,835	20,835	20,835
Fuel Temperature	Deg F	290	290	290
Output	kW	183,000.	175,200.	166,100.
Heat Rate (LHV)	Btu/kWh	9,185.	9,300.	9,450.
Heat Cons. (LHV) X 10^6	Btu/h	1,680.9	1,629.4	1,569.6
Auxiliary Power	kW	560	560	560
Output Net	kW	182,440.	174,640.	165,540.
Heat Rate (LHV) Net	Btu/kWh	9,210.	9,330.	9,480.
Exhaust Flow X 10^3	lb/h	3588.	3478.	3356.
Exhaust Temp.	Deg F.	1130.	1145.	1158.
Exhaust Heat (LHV) X 10^6	Btu/h	995.4	972.4	945.9
EMISSIONS				
NOx	ppmvd @ 15% O2	15.	15.	15.
NOx AS NO2	lb/h	103.	99.	96.
CO	ppmvd	9.	9.	9.
CO	lb/h	29.	28.	27.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	14.	13.
VOC	ppmvw	1.4	1.4	1.4
VOC	lb/h	2.8	2.8	2.6
Particulates	lb/h	9.0	9.0	9.0
EXHAUST ANALYSIS	% VOL.			
Argon		0.89	0.87	0.87
Nitrogen		74.14	73.54	72.64
Oxygen		12.15	12.01	11.81
Carbon Dioxide		3.98	3.97	3.95
Water		8.84	9.61	10.73

SITE CONDITIONS

Elevation	ft.	45.0
Site Pressure	psia	14.68
Inlet Loss	in Water	3.0
Exhaust Loss	in Water	5.5
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.0002 WT% Sulfur Content in the Fuel.
IPS- 90973 version code- 2 . 0 . 1 Opt: 9 72411298
HENRYCO 01/28/2000 19:30 FPL MARTIN PLANT Peak gas fogg.dat

ATTACHMENT C

DUCT FIRING

Table A-1C Flue Gas Composition with CT and Duct Firing

lb/hr fuel (mmBtu/hr) -HHV	550	Air (lb/cf) Oxygen	(1)	0.167396	88861.4
Heating value (btu/cf)	1036	Air (lb/cf) Nitrogen	(1)	0.550712	
Fuel Flow (cf/hr)	530845.6	Prod (lb/cf) CO2	(1)	0.115072	61085.5
Fuel Flow (lb/hr)	22720.19	Prod (lb/cf) Water	(1)	0.093955	49875.6

Molecular Weight Calculation at 80 °F

Compound	Molecular Weight	Volume (Fraction)	Molecular Weight (Percent)
Argon	39.95	0.009	0.35
Nitrogen	28.01	0.734	20.56
Oxygen	32.00	0.122	3.90
Carbon Dioxide	44.01	0.039	1.70
Water	18.02	0.097	1.75
Carbon Monoxide	28.01	0	0.00
Nitrogen Dioxide	30.00	0	0.00
TOTAL		1.0001	28.25

Power Augmentation

	mass flow CT (lb/hr)	mass flow DB (lb/hr)	mass flow CT + DB (lb/hr)	volume flow (cf/hr)	(% flow)	Molecular Weight
Argon	42,849.8	0.0	42,849.8	1,254,979	0.009	0.37
Nitrogen	2,505,619.2	0.0	2,505,619.2	104,648,117	0.766	21.45
Oxygen	475,454.5	-88,861.4	386,593.0	14,135,218	0.103	3.31
Carbon Dioxide	207,066.4	61,085.5	268,151.9	7,128,730	0.052	2.30
Water	213,010.1	49,875.6	262,885.7	17,072,307	0.125	2.25
Total	3,444,000.0	22,099.6	3,466,099.6	144,239,351 acf/hr 2,403,989 acfm		29.68 MW

DUCT FIRING

Table A-1C Flue Gas Composition with CT and Duct Firing

lb/hr fuel (mmBtu/hr) -HHV	550	Air (lb/cf) Oxygen	(1)	0.167396	88861.4
Heating value (btu/cf)	1036	Air (lb/cf) Nitrogen	(1)	0.550712	
Fuel Flow (cf/hr)	530845.6	Prod (lb/cf) CO2	(1)	0.115072	61085.5
Fuel Flow (lb/hr)	22720.2	Prod (lb/cf) Water	(1)	0.093955	49875.6

Molecular Weight Calculation at 95 °F

Compound	Molecular Weight	Volume (Fraction)	Molecular Weight (Percent)
Argon	39.95	0.0088	0.35
Nitrogen	28.01	0.7316	20.49
Oxygen	32.00	0.1227	3.93
Carbon Dioxide	44.01	0.0378	1.66
Water	18.02	0.0992	1.79
Carbon Monoxide	28.01	0	0.00
Nitrogen Dioxide	30.00	0	0.00
TOTAL		1.0001	28.22

Case 1
based on Case 2 95 °F

	mass flow CT (lb/hr)	mass flow DB (lb/hr)	mass flow CT + DB (lb/hr)	volume flow (cf/hr)	(% flow)	Molecular Weight
Argon	40,568.6	0.0	40,568.6	1,188,166	0.009	0.35
Nitrogen	2,365,111.9	0.0	2,365,111.9	98,779,781	0.723	20.25
Oxygen	453,096.2	-88,861.4	364,234.8	13,317,721	0.097	3.12
Carbon Dioxide	191,979.5	61,085.5	253,065.0	6,727,649	0.049	2.17
Water	206,243.7	49,875.6	256,119.3	16,632,886	0.122	2.19
Total	3,257,000.0	22,099.6	3,279,099.6	136,646,203 acf/hr 2,277,437 acfm		28.08 MW

ATTACHMENT D

Data Input-Manatee

NOx		
MW Capacity Net Gas @ 59 °F	172.44	
Heat Input CT Gas @ 59 °F	1,776.30	
Heat Rate (Btu/kW-hr)	10,301	<-calculated
Mass Flow CT Gas @ 59 °F	3,556,680	
Maximum CT Mass Flow	3,728,100	
Oxygen	12.44%	
Moisture	8.39%	
DB Heat Input	550	
Uncontrolled Emissions.		
NOx-Gas (lb/hr)	58.70	
NOx-Gas & DB (lb/hr)	113.70	
NOx-PA/DB or Oil (lb/hr)	319.2	
Controlled Emissions:		<-calculated
NOx-Gas (lb/hr; 3.5 ppm)	22.83	<-calculated
NOx-Gas & DB (lb/hr, 3.5 ppm)	33.08	<-calculated
NOx-PA/DB or Oil (lb/hr)	91.2	<-calculated
NOx-Gas (lb/hr; 2.5 ppm)	16.31	<-calculated
NOx-Gas & DB (lb/hr; 2.5 ppm)	23.63	
NOx-PA/DB or Oil (lb/hr)	91.2	<-calculated
NOx-Gas (lb/hr, 2.0 ppm)	13.04	<-calculated
NOx-Gas & DB (lb/hr; 2.0 ppm)	18.90	
NOx-PA/DB or Oil (lb/hr)		
Gas CT Only Hours	5880	<-calculated
Gas & DB Hours	2880	
PA/DB or Oil Hours	0	
SO_2 (TPY)	47.8	
SCR System Cost (3.5 ppmvd)	$1,040,044	<-calculated
SCR Catalyst	$597,452	<-calculated
NH_3 Slip	9	
SCR System Cost (2.5 ppmvd)	$1,391,170	<-calculated
SCR Catalyst	$824,106	<-calculated
NH_3 Slip	9	
SCR System Cost (2.0 ppmvd)	$1,553,048	<-calculated
SCR Catalyst	$1,076,734	<-calculated
NH_3 Slip	9	
$SCONO_x$ System		
System Cost	$14,750,000	
Steam (lbs/hr)	17,795	
Gas (lb/hr)	80	
CO		
Uncontrolled Emissions:		
CO-Gas (lb/hr)	27.5	
CO-Gas & DB (lb/hr)	71.5	71.5 check
CO-PA/DB or Oil (lb/hr)	64.7	
CO-Gas (ppmvd)	9	
CO-Gas & DB (ppmvd)	22.9	
CO-PA/DB or Oil (ppmvd)	20	
OC System Cost	$758,000	<-calculated
OC Catalyst	$659,000	<-calculated
VOC		
VOC-Gas (lb/hr)	2.74	
VOC-Gas & DB (lb/hr)	11.54	
VOC-PA/DB or Oil (lb/hr)	7.28	

SCR Cost Data

Options	SCR System	SCR Catalyst	Turbine	CT NOx Rate Gas-In	NOx Rate Gas-Out	NOx Rate Oil	Mass Flow	NH_3 Slip	Pressure Drop	Source	Date
SCR System Cost	$1,583,000	$1,097,500	GE 7FA	9	2	N/A	3,800,000	10	2.2	Engelhard	12/19/00
(minus Cat cost)	$485,500										
SCR System Cost	$1,418,000	$840,000	GE 7FA	9	2.5	N/A	3,800,000	10		Engelhard	12/19/00
(minus Cat cost)	$578,000										
SCR System Cost	$1,088,000	$625,000	GE 7FA	9	3.5	18.4	3,900,000	9	2.1	Engelhard	12/13/99
(minus Cat cost)	$463,000										
SCR System Cost	$1,249,000	$783,000	GE 7FA	9	3.5	18.4	3,900,000	5	2.4	Engelhard	12/13/99
(minus Cat cost)	$466,000										
SCR System Cost	$928,000	$469,000	GE 7FA	9	4.5	23.7	3,900,000	9	1.8	Engelhard	12/13/99
(minus Cat cost)	$459,000										
SCR System Cost	$1,088,000	$625,000	GE 7FA	9	4.5	23.7	3,900,000	5	2.1	Engelhard	12/13/99
	$463,000										

Standardized Cost Data

NOx Rate Gas-Out	Mass Flow (lb/hr)	NH_3 Slip (ppm)	System Cost	Catalyst Cost	System Cost Standardized to Mass Flow ($/(lb/hr))	Catalyst Cost Standardized to Mass Flow ($/(lb/hr))
2.0	3,800,000	10	$1,583,000	$1,097,500	0.417	0.289
2.5	3,800,000	10	$1,418,000	$840,000	0.373	0.221
3.5	3,900,000	9	$1,088,000	$625,000	0.279	0.160
4.5	3,900,000	9	$928,000	$469,000	0.238	0.120

Project Specific Cost Data

Project Maximum Mass Flow(lb/hr)	NOx Rate Gas-Out	NH_3 Slip (ppm)	System Cost ($)	Cat Cost ($)
3,728,100	2.0	9	1553048	1076734
3,728,100	2.5	9	1391170	824106
3,728,100	3.5	9	1040044	597452
3,728,100	4.5	9	887097	448328

Pressure Drop Data

NOx Rate Gas-Out	NH_3 Slip (ppm)	Pressure Drop (inches water)	Data Source
4.5	9	1.80	Vendor
3.5	9	2.10	Vendor
2.5	9	2.45	Calculated*
2.0	9	2.65	Calculated*

* Based on percent change of pressure drop from 4.5 to 3.5 ppm system

Project Specific Incremental Cost Effectiveness

Base NOx (ppm)	Target NOx (ppm)	NOx Removed Base (lb/hr)	NOx Removed Target (lb/hr)	NOx Removed (Target-Base) (lb/hr)	Total Annualized SCR Cost Base ($)	Total Annualized SCR Cost Target ($)	Total Annualized SCR Cost (Target-Base) ($)	Incremental Cost Effectiveness ($/(Ton NOx Removed))
9.0	3.5	0	221.56	221.56	0	$1,080,934	$1,080,934	$4,878.80
3.5	2.5	221.56	254.34	32.79	$1,080,934	$1,323,432	$242,498	$7,396.54
2.5	2.0	254.34	270.74	16.39	$1,323,432	$1,521,191	$197,759	$12,063.90

$SCONO_x$ Cost Data

	GE 7FA	SW 501F	SW 501G
System Cost	$14,750,000	$16,712,000	$20,711,700
Steam (lbs/hr)	17,795	18,184	22,285
Gas (lb/hr)	80	81	100
Back Pressure	3.4	3.1	4.9

Oxidation Catalyst Cost Data

Options	OC System	OC Catalyst	Turbine	CT CO ppm Gas-In	CO ppm Gas-Out	Mass Flow	NH_3 Slip	Pressure Drop	Source	Date
OC System Cost	$758,000	$659,000	GE 7FA	9	0.9	3,900,000	9	2.1	Engelhard	12/13/99
OC System Cost	$773,000	$674,000	SW 501F	25	2.5	3,600,000	9	2.5	Engelhard	1/12/00

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

GE 7FA – Simple Cycle

ASSUMED AMBIENT	59	59	59	59
GIVEN TURBINE EXHAUST TEMPERATURE, F	1,100	1,100	1,100	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000	3,900,000	4,080,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63	75.23	71.63
O2	12.61	11.04	12.61	11.04
CO2	3.63	5.20	3.63	5.20
H2O	7.60	11.20	7.60	11.20
Ar	0.93	0.93	0.93	0.93
AMBIENT AIR FLOW, lb/hr	332,949	348,316	332,949	348,316
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	4,232,949	4,428,316	4,232,949	4,428,316
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.70	72.37	75.70	72.37
O2	13.09	11.64	13.09	11.64
CO2	3.35	4.80	3.35	4.80
H2O	7.01	10.33	7.01	10.33
Ar	0.86	0.86	0.86	0.86
CALCULATED AIR + GAS MOL. WT.	28.48	28.32	28.48	28.32
GIVEN: TURBINE CO, ppmvd	9.0	20.0	9.0	20.0
CALC.: TURBINE CO, lb/hr	31.9	71.7	31.9	71.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	9.0	42.0	9.0	42.0
CALC.: TURBINE NOx, lb/hr	64.5	355.2	64.5	355.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE	7.1	13.6	7.1	13.6
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE	8.8	41.0	8.8	41.0
FLUE GAS TEMP. @ SCR CATALYST, F	1,025	1,025	1,025	1,025
DESIGN REQUIREMENTS				
CO CATALYST CO CONVERSION, %	90%	90%	90%	90%
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	ADVISE	3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12	5	12
SCR PRESSURE DROP, 4.0"WG – Nom.				
GUARANTEED PERFORMANCE DATA				
CO CONVERSION - % Min.	90.0%	90.0%	90.0%	90.0%
CO OUT, ppmvd @ 15% O2	0.7	1.4	0.7	1.4
CO OUT, lb/hr	3.2	7.2	3.2	7.2
CO PRESSURE DROP	2.2	2.4	2.2	2.4
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%	61.1%	61.1%
NOx OUT, lb/hr – Max.	25.1	138.1	25.1	138.1
NOx OUT, ppmvd@15%O2 – Max.	3.4	16.0	3.4	16.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	139	424	101	424
NH3 SLIP, ppmvd@15%O2 – Max.	9	12	5	12
SCR PRESSURE DROP, "WG - Max.	4.2	4.4	4.6	4.8
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft	1650.0		1650.0	
CO SYSTEM	$843,000		$843,000	
REPLACEMENT CO CATALYST MODULES	$643,000		$643,000	
SCR SYSTEM	$2,835,000		$3,046,000	
REPLACEMENT SCR CATALYST MODULES	$1,479,000		$1,690,000	

ENGELHARD

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CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

GE 7FA – Combined Cycle

GIVEN / CALCULATED DATA	GE 7F	GE 7F	GE 7F	GE 7F
FUEL	NG	OIL	NG	OIL
TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000	3,900,000	4,080,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63	75.23	71.63
O2	12.61	11.04	12.61	11.04
CO2	3.63	5.20	3.63	5.20
H2O	7.60	11.20	7.60	11.20
Ar	0.93	0.93	0.93	0.93
GIVEN: TURBINE CO, ppmvd	9	20	9	20
CALC.: TURBINE CO, lb/hr	31.9	71.7	31.9	71.7
CALC. TURBINE CO, ppmvd @ 15% O2	7.3	15.7	7.3	15.7
GIVEN: TURBINE NOx, ppmvd @ 15% O2	9	42	9	42
CALC.: TURBINE NOx, lb/hr	64.5	355.2	64.5	355.2
CALC. GAS MOL. WT.	28.45	28.45	28.45	28.45
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650	650	650	650
DESIGN REQUIREMENTS				
CO CATALYST CO OUT, ppmvd @ 15% O2	0.7	1.6	0.7	1.6
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	ADVISE	3.5	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12	5	12
GUARANTEED PERFORMANCE DATA				
CO CATALYST CO CONVERSION, % - Min.	90.0%	90.0%	90.0%	90.0%
CO OUT, lb/hr - Max.	3.2	7.2	3.2	7.2
CO OUT, ppmvd @ 15% O2 - Max.	0.7	1.6	0.7	1.6
CO PRESSURE DROP, "WG - Max.	1.2	1.3	1.2	1.3
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%	61.1%	61.1%
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	18.4	3.5	18.4
NOx OUT, lb/hr - Max.	25.1	138.1	25.1	138.1
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	137.1	405.2	99.3	405.2
NH3 SLIP, ppmvd @ 15% O2 - Max.	9	12	5	12
SCR PRESSURE DROP, "WG - Max.	2.0	2.1	2.2	2.4
FIT HRSG INSIDE LINER - 67 ft H x 26 ft W				
CO SYSTEM	$758,000		$758,000	
REPLACEMENT CO CATALYST MODULES	$659,000		$659,000	
SCR SYSTEM	$1,088,000		$1,249,000	
REPLACEMENT SCR CATALYST MODULES	$625,000		$783,000	

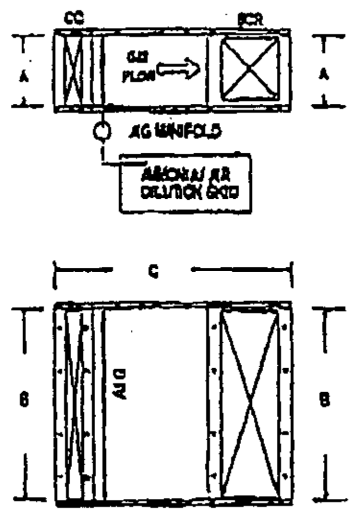
Malcolm Pirnie
CO Oxidation System Components
SCR Catalyst System Components
Engelhard Budgetary Proposal EPB00164
December 19, 2000

Combined Cycle

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	GE 7FA	GE 7FA
	1,055.6	
TURBINE EXHAUST FLOW, lb/hr	3,800,000	3,800,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.18	75.18
O2	12.83	12.83
CO2	3.73	3.73
H2O	7.37	7.37
Ar	0.89	0.89
GIVEN: TURBINE CO, ppmvd @ 15% O2	15	15
CALC.: TURBINE CO, lb/hr	62.0	62.0
GIVEN: TURBINE NOx, ppmvd @ 15% O2	12	12
CALC.: TURBINE NOx, lb/hr	81.5	81.5
ppmv	13.3	13.3
CALC. GAS MOL WT.	28.50	28.50
GAS TEMP. @ CO and SCR CATALYST, F	650	650
DESIGN REQUIREMENTS		
CO CATALYST CO OUT, ppmvd @ 15% O2	3.0	3.0
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	2.5
NH3 SLIP, ppmvd @ 15% O2	10	10
GUARANTEED PERFORMANCE DATA		
CO CATALYST CO CONVERSION, % - Min.	80.0%	80.0%
CO OUT, lb/hr - Max.	12.4	12.4
CO OUT, ppmvd @ 15% O2 - Max.	3.0	3.0
CO PRESSURE DROP, "WG - Max.	0.8	0.8
SCR CATALYST NOx CONVERSION, % - Min.	70.8%	79.2%
NOx OUT, lb/hr - Max.	23.8	17.0
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	2.5
DESIGN INLET ALPHA - NH3:NOx	1.64	1.63
EXP. AQUEOUS NH3 (19% SOL.) FLOW, lb/hr	244.3	267.6
NH3 SLIP, ppmvd @ 15% O2 - Max.	10	10
NH3 SLIP, ppmv	11.1	11.1
SCR PRESSURE DROP, "WG - Max.	1.5	2.2
CO SYSTEM	$587,000	$587,000
REPLACEMENT CO CATALYST MODULES	$808,000	$808,000
SCR SYSTEM	$1,068,000	$1,418,000
REPL. SCR CATALYST MODULES	$624,000	$940,000

Dimensions:
Inside Liner Width (A) 28 ft
Inside Liner Height (B) 67 ft
Reactor Depth (C) 16 ft



2.0 ppmvd SCR system

→ $ 1,583,000
→ $ 1,097,500

per e-mail from Fred Booth of Engelhard on 7/18/01.

ATTACHMENT E

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$758,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$75,800	10% of SCR Associated Equipment
Sales Tax	$45,480	6% of SCR Associated Equipment/Catalyst
Freight	$37,900	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$961,685	
Direct Installation Costs		
Foundation and supports	$76,935	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$134,636	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$38,467	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,234	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$293,506	
Total Capital Costs	$1,255,191	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$62,760	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$25,104	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$12,552	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$37,656	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,109	
Total Direct, Indirect and Capital Costs (TDICC)	$1,644,300	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$219,667	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$24,668	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,545	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$259,056	
Energy Costs		
Heat Rate Penalty	$214,208	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$214,208	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,443	1% of Total Capital Costs
Insurance	$16,443	1% of Total Capital Costs
Annualized Total Direct Capital	$180,544	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$217,736	
Total Annualized Costs	$691,000	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$4,409	per ton of CO Removed
	$4,819	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN Only	DLN with OC
Technical Assessment		
	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs		
Annualized Costs	included	$1,644,300
Cost Effectiveness	included	$691,000
CO Removed (per ton of CO)		
	NA	$4,409
Environmental Impact [b]		
Total CO (TPY)		
CO Reduction (TPY)	183.81	27
Net Pollutant Reduction	NA	-155
Additional Greenhouse Gas (CO_2; tons/yr)	NA	-143
	--	1971
Energy Impacts [c]		
Energy Use (kWh/yr)		
Energy Use (Equivalent Residential Customers/year)	0	3,021,149
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	252
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	31,121
	0	31

[a] See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-11.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year. Lost energy is based on 0.2 percent of 166 MW.

Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

Pollutants	Incremental Emissions (tons/year) of SCR		
	Primary	Secondary	Total
Particulate	9.78	0.11	9.89
Sulfur Dioxide		0.04	0.04
Nitrogen Oxides	0.00	2.07	2.07
Carbon Monoxide	-156.7	1.24	-155.5
Volatile Organic Compounds		0.08	0.08
Total:	-146.9	3.56	-143.4
Carbon Dioxide (additional from gas firing)		1,971.0	1,971.0

Basis:

Lost Energy (mmBtu/year)	31,121

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

ATTACHMENT F

Table B-3A. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$2,835,000	Vendor Estimate
Ammonia Storage Tank	$136,500	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$50,000	Additional NOx Monitor and System
Taxes	$170,100	6% of SCR Associated Equipment and Catalyst
Freight	$141,750	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$3,400,108	
Direct Installation Costs		
Foundation and supports	$272,009	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$476,015	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$136,004	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$68,002	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$34,001	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$34,001	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,040,032	
Total Capital Costs (TCC)	$4,440,140	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$444,014	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$222,007	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$444,014	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$88,803	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$44,401	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$133,204	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,426,444	
Total Direct, Indirect and Capital Costs (TDICC)	$5,866,584	Sum of TCC and TInCC

Table B-4A. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$18,720	24 hours/week at $15/hr
Supervision	$2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$55,220	$300 per ton for Aqueous NH3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	$493,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$19,690	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$676,028	
Energy Costs		
Electrical	$37,968	80kW/h for SCR & 200kW/h for cooling @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$207,224	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$245,192	
Indirect Annual Costs		
Overhead	$46,049	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$58,666	1% of Total Capital Costs
Insurance	$58,666	1% of Total Capital Costs
Annualized Total Direct Capital	$644,151	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$807,531	
Total Annualized Costs	$1,728,751	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$13,636	NOx Reduction Only
	$25,214	Net Emission Reduction

ATTACHMENT G

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
Region 1																				
CT	Bridgeport Energy	520	07/01/1997		06/29/1998	12	Sip Approved	2		SW V84 3A	NG; FO	CC	8,760; 720 FO	6 0 ppm NG; 42 ppm FO	DLN with SCR		10 ppm	GCP	1-hr	Operational
CT	PDC-EL Paso Milford LLC	540	02/17/1998		04/16/1999	14	Sip Approved	2		ABB GT-24	NG; FO	CC	8,760; 720 FO	2.0 ppm NG; 9 ppm FO	SCR	3-hr	2 ppm	CatOx	1-hr	Undergoing testing, Fall 2001
CT	Lake Road Generating	792	?		final		Sip Approved	3		ABB GT-24	NG; FO	CC	8,760, 720 FO	2 0 ppm NG, 9 ppm FO	SCR	3-hr	3 ppm	CatOx	1-hr	
CT	PDC-El Paso, Meriden	544			final	2	Sip Approved	2	?	ABB GT-24	NG, FO?	CC	8,760; 720 FO	2 ppm	SCR	3-hr	52 4 lb/hr	CatOx	1-hr	
CT	PPL Wallingford Energy, LLC	250			final		Sip Approved	5		S & S LM 6000	NG	SC	4,000	2 5 ppm	SCR	1-hr	1.24 Lbs/hr	CatOx	1 Hr	
CT	Towantic Energy Project	540	1201/98		draft 01/12/01		Sip Approved	2		GE Model 7241	NG, FO	CC		2 ppm NG; 5 9 ppm FO	SCR	1-hr	5 ppm	CatOx	1-hr	
MA	Fore River Station, Weymouth	755	?		?		Delegated	2	?	Mitsubishi 501G	NG; FO	CC	8760; 720 FO	2 ppm NG; 6 ppm FO	SCR	1-hr	2 ppm	CatOx	1-hr	
MA	Berkshire Power	272	05/06/1997		09/22/1997	5	Delegated	1		ABB GT24 178 MW, 272 MW total	NG; FO	CC	8,760, 720 FO	3 5 ppm NG/ 9 ppm FO	DLN & SCR & WI &SCR FO		4 ppm	CatOx		Operational
MA	Millennium Power	360	11/21/1997		Final	3	Delegated	1		SW 501G	NG; FO	CC	8,760; 720 FO	3 5 ppm NG/ 9 ppm FO	SCR		4 ppm	CatOx	1-hr	Testing-Problems with engine
MA	Dighton Power Assoc	170	09/29/1997		Final		Delegated	1		ABB GT11N2, 170 MW	NG	CC	8,760	3 5ppm	DLN, SCR	1-hr	4 ppm	CatOx	?	Operational
MA	ANP Bellingham	580	?		Final		Delegated	2		ABB GT-24	NG	CC	8,760	2 0 ppm	SCR	1-hr	3 ppm	CatOx	1-hr	NOx 3 5 ppm/ Steam Augmentation
MA	ANP Blackstone	580	?		Final		Delegated	2		ABB GT-24	NG	CC	8,760	2.0 ppm	SCR	1-hr	3 ppm	CatOx	1-hr	NOx 3 5ppm/ Steam Augmentation
MA	Sithe Mystic Development	1,550	?		final 1/00		Delegated	4		Mitsubishi 501G	NG	CC	8,760	2 0 ppm	SCR	1-hr	2 ppm	CatOx	1-hr	Netted out of PSD/NSR for NOx & SO2, under construction
MA	Cabot Power	350	?		Final		Delegated	1		SW 501G	NG	CC	8,760	2 0 ppm	SCR	1-hr	2 ppm	CatOx	1-hr	
MA	Sithe West Medway	540			final		Delegated	3		GE 7FA	NG	SC	2,500	9 0 ppm	DLN	1-hr	9 ppm	Good Combustion	1-hr	
ME	Androscoggin Energy LLC	150	09/12/1997		03/31/1998	7	Sip Approved	3	3	SW 251B 12A	NG; FO	Cogen	8,760, 720 FO	6 ppm/42 ppm	LNB & SCR gas only	1-hr	5-10ppm	CatOx		Operational
ME	Rumford Power Associates	265	12/23/1997		05/01/1998	4	Sip Approved	1		?	NG, FO	CC	8,760, 720 FO	3 5ppm	SCR	24-hr	15 ppm	GCP	24-hr	almost completed
ME	Casco Bay Energy Co.	520	02/17/1998		07/13/1998	5	Sip Approved	2			NG	CC	8,760	3 5ppm	SCR	24-hr	20 ppm	GCP	24-hr	PSD Review only, alomost completed
ME	Champion International	250	05/14/1998		09/14/1998	4	Sip Approved	1			NG; FO	CC	8,760; 720 FO	9 ppm/ 42 ppm	GCP, DLN for oil	24-hr	9 ppm/ 30 ppm	GCP	24-hr	Netted out of PSD/NSR review, SCR required if 9 ppm not achievable, almost completed
ME	Westbrook Power	528	08/07/1998		12/21/1998	4	Sip Approved	2		GE 7FA	NG; FO	CC	8,760, 720 FO	3 5ppm	SCR	24-hr	15 ppm	GCP	24-hr	almost completed
ME	Gorham Energy	900	04/02/1998		12/04/1998	8	Sip Approved	3		ABB GT-24	NG; FO	CC	8,760, 720 FO	2.5 ppm NG; 9 ppm FO	SCR (LAER)	24-hr	5 ppm	CatOx ?	24-hr	3 5ppm NOx Steam injection, under construction
NH	Newington Energy	525			Final 4/99		Partial Delegation	2		GE 7FA	NG; FO	CC	8,760; 720 FO	2 5 ppm	SCR	3-hr	15 ppm	GCP	1-hr	Under construction
NH	AES Londonderry LLC	720			Final 4/99		Partial Delegation	2		SW 501G	NG, FO	CC	8,760; 720 FO	2 5 ppm NG; 9 ppm FO	SCR	3-hr	15 ppm	GCP	1-hr	under construction
RI	Tiverton Power Associates	265	02/14/1997		02/13/1998	12	Sip Approved	1		GE 7FA	NG	CC	8,760	3 5 ppm	SCR	1-hr	12 ppm	GCP	1-hr	Operational
RI	Reliant Energy, Hope Generating Facility	522			Final		Sip Approved	2		SW 501F	NG	CC	8,760	2 5 ppm	SCR	1-hr	15 ppm	GCP	1-hr	Advised NOx LAER at 2 0ppm (1 hour), under construction
Region 2																				
NY	Athens Generating Co.	1,080	08/15/1998		02/02/2000	17	Delegated	3	3	SW 501 G	NG; FO	CC	8,760	2 0 ppm NG; 9 0 ppm FO	DLN/SCR	1 hour	15 ppm NG; 50 ppm FO	GCP	1 hour	
NY	Bethlehem Energy Center	750	pending				Delegated				NG	CC	8,760			1 hour				Response to stack height inter TOA2 in 8/5/99 Our comments out 9/28/99
NY	NYPA Poletti	500	pending				Delegated				NG, FO	CC	8,760			1 hour				EPA monitoring waiver approval 12/28/99. Protocol comments out 12/10/99
NY	Sithe Energy -Torne Valley	827	pending				Delegated				NG	CC	8,760			1 hour				PSD application in 3/28/00. Article X application

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NY	TwinTier Power (Summit Energy)	520	pending				Delegated				NG	CC	8,760			1 hour				EPA waiver approval middle of May Revised protocol O K., contingencies: 12/13/99
NY	Sunset Energy Fleet	520	pending				Delegated				NG, FO	CC	8,760			1 hour				Protocol O K 3/20/00 Inventory approval in
NY	Amr Nat Power Ramapo Energy	1,100	pending				Delegated				NG	CC	8,760			1 hour				Monitoring waiver approved on 12/28/99 Protocol approved 3/21/00.
NY	Sithe Energy Heritage Station	800	08/09/2000		11/01/2000	3	Delegated	2	0	GE 107H	NG only	CC	8,760	2 0 ppm NG only	DLN/SCR	1 hour	3 ppm	CatOx	1 hour	Application in 2/23/00; in compliance/complete on 4/21/00.
NY	Southern Energy at Bowline	750					Delegated				NG; FO	CC	8,760			1 hour				Application in 3/21/00 EJ issue for PSD completeness
NY	Con Edison - East River	450	pending				Delegated				NG; FO	CC	8,760			1 hour				Revised protocol in 4/11/00. PSD and NSR applicability analysis in 5/3/00
NY	SCS Energy - Astoria	1,000	pending				Delegated				NG, FO	CC	8,760			1 hour				Protocol comments 12/21/99 Revised waiver comments out 5/8/00
NY	Grassy Point - Havestraw Bay	550	pending				Delegated				NG, FO	CC	8 760			1 hour				Protocol comments out 1/4/00 EPA approval of onsite data 4/28/00
NY	Keyspan - Ravenswood	250	pending				Delegated				NG, FO	CC	8,760			1 hour				Protocol comments out 3/16/00 (EPA
NY	Glenville Energy Park	520	pending				Delegated				NG	CC	8,760			1 hour				Revised data for Preliminary Scoping Statement in 5/4/00
NY	Brookhaven Energy Project	580	pending				Delegated				NG	CC	8,760			1 hour				Preliminary Scoping Statement in 3/24/00
NY	Oak Point Energy - Bronx	1,075	pending				Delegated				NG	CC	8 760			1 hour				Responses from the applicant received on 11/27/00
NY	Orion Astoria - Queens	1,842	pending				Delegated				NG; FO	CC	8 760			1 hour				Applicant submitted a modeling protocol and a source inventory request on 12/20/00
NY	Caithness Island - Brookhaven	750	pending				Delegated				NG, FO	CC	8,760			1 hour				
NY	Kings Park - Smithtown	300	pending				Delegated				NG, FO	SC	8,760			1 hour				Not PSD-affected (simple cycle)
NY	Wawayanda - Orange County	710	pending				Delegated				NG, FO	CC	8 760			1 hour				Modeling protocol submitted on 12/22/00
NY	NYPA's Simple Cycle Turbines at 7 different locations in NYC	460	12/01/2000		01/12/2001	2	Delegated	11	0	GE LM 6000	NG	SC	8 760	2.5 ppm NG	SCR	1 hour	5 ppm	CatOx	1 hour	These 11 turbines are not subject to NSR/PSD The one located in Staten Island (#11) has not yet been issued Installation will begin soon and operation will be in the summer of 2001
NJ	Mantua Creek Generating	800	10/15/1999		01/10/2000	3	Delegated	3	0	ABB GT-24	NG; FO	CC	8,760	2 5 ppm NG; 6 ppm FO	DLN/SCR	1 hour	3 ppm	CatOx	1 hour	Final permit issued Expected start of construction, March 2001.
NJ	Cogen Technology - Linden	181	09/15/1999		12/01/1999	2 5	Delegated	1	0	GE 7FA	NG, FO	CC	8,760	2 5 ppm NG, 6 ppm FO	DLN/SCR	1 hour	2 ppm - gas 6 ppm - oil	CatOx	1 hour	Final permit issued
NJ	AES Red Oak Project	816	12/06/1999		01/28/2000	2	Delegated	4	0	SW 501G	NG	CC	8,760	3 ppm	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Final permit issued
NJ	PSEG Fossil LLC - Linden	170	12/15/2000		02/10/2000	2	Delegated	2	0	GE 7EA	NG; FO	SC	8,760	12 ppm NG; 42 ppm FO	DLN	1 hour	n/a	n/a	n/a	Not subject to NSR/PSD. Unit started operation in April, 2000
NJ	PSEG Fossil LLC - Burlington	170	03/15/2000		05/07/2000	4	Delegated	4	0	GE LM 6000	NG	SC	8,760	25 ppm	water injection	1 hour	70 ppm	n/a	n/a	Not subject to NSR/PSD Unit started operation in May, 2000
NJ	Tosco Bayway Refinery Cogen Project	130	pending		on hold		Delegated	1	0	SW 501D5	NG, refin gas	CC	8,760	3 ppm - gas 10 ppm- ref. gas	DLN	1 hour	4 ppm - Gas 10 ppm - ref gas	CatOx	1 hour	Application is on hold. Ownership may change to PP&L Global.
NJ	Liberty Generating Project	1 090	pending		applic under review		Delegated	3	3	SW 501G	NG	CC	8,760	2 5 ppm	DLN/SCR	1 hour	1.5 ppm	CatOx	1 hour	Applicant wants to change SW turbines with GE turbines
NJ	PSEG Fossil LLC - Kearney	750	pending		applic under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application to be revised by PSE&G
NJ	PSEG Fossil LLC - Bergen	500	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG, 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application under review

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NJ	PSEG Fossil LLC - Linden	1,186	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application under review.
NJ	PSEG Fossil LLC - Sewaren	500	pending		applic. under review		Delegated	3	3	GE 7FA	NG; FO	CC	8,760	2.5 ppm NG; 9 ppm FO	DLN/SCR	1 hour	4 ppm	CatOx	1 hour	Application under review
NJ	Sithe Energy (GPU) - Reliant Energy	520	pending		applic. under review		Delegated	3	0	unk	NG	SC	8,760	9 ppm	DLN	1 hour	9 ppm	n/a	1 hour	Application under review.
NJ	Statoil Celtic, Inc.	750	pending		applic. under review		Delegated	3	3	GE 7FA	NG, FO	CC	8,760	3.5 ppm	DLN/SCR	1 hour	3 ppm	CatOx	1 hour	Application on hold. Ownership may change to Calpine Corp
NJ	PSEG Fossil LLC - Kearney	170	pending		applic. under review		Delegated	4	0	GE LM 6000	NG; FO	SC	8,760	25 ppm NG; 42 ppm FO	water injection	1 hour	n/a	n/a	n/a	Not subject to NSR/PSD
NJ	PSEG Fossil LLC - Burlington	340	pending		applic. under review		Delegated	4	0	GE 7EA	NG; FO	SC	8,760	9 ppm NG, 42 ppm FO	DLN	1 hour		CatOx	1 hour	Application under review.
NJ	Sithe Energy (GPU) - Belvidere	85	withdrawn		withdrawn		Delegated	1		(85 MW)	NG	SC	8,760	9 ppm		1 hour	4 ppm	CatOx	1 hour	
NJ	Sithe Energy (GPU) - Forked River	130	withdrawn		withdrawn		Delegated	2		GE Frame 6	NG	SC	8,760			1 hour	4 ppm	CatOx	1 hour	
NJ	Sithe Energy (GPU) - Sayerville	840	withdrawn		withdrawn		Delegated	3		(840 MW total)	NG	CC	8,760			1 hour	4 ppm	CatOx	1 hour	
NJ	Sithe Energy (GPU) - Gilbert	100	withdrawn		withdrawn		Delegated	-		100 MW total	NG	CC	8,760		DLN/SCR	1 hour	4 ppm	CatOx	1 hour	addition of HRSG and steam generator to existing turbine
PR	PREPA-San Juan	464	03/16/2000		03/02/2000	22	EPA-lead	2	0	SW 501	FO	CC	8,760	no PSD affected	n/a	n/a	25 ppm FO	GCP	3 hours	Subject to PSD for CO and VOC only
VI	VIWAPA-St Thomas	24	07/28/2000		01/03/2001	5	EPA-lead	1	0	UT FT8-1 Power Pac	FO	SC	8,760	42 ppm	WI	24 hours	10 ppm FO at 100% load	GCP	3 hours	UT = United Technologies
Region 3																				
DE	Hay Road - Delaware	550	06/19/2000		10/17/2000	6	SIP Approved	3		SC by 2001 then CC by 2003, + 550 MW	NG/FO	SC			LNB - SC and SCR CC					
DE	NRG Energy	100	08/24/2000		10/20/2000	3	SIP Approved	2		LM 6000	NG/FO	SC		73 lb/hr on oil	lnb	1 hour	165 lb/hr on ng	GCP	1 hour	SYNTHETIC MINOR - BASED ON DE DUAL DEFINITION EACH POLLUTANT LESS THAN 24.9 TONS EACH TURBINE
MD	ODEC Rock Springs - Cecil Co. MD	1,020	08/06/1999		10/30/2000	14	SIP Approved	6		GE 7FA	NG	SC		9ppm	Dry LNB		9ppm	GCP		
MD	Kelson Ridge	1,650	Application under review by state Feb 2001				SIP Approved	6		Siemens	NG	CC			SCR Proposed			Cat Ox proposed		Major NSR Review
MD	Perryman Expansion	280	no application yet								NG	Conversion to CC							Expansion at existing plant	Modification to existing permit
MD	Dickerson Expansion	425	no application yet					2		GE 7FA	NG	CC								Modification to existing permit (add 2 turbines, repower 2 turbines)
MD	Duke Energy Point of Rocks	620	no application yet								NG	CC								Major NSR
MD	AES Cumberland	180	no application yet								Coal	?								Major NSR
VA	Virginia Power - Remington, VA	550	02/01/1999		09/01/1999	7	SIP Approved	3		GE 7FA	NG/FO	SC		9ppm/42 ppm fo	LNB/WI	1hour	9 ppm	GCP	3 hour	synthetic minor 249 tons/NOx
VA	Dominion Energy - Caroline County, VA	550			07/02/2000		SIP Approved	5		GE 7FA	NG/FO	SC		9ppm/42 ppm	LNB/WI			GCP		synthetic minor 249/NOx
VA	Doswell - Hanover Co., VA	190			04/01/2000		SIP Approved	2		LM 6000		SC								Expansion Existing Facility
VA	Wolf Hills - Washington Co., VA	280	03/14/2000		05/01/2000	3	SIP Approved	10		Pratt and Whitney/ FT8 (57MW)	NG	SC	Fuel limitation (4700 mmscf/year nat gas	25 ppm and 29.6 lb/hr at base/peak load	WI	1 hour	18 ppm	Cat Ox	1 hour	Synthetic Minor 249 tons/NOx - Each turbine limited to no more than 27 TPY
VA	Tenaska	900	App Under review by state		]		SIP Approved	3		GE 7FA	NG - Distillate	CC with duct burners	8,760	4.5 ppm or 7 ppm distillate PROPOSED LIMITS - APP	SCR		21 ppm proposed in application	GCP		PSD

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
VA	ODEC - Louisa County	570	applic under review				SIP Approved	3				SC								Synthetic Minor 249 tons/NOx
VA	Commonwealth Chesapeake	350	08/05/2000		10/05/2000	3	sip approved	4		LM6000	Fuel Oil	SC		42 ppm	WI	1 hour	30	GCP	1 hour	
VA	Cogentrix - henry County	1,600	Pre application meeting with state only					6				CC								PSD Review
VA	Competitive Power Ventures Fluvanna County	530	Project Cancelled - Zoning Denied					4				CC								_____Cancelled ____
VA	Wythe Energy	620	app in house 4-2001					4	yes	GE 7 FA	NG	CC		3.5 ppm	SCR			State comments - Cat OX		
VA	Cynergy - Henry County	320	pre app meeting with state only					4				SC								syn minor
VA	Mirant - Danville	320	announced 6/21/01									SC								
VA	ODEC - Faquier County	500	Zoning Application not yet approved/disapproved no application to state																	Synthetic Minor - 249 Tons/Nox
PA	Ontelaunee Energy - PA	544	01/20/2000		10/01/2000	10	SIP Approved	2		Siemens 501F	NG	CC		2.5 ppm	SCR		10 ppm	GCP		
PA # 32-50109	AES Ironwood, LLC	700	05/19/1998		03/29/1999	10	SIP Approved	2			NG; FO	CC	8760 744 (oil)	4.5/10	ALNB, SCR & WI (oil) (LAER)	?	5/10	Entristic high thermodynamic eff	?	Load restriction 85%
PA	Liberty Electric - Eddystone PA	500	12/01/1999		05/01/2000	8	SIP Approved	2	2	GE 7FA	NG/FO	CC	(NG 2117 mscf/12 month rolling) 8760 hours	3 5 ppm CT and 5 0 ppm CT + DB	SCR	1 hour	9ppm CT + 20 ppm CT + DB0	GCP	1 hour	12 month rolling limit each turbine NOx 113 4 ton CO 253 7 ton VOC 25.1 ton
PA	Panda Perkiomen - Montgomery Co , PA	1,000			applic under review		SIP Approved			LM 6000		CC								Strong Public Opposition and Water reuse issues
PA	SWEC - Falls Township, PA	500					SIP Approved	2	2	GE 7FA	NG/FO	CC	720 on fuel oil	3 ppm	SCR	1 hour	3 ppm	cat ox	1 hour	EPA comment 4/20/01
PA	FPL - Marcus Hook PA	750			applic under review		SIP Approved			GE 7FB		CC								
PA	Limerick - Limerick, PA	500			applic. under review		SIP Approved					CC								
PA	Armstrong	660	08/17/2000		12/07/2000	12	SIP Approved	4		GE 7FA		SC	8900 unit hours on ng/ 770 unit hours on FO	9 ppm ng/42 ppm fo	LNB		20 ppm			
PA	Connectiv - Lancaster	500	Application received by State (2/01) - no information to EPA as of 2/12/01				SIP Approved													
PA	Connectiv - Delta Project - York County	1,100	Application received by State (2/01)				SIP Approved	6		Siemens V84.2		CC			SCR proposed			GCP proposed		
PA	Connectiv - Indiana County	1,000	Application rec'd by state on 2/12/01				SIP Approved	6		Siemens V84.2		SC and CC			SCR proposed for CC					
PA	Sithe	1,600	app rec by PADEP 4/17/00 - no information to EPA as of 2/12/01				SIP Approved													

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PA	Lower Mount Bethel PPL	600	01/25/2001		Expected March 2001	delayed by public comment	SIP Approved	2	2	Siemens W501F	ng	CC w/DB		3 5 ppm	Dry LNB + SCR		6 PPM	Cat Ox		
PA	Allegheny Harrison	88	05/08/2000		pending	delayed by Storage Tank Issues	SIP Approved	2		LM 6000	NG/FO	SC	4050 hours / 450 diesel							
PA	Reliant Upper Mount Bethel	560						2	2	Siemens		CC			SCR proposed			Cat ox proposed		
PA	Handsome Lake Energy	280			09/29/2000			10		Pratt and Whitney/ FT8 (57MW)	NG	SC	Fuel limitation (1871 mmscf/year nat gas	25 ppm and 30 1 lb/hr at base/peak load	WI	1 hour	25 ppm	Cat Ox	1 hour	Synthetic Minor 95 tons/NOx 12 month rolling CO 60 4 ton/year VOC 7.5 ton/year
PA	Armstrong	660			12/07/2000			4		GE 7FA	NG/FO	SC	14 77 x 10 9 NG 11.41 x 10 6 fuel oil	9 ppm NG/ 64 lb/hr 56 ppm oil 456 lb/hr	LNB NG - WI Oil	1 hour	31 lb/hr NG 79 lb/hr Oil	GCP	1 Hour	Total Plant 253 TPY NOx 124 6 TPY CO 11 6 TPY VOC
WV	Panda	1,000	App with state - no draft to EPA as of 2/12/01				SIP Approved				NG	CC								
WV	Big Sandy	330			Issued						NG	SC								
WV	Pleasants	335			Issued						NG	SC								
WV	Twelvepole Creek	510			Issued						NG	SC								
WV	Anker	1,000	App with state - no draft to EPA as fo 2/12/01				SIP Approved				Coal	CFB								
Region 4																				
AL	Alabama Power - Olin Cogeneration	137	07/31/1997		Dec-97	4	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	15 ppm	DLN		0 07 lb/MMBtu	GCP		Power Augmentation
AL	US Alliance Coosa Pines CoGen	89	02/13/1998		Oct-98	8	SIP Approved													
AL	Alabama Power - GE Plastics Cogeneration	100	10/01/1997		May-98	7	SIP Approved	1	1	GE 7EA (80 MW)	NG	CC	8,760	9 ppm; 0 20 lb/MMBtu (DB)	DLN		0 08 lb/MMBtu (combined)	GCP		
AL	Alabama Power, Plant Barry	800	03/30/1998		Aug-98	4	SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm / 0.013 lb/MMBtu	DLN/SCR		0 057 lb/MMBtu	GCP		
AL	Alabama Power, Plant Barry	200	04/02/1999		Aug-99	4	SIP Approved	1	1	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm / 0 013 lb/MMBtu	DLN/SCR		0 060 lb/MMBtu	GCP		
AL	Mobile Energy, LLC - Hog Bayou	200	06/08/1998		1-99	7	SIP Approved	1	1	GE 7FA (168 MW)	NG; FO	CC	8,760; 675 FO	3 5 ppm NG, 41 ppm w/ FO	DLN/SCR; WI		0 040 lb/MMBtu NG, 0 058 lb/mmBtu FO	GCP		
AL	Alabama Power - Theodore Cogeneration Facility	210	10/05/1998		3-99	5	SIP Approved	1	1	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm/ 0 013 lb/MMBtu	DLN/SCR		0 086 lb/MMBtu	GCP		
AL	Tenaska Alabama Partners	846	06/09/1999		11-99	5	SIP Approved	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3 95 ppm NG; 11 3 ppm FO	DLN/SCR, WI/SCR		32.9 ppm NG, 46 7 ppm NG/FO	GCP		
AL	Georgia Power - Goat Rock	-	11/30/1999		4-00	5	SIP Approved	8	8	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm/ 0 013 lb/MMBtu	DLN/SCR		0.086 lb/MMBtu	GCP		
AL	Georgia Power - Goat Rock (revision of above PSD application)	2,460	10/17/2000		4-01	6	SIP Approved	8	8	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm/ 0 013 lb/MMBtu	DLN/SCR		0 086 lb/MMBtu	GCP		
AL	Alabama Electric Cooperative - Gantt Plant	500	12/02/1999		3-00	3	SIP Approved	2	2	SW 501F (166 MW)	NG	CC	8,760	3 5 ppm / 0 013 lb/MMBtu	DLN/SCR		0 057 lb/MMBtu	GCP		
AL	South Eastern Energy Corp	1,500	01/18/2000		1-01	12	SIP Approved	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		9 or 19 or 22 ppm	GCP		For NOx and CO SC w/GE or SC w/SW501F or CC (either)
AL	Calpine Solutia - Decatur	700	01/24/2000		6-00	6	SIP Approved	3	3	SW501F (180 MW)	NG	CC	8,760	3 5 ppm/ 0 013 lb/MMBtu	SCR		0.117 lb/mmBtu	GCP		
AL	Calpine BP Amoco	700	02/02/2000		6-00	5	SIP Approved	3	3	SW501F (180 MW)	NG	CC	8,760	3.5 ppm/ 0 013 lb/MMBtu	SCR		0 117 lb/mmBtu	GCP		

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
AL	Tenaska Alabama II Generating Station	900	05/01/2000		2-01	9	SIP Approved	3	3	GE 7FA or Mitsubishi M501F	NG, FO	CC	8,760; 720 FO	0 013/0.048 lb/mmbtu NG/FO - GE; 0 013/0 046 lb/mmbtu NG/FO - Mit	SCR/WI		0 037/0 047/0 089 lb/mmbtu (base/PA/FO) - GE; 0 088/0 116/0 .35 lb/mmbtu (base/PA/FO) - Mit	GCP		
AL	Hillabee Energy Center	700	05/01/2000		1-01	8	SIP Approved	2	2	SW501G (229 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		0 023/0 076 lb/mmBtu (w/PA and/or DB)	GCP		PA = Power Augmentation, DB= Duct Burning
AL	Duke Energy - Alexander City	1,260	07/13/2000		2-01	7	SIP Approved	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3 5 ppm (0 013 lb/mmBtu) CC, 9/12 ppm (0.033 lb/mmBtu) SC	SCR - CC, DLN-SC	an/1-hr	0 059 lb/mmBtu (130 lb/hr) CC; 0 09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
AL	GenPower - Kelly, LLC	1,260	08/10/2000		1-01	5	SIP Approved	4	4	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	SCR		9 ppm, 14 ppm (w/DB)	GCP		
AL	Blount County Energy	800	08/31/2000		1-01	5	SIP Approved	3	3	"F" Class (170 MW)	NG	CC	8,760	0 013 lb/mmBtu (30.7 lb/hr)	SCR	3-hr	0 033 lb/mmBtu (77.7 lb/hr)	GCP		
AL	Calhoun Power Company	680	08/30/2000		1-01	5	SIP Approved	4	0	GE 7FA (170 MW)	NG; FO	SC	4,000; 1,000 FO	0.033/0.044/0 055 lbmmbtu NG, 0 163 lb/mmbtu (327 lb/hr) FO	DLN; WI		0 017/0 064/0 .026 lbmmbtu (NG/FO/peak)	GCP		NOx-(annual avg /1-hr avg /peak mode)
AL	Alabama Power - Autaugaville	1,260	09/05/2000		1-01	4	SIP Approved	4	4	"F" Class (170 MW)	NG	CC	8,760	3 5 ppm (0 013 lb/mmBtu)	SCR		0 035 lb/mmBtu	GCP		
AL	Tenaska Alabama III Partners	510	08/28/2000		1-01	5	SIP Approved	3	0	GE 7FA (170 MW)	NG, FO	SC	3,066, 720 FO	15 ppm NG; 42 ppm FO	DLN, WI		15 ppm	GCP		
AL	Tenaska Alabama IV Partners	1,840	03/02/2001	#######	10/09/2001	7	SIP Approved	6	6	Mit 501F (170 MW)	NG, FO	CC	8,760; 720 FO	3 5 ppm NG, 12 ppm FO	SCR		0 088 lb/mmBtu NG (0 115 w/PA & DB); 0 35 lb/mmBtu FO	GCP		SCONOx - $6,145/ton NOX; CatOx- $1,506/ton CO
AL	Duke Energy Autauga, LLC	630	05/11/2001		10/29/2001	5	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		15 ppm	GCP		SCONOx - $18760/ton NOX, CatOx- $5,006/ton CO
AL	Duke Energy Dale, LLC	630	06/27/2001		12/17/2001	6	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm (0 013 lb/mmbtu)	SCR		0 033 lb/mmbtu	GCP		SCONOx - $18,403/ton NOX, CatOx- $2,634/ton CO+VOC
AL	Kinder Morgan Alabama LLC	7						7	7	LM 6000 & GE 7EA		CC	5750; 8760							
FL	City of Lakeland, McIntosh Power Plant	250	12/09/1997		7-10-98	7	SIP Approved*	1	0	SW 501G (230 MW)	NG; FO	SC (later CC)	7,008, 250 FO	25 ppm until 5/2002, 9 ppm after, 7 5 ppm if CC, NG, 42 ppm or 15 ppm FO	DLN or SCR, WI or SCR		25 ppm NG, 90 ppm FO	GCP		Power Augmentation
FL	Santa Rosa Energy Center, Sterling Fibers Mfg. Facility	241	07/08/1998		12-4-98	5	SIP Approved*	1	1	GE 7FA (167 MW)	NG	CC	8,760	9 ppm, 9 8 ppm w/ DB	DLN		9 ppm; 24 ppm w/ DB	GCP		If a different CT is used, SCR may be required to meet 6 ppm NOx)
FL	Kissimmee Utility Authority, Cane Island Power Park -Unit 3	250	07/31/1998		draft permit		SIP Approved (1)	1	0	GE 7FA (167 MW)	NG; FO	CC	8,760; 720 FO	3 5 ppm NG, 15 ppm FO	SCR		12 ppm, 20 ppm w/ DB NG, 30 ppm FO	GCP		
FL	Duke Energy - New Smyrna Beach	500	10/19/1998		draft permit		SIP Approved (1)	2	0	GE 7FA (165 MW)	NG	CC	8,760	9 ppm or 6 ppm	DLN or SCR		12 ppm	GCP		
FL	Polk Power (TECO)	330	02/23/1999		10-99	8	SIP Approved (1)	2	0	GE 7 FA (165 MW)	NG; FO	SC	5,130, 750 FO	10.5 ppm NG; 42 ppm FO	DLN, WI		15 ppm NG; 33 ppm FO	GCP		
FL	Oleander Power	950	03/19/1999		11-99	8	SIP Approved (1)	5	0	GE 7FA (190 MW)	NG, FO	SC	3,390, 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG, 20 ppm FO	GCP		
FL	Lake Worth Generation	244	03/22/1999		11-99	8	SIP Approved (1)	1	1	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		
FL	City of Tallahassee	250	03/17/1997		5-98	14	SIP Approved (1)													
FL	Hardee Power Partners (TECO)	75	06/29/1999		10-99	4	SIP Approved (1)	1	0	GE 7EA (75 MW)	NG; FO	SC	8,760, 876 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		
FL	Reliant Energy Osceola	510	08/08/1999		12-99	4	SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	3,000; 2,000 FO	10 5 ppm NG, 42 ppm FO	DLN; WI		10 5 ppm NG, 20 ppm FO	GCP		
FL	Florida Power Corp., Intercession City	261	06/01/1999		12-99	6	SIP Approved (1)	3	0	GE 7EA (87 MW)	NG, FO	SC	3,390, 1,000 FO	9 ppm NG; 42 ppm FO	DLN, WI		25 ppm NG; 20 ppm FO	GCP		

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
FL	Jacksonville Electric Authority - Brandy Branch	510	05/26/1999		10-99	5	SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	4,000; 800 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		
FL	Gulf Power - Smith Station	340	06/14/1999		7-00	13	SIP Approved (1)	2	2	GE 7FA (170 MW)	NG	CC	8,760	82.9 lb/hr w/DB, 113.2 lb/hr w/ DB & SA	DLN	30-day	16 ppm w/ DB, 23 ppm w/ DB & SA	GCP		Netting out of PSD for NOx and CO; SA = steam augmentation
FL	Florida Power & Light - Sanford	2,200	06/21/1999		9-99	3	SIP Approved (1)	8	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		Repowering, 4 units FO
FL	IPS Avon Park Corp - Vandola Power Project	680	09/03/1999		12-99	3	SIP Approved (1)	4	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN, WI		12 ppm NG; 20 ppm FO	GCP		Netting out of PSD for NOx and CO
FL	Gainesville Regional Utilities, Kelly Generating Station	133	09/08/1999		2-00	5	SIP Approved (1)	1	0	GE 7EA (83 MW)	NG; FO	CC	8,760; 1,000 FO	9 ppm NG, 42 ppm FO	DLN; WI		20 ppm NG; 20 ppm FO	GCP		Netting out of PSD review for NOx
FL	IPS Avon Park - Shady Hills	510	10/28/1999		1-00	3	SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG, 20 ppm FO	GCP		
FL	Palmetto Power	540	10/25/1999		6-00	8	SIP Approved (1)	3	0	SW 501F (180 MW)	NG	SC	3,750	15 ppm	DLN		25 ppm (15 ppm after 1st yr.)	GCP		
FL	Granite Power Partners	540	01/19/2000		8-00	7	SIP Approved (1)	3	0	GE/SW (180 MW)	NG; FO	SC	3,000; 500 FO	10.5/15/15 ppm NG; 42 ppm FO (GE only)	DLN		12/16/10 ppm NG; 20 ppm FO (GE only)	GCP		3 vendor options GE 7FA (500 hr/yr FO)/SW 501F/SW 501D5A
FL	IPS Avon Park Corp - DeSoto Power Project	510	02/11/2000		6-00	4	SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		12 ppm NG; 20 ppm FO	GCP		
FL	Florida Power & Light - Martin Power Plant	340	02/23/2000		7-00	5	SIP Approved (1)	2	0	GE 7FA (170 MW)	NG; FO	SC	3,390, 500 FO	9/12/15 ppm NG; 42 ppm FO	DLN; WI		9/15/20 ppm NG; 20 ppm FO	GCP		normal/power aug /peaking
FL	Calpine Osprey Energy Center	527	04/03/2000		07/05/2001	15	SIP Approved (1)	2	2	SW 501FD (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr Block	10 ppm (17 ppm w/DB or PA)	GCP	24-hr Block	2,800 hr/yr - Power Aug mode
FL	Peace River Station	510	06/14/2000		12-00	6	SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 720 FO	9/10 ppm NG, 42 ppm FO	DLN; WI	3-hr test/rolling	8.2 ppm NG; 14.2 ppm FO	GCP	3-hr test	
FL	Hines Energy (FPC)	530	08/02/2000		06/07/2001	10	SIP Approved (1)	2	0	SW 501FD (170 MW)	NG; FO	CC	8,760, 1,000 FO	3.5 ppm NG, 12 ppm FO	SCR; WI	24-hr Block	16 ppm NG; 30 ppm FO	GCP	24-hr Block	SCONOx - $16,712/ton NOx ; CatOx - $2,130/ton CO
FL	Florida Power & Light - Fort Myers	340	08/14/2000		12-00	4	SIP Approved (1)	2	0	GE 7FA (170 MW)	NG; FO	SC	8,760, 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG; 20 ppm FO	GCP		netting out of NOx, CO, PM10 and SO2 review (subject to VOC reveiw)
FL	CPV - Gulfcoast	250	08/11/2000		2-01	6	SIP Approved (1)	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760, 720 FO	3.5 ppm NG; 10 ppm FO	SCR		9 ppm NG; 20 ppm FO	GCP		SCONOx - no cost eval , CatOx - $4,350/ton CO
FL	TECO Gannon/Bayside	1,728	09/27/2000		3-01	6	SIP Approved (1)	7	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 876 FO	3.5 ppm NG; 16.4 ppm FO	SCR		7.2 ppm NG; 14.2 ppm FO	GCP		Repowering project netting out of NOx, CO, PM10 and SO2 review (subject to VOC reveiw)
FL	Duke Energy - Ft Pierce	640	10/11/2000		06/18/2001	8	SIP Approved (1)	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500, 1,000 FO	10.5 ppm NG, 42 ppm FO	DLN; WI	3-hr rolling	25 ppm NG, 20 ppm FO	GCP	3-hr test	SCR - $50,602/ton NOx; CatOx - $21,832/ton CO&VOC
FL	Pompano Beach Energy Center, LLC	510	10/24/2000		draft permit		SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG; 20 ppm FO	GCP		Hot SCR - $20,400/ton NOX; CatOx- $31,800/ton CO
FL	Midway Development Center	510	11/17/2000		2-01	3	SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG (9 ppm on startup); 42 ppm FO	DLN; WI		9 ppm NG; 20 ppm FO	GCP		Hot SCR - $20,700/ton NOX; CatOx- $31,800/ton CO
FL	South Pond Energy Park	600	11/21/2000		draft permit		SIP Approved (1)	3	0	GE 7FA (170 MW)	NG, FO	SC/CC	3,390/8,760; 720 FO	9 ppm /2.5 ppm NG; 36/10 ppm FO	DLN/SCR; WI	3-hr	9 ppm NG; 20 ppm FO	GCP	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode
FL	North Pond Energy Park	430	11/21/2000		applic. under review		SIP Approved (1)	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initially)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode.
FL	Duke Energy Lake	640	12/05/2000		07/18/2001	7	SIP Approved (1)	8	0	GE 7EA (80 MW)	NG	SC	2,500	12 ppm (9 ppm initial test)	DLN, WI	3-hr rolling	20 ppm (25 ppm first year)	GCP	3-hr test	SCR - $15,000/ton NOx; CatOx - $5,563/ton CO
FL	Calpine Blue Heron Energy Center	1,080	12/01/2000		draft permit		SIP Approved (1)	4	4	SW 501F (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		10/15.6/38.5/50 ppm	GCP		base/duct burner/power aug /60-70% load; SCONOx - $9,982/ton NOx; CatOx - $1,553/ton CO
FL	Jacksonville Electric Authority - Brandy Branch (revision)	200	12/22/2000		draft permit		SIP Approved (1)	0	2	GE 7FA (170 MW)	NG; FO	CC	8760, 288 FO	3.5 ppm NG; 15 ppm FO	SCR		12.21/14.17 ppm	GCP		Conversion of 2 SC units to 2 CC units
FL	CPV - Atlantic Power	250	01/11/2001		5-01	4	SIP Approved (1)	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3.5 ppm NG; 10 ppm FO	SCR		9 ppm NG (15 ppm w/PA) ; 20 ppm FO	GCP		PA = Power Augmentation

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
FL	Orlando Utilities - Curtis H Stanton Energy Center	633	01/24/2001		09/26/2001	9	SIP Approved (1)	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760; 1000 FO	3 5 ppm NG, 10 ppm FO	SCR		18 1 ppm NG (26 3 w/PA), 14 3 ppm FO	GCP		
FL	Deerfield Beach Energy Center	510	01/26/2001		draft permit		SIP Approved (1)	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500, 1000 FO	9 ppm NG; 42 ppm FO	DLN; WI	24-hr	9 ppm NG; 20 ppm FO	GCP		
FL	Broward Energy Center	775	04/03/2001		draft permit		SIP Approved (1)	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2 5 ppm/9 ppm	SCR/DLN	24-hr	8 ppm (SC & CC); 12 ppm (CC w/PA)	GCP	3-hr	1 CC w/unfired HRSG & 3 SC, PA = Power Augmentation
FL	Belle Glade Energy Center	600	04/03/2001		01/28/2002	10	SIP Approved (1)	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2 5 ppm/9 ppm	SCR/DLN	24-hr	2.5 ppm (CC)/8 ppm (SC); 14 ppm (CC w/PA)	GCP	3-hr	1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
FL	Manatee Energy Center	600	04/03/2001		01/17/2002	9	SIP Approved (1)	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2 5 ppm/9 ppm	SCR/DLN	24-hr	2 5 ppm/8 ppm, 4 ppm (CC w/PA)	GCP	3-hr	1 CC w/unfired HRSG & 2 SC, PA = Power Augmentation
FL	CPV Pierce Power Generation Facility	250	04/20/2001		08/17/2001	4	SIP Approved (1)	1	0	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	2 5 ppm NG, 10 ppm FO	SCR	24-hr	8 ppm NG (13 ppm w/PA) ; 17 ppm FO (19 ppm 76-89% load, 26 ppm 50-75% load)	GCP	24-hr	PA limited to 2,000 hr/yr
FL	Fort Pierce Repowering Project	180	04/25/2001		08/15/2001	4	SIP Approved (1)	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760, 1,000 FO/2,000, 500 FO	3 5 ppm NG; 12 ppm FO/25 ppm NG, 42 ppm FO	SCR/DLN, WI		3 5 ppm NG; 10 ppm FO/ 16 ppm NG; 50 ppm FO	GCP		CT will operate in both CC and SC modes
FL	TECO Bayside Power Station (repowering)	1,032	06/25/2001		01/09/2002	7	SIP Approved (1)	4	0	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	SCR	24-hr	9 ppm (7.8 ppm test avg.)	GCP	24-hr	Repowering Project: Netting out of PSD for NOx, SO2, lead and SAM (subject for PM10, VOC and CO)
FL	CPV Cana Power Generation Facility	245	09/07/2001		01/17/2002	4	SIP Approved (1)	1	1	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	2 5 ppm NG, 10 ppm FO	SCR	24-hr	8 ppm NG (13 ppm w/PA) ; 17/19/26 ppm FO	GCP	24-hr	PA limited to 2 000 hr/yr, CO w/FO 90-100%/76-89%/50-75% load
FL	FPL Martin	1,150	02/05/2002		applic under review		SIP Approved (1)	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 1,000 FO/1,000; 500 FO	2 5 ppm NG; 12 ppm FO/9-15 ppm NG, 42 ppm FO	SCR/DLN; WI		9-15 ppm NG (29 5 ppm w/DB); 20 ppm FO	GCP		
FL	FPL Manatee	1,150	03/04/2002		applic under review		SIP Approved (1)	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760, 1,000 FO/1,000, 500 FO	2.5 ppm CC/9 ppm SC (15 in HPM)	SCR/DLN	3-hr	29 5 ppm CC/9 ppm SC (15 in HPM)	GCP	3-hr	HPM = High Power Mode
GA	Tenaska Georgia Partners, L P	960	05/01/1998		12-98	7	SIP Approved	6	0	GE 7FA (160 MW)	NG, FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN, WI		15 ppm NG; 20 ppm FO	GCP		
GA	West Georgia Generating; Thomaston	680	03/15/1999		6-99	3	SIP Approved	4	0	GE 7FA (170 MW)	NG, FO	SC	4,760, 1,687 FO	12 ppm NG (15 ppm 30-day avg for peak firing) ; 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		
GA	Heard County Power	510	04/06/1999		10-99	6	SIP Approved	3	0	SW 501FD (170 MW)	NG	SC	4,000	15 ppm	DLN		25 ppm	GCP		
GA	Georgia Power, Jackson County	1,216	02/11/1999		8-99	6	SIP Approved	16	0	GE 7EA (76 MW)	NG, FO	SC	4,000, 1,000 FO	12 ppm NG (15 ppm 30-day avg for peak firing) , 42 ppm FO	DLN WI		0 101 lb/MMBtu NG; 0 046 lb/MMBtu FO	GCP		
GA	Georgia Power - Wansley (Oglethorpe Power)	2,280	12/02/1999		07/28/2000	7	SIP Approved	8	8	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm / 0 013 lb/MMBtu	DLN/SCR	30 day	29 5 ppm/0 066 lb/MMBtu	GCP		
GA	Duke Energy Murray, LLC	1,240	05/25/2000		2-01	9	SIP Approved	4	4	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	DLN/SCR		21.8 ppm	GCP		
GA	Duke Energy Buffalo Creek, LLC	620	10/25/2000		applic. under review		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR		21 9 ppm	GCP		SCONOx - $19 948/ton NOx; CatOx - $2 469/ton CO
GA	Duke Energy Sandersville, LLC	640	10/25/2000		11/09/2001	13	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500, 500 FO	10 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG, 20 ppm FO	GCP		Hot SCR - $36 520/ton NOx; CatOx - $8,330/ton CO
GA	Augusta Energy LLC	750	10/26/2000		09/28/2001	11	SIP Approved	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760, 1,000 FO	3 5 ppm NG; 42 ppm FO	SCR, WI		2 ppm NG; 2 ppm FO	CatOx		SCONOx - $17,490/ton NOx; CatOx - $1 828/ton CO
GA	Oglethorpe Power Corp	648	11/07/2000		08/09/2001	9	SIP Approved	6	0	SW V84 2 (108 MW)	NG, FO	SC	8,760, 500 FO	12 ppm NG, 42 ppm FO	DLN, WI		15 ppm	GCP		Hot SCR - $9,381/ton NOx; CatOx - $3,980/ton CO
GA	Oglethorpe Power Corp Wansley	521	12/09/2000		01/15/2002	13	SIP Approved	2	2	SW V84 3a2 (167 MW)	NG	CC	8,760	3 0 ppm	SCR		2 0 ppm	GCP		

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GA	GenPower McIntosh	528	12/27/2000		applic under review		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	SCR		9 ppm/14 (w/DB) ppm	GCP		
GA	Effingham Power Co	525	12/27/2000		draft permit		SIP Approved	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3 5 ppm	DLN/SCR		9 ppm	GCP		Initially SC, but later converting to CC
GA	Peace Valley Generation Co LLC	1,550	02/20/2001		applic under review		SIP Approved	6	4	"F" Class	NG	CC/SC	8,760/2,500	3 5/9 ppm	SCR/DLN:		10 6 ppm (25 ppm w/DB)	GCP		
GA	Duke Energy Tift	620	06/13/2001		Appl. withdrawn on 3-6-02		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	SCR		24.1 ppm	GCP		SCONOx - $16 274/ton NOx; CatOx - $2,095/ton CO
GA	CPV Terrapin, LLC	800	06/27/2001		applic under review		SIP Approved	3	3	GE 7FA (170 MW)	NG; FO	CC	8,760; 720 FO	3 5 ppm NG, 5 4 ppm (NG w/DB); 8 0 ppm FO	SCR		9 ppm NG; 13 6 ppm (NG w/DB); 24 ppm FO	GCP	24-hr rolling	
GA	Kinder Morgan Georgia, LLC - Tift Power	560	07/30/2001		applic under review		SIP Approved	7	7	1 - GE 7EA & 6 - LM6000	NG	CC	8 760, 3,760 (part load)	9 ppm & 22 ppm	DLN & WI	annual	158 5 lb/hr & 141.0 lb/hr	GCP		
GA	Hartwell Development Co	564	07/31/2001		applic under review		SIP Approved	2	0	GE 7FA (176 MW)	NG	CC	8,760	3 5 ppm	SCR		7.4 ppm	GCP		SCONOx - $35 422/ton NOx; CatOx - $4 964/ton CO
GA	MEA of Georgia - W. R Clayton	500	08/07/2001		applic under review		SIP Approved	3	0	GE 7FA (170 MW)	NG, FO	SC	8,760; 1,500 FO	12 ppm NG; 42 ppm FO	DLN, WI	24-hr	13 1 ppm NG; 32 40 ppm FO	GCP	24-hr	Hot SCR - $14,100/ton NOx; CatOx - $15,000/ton CO
GA	Duke Energy Baker, LLC	640	08/17/2001		applic under review		SIP Approved	8	0	GE 7EA (80 MW)	NG, FO	SC	2500, 500 FO	12 ppm NG (9 ppm annual); 42 ppm FO	DLN: WI		24.7 ppm NG: 18 4 ppm FO	GCP		Hot SCR - $36,497/ton NOx; CatOx - $9 210/ton CO
GA	Athens Energy Center	564	09/05/2001		applic under review		SIP Approved	2	0	GE 7FA (176 MW)	NG	CC	8,760	3 5 ppm	SCR		7.9 ppm	GCP		SCONOx - $35,321/ton NOx; CatOx - $4 964/ton CO
GA	Savannah Electric and Power - Plant McIntosh	1,260	11/20/2001		applic under review		SIP Approved	4	4	GE 7FA (170 MW)	NG; FO	CC	8,760; 1,000 FO	3 5 ppm	SCR		0 063 lb/mmbtu NG; 0 069 lb/mmbtu FO	GCP		SCONOx - technically infeasible, CatOx - $2,172/ton CO
GA	Live Oak Co., LLC	600	02/22/2002		applic. under review		SIP Approved	2	2	SW 501FD (170 MW)	NG	CC	8,760	3 5 ppm	SCR		10 ppm (17 ppm w/DB or PA)	GCP		
GA	Baldwin County Energy Center	560	03/01/2002		applic. under review		SIP Approved	2	2	GE 7FA (176 MW)	NG	CC	8,760	3 5 ppm	SCR		9 ppm (24 ppm w/DB)	GCP		
KY	Kentucky Pioneer Energy	540	01/31/2000		06/08/2001	16	SIP Approved	2	0	GE 7FA (197 MW)	syngas/NG	CC	8,760	15/20 ppm	Steam Injection	3-hr	15/20 ppm	GCP	3-hr	
KY	Duke Energy - Marshall Co	640	02/08/2000		draft permit		SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr/an	20 ppm NG; 25 ppm FO	GCP		
KY	Duke Energy Metcalfe	640	09/01/2000		draft permit		SIP Approved	8	0	GE 7EA (80 MW)	NG	SC	2 500	12/9 ppm	DLN	1-hr/an	25 ppm	GCP	1-hr	
KY	East Kentucky Power Cooperative Inc	240	03/01/2000		07/27/2001	17	SIP Approved	3	0	GE 7EA (80 MW)	NG, FO	SC	8760; 8,760 FO	9 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		CatOx - $8 000/ton CO
KY	Louisville Gas & Electric - Trimble	960	05/01/2001		06/26/2001	2	SIP Approved	6	0	GE 7FA (160 MW)	NG	SC	8,760	12/9 ppm	DLN	1-hr/an	9 ppm	GCP	3-hr	
KY	Westlake Energy Corp	520	06/13/2001		draft permit		SIP Approved	2	2	"F" Class (180 MW)	NG	SC	8,760	4 5 ppm	SCR		17.2 ppm	GCP		
KY	Duke Energy Trimble	1,240	01/31/2002		applic under review		SIP Approved	4	4	GE 7FA (160 MW)	NG; FO	CC	8,760, 1,000 FO	3 5 ppm	SCR		9/13.9/20 ppm	GCP		
KY	Summer Shade Development Co	680	01/14/2002		applic under review		SIP Approved	4	0	GE 7FA (170 MW)	NG	SC	4,000	9 ppm	DLN		9 ppm	GCP		
MS	LS Power, LP (Batesville)	1,100	05/05/1997		11-97	6	SIP Approved	3	3	SW 501G (281 MW)	NG; FO	CC	8,760 (10% FO)	9 ppm NG, 42 ppm FO	DLN; WI		30 3 ppm NG; 36 ppm FO	GCP		
MS	Mississippi Power Corp Plant Daniel	1,000	06/26/1998		12-98	6	SIP Approved	4	4	GE 7FA (170 MW)	NG	CC	8 760	3 5 ppm / 0 018 lb/MMBtu	DLN/SCR		0 057 lb/MMBtu	GCP		
MS	Duke Energy Hinds, L.L.C.	520	06/30/1999		4-00	7	SIP Approved	2	0	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	DLN/SCR		20 ppm	GCP		
MS	Duke Energy Attala, L.L.C.	520	11/02/1999		4-00	5 5	SIP Approved	2	0	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	DLN/SCR		20 ppm	GCP		
MS	Cogentrix Energy, Southaven Power Project	800	08/09/1999		draft permit		SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	4.5 ppm (10 8 ppm w/ DB)	DLN/SCR		9 ppm, 18 ppm w/ DB	GCP		
MS	Cogentrix Energy, Caledonia Power Project	800	09/22/1999		3-01	18	SIP Approved	3	3	GE 7FA (182 MW)	NG	CC	8,760	3 5 ppm (w/DB)	DLN/SCR		9 ppm	GCP		revised application to add SCR
MS	Duke Energy Southaven	640	12/17/1999		8-00	8	SIP Approved	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500, 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN, WI		20 ppm NG; 25 ppm FO	GCP		

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
MS	GenPower - McAdams LLC	528	02/21/2000		draft permit		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN/SCR	24-hr	7-8 ppm/13 ppm (w/DB)	GCP	24-hr	
MS	Warren Power LLC (revision)	320	03/23/2001		draft permit		SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	2,000	12 ppm (9 ppm annual)	DLN	24-hr	25 ppm	GCP	24-hr	revised to include startup/shutdown emissions in PTE and modeling analysis
MS	Lone Oak Energy Center	800	04/28/2000		draft permit		SIP Approved	3	3	F" Class (180 MW)	NG	CC	8,760	3.5 ppm	SCR		10/25/30/17 ppm	GCP		Base/PA/PA+DF/DF
MS	Lee Power Partners	1,000	05/15/2000		draft permit		SIP Approved	4	4	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		25 ppm	GCP		
MS	Duke Energy Enterprise	160	05/30/2000		draft permit		SIP Approved	2	0	GE 7EA (80 MW)	NG; FO	SC	3,000, 500 FO	12 ppm NG; 42 ppm FO	DLN; WI		20 ppm NG; 25 ppm FO	GCP		
MS	LSP-Pike Energy LLC	1,100	08/08/2000		draft permit		SIP Approved	4	4	F" Class (170 MW)	NG	CC	8,760	4.5 ppm	SCR		33.1 ppm (0.15 lb/mmBTU)	GCP		
MS	Magnolia Energy	900	09/29/2000		draft permit		SIP Approved	3	3	F" Class (170 MW)	NG	CC	8,760	3.5 ppm	SCR		25 ppm	GCP		
MS	MEP Clarksdale Power	320	10/16/2000		draft permit		SIP Approved	4	0	GE 7EA (80 MW)	NG	SC	8,760	9 ppm	DLN		25 ppm	GCP		Hot SCR - $26,567/ton NOx; CatOx - $5,593/ton CO
MS	TVA - Kemper CT Plant	440	01/25/2001		draft permit		SIP Approved	4	0	GE 7EA (110 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; Hot SCR - $13,668/ton NOx; CatOx - $8,036/ton CO
MS	Reliant Energy - Choctaw Co. LLC	844	02/26/2001		draft permit		SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	DLN, SCR	30-day	18.36 ppm	GCP		SCONOx - $48,663/ton NOx; CatOx - $3,550/ton CO
MS	Crossroads Energy Center	580	03/26/2001		applic. under review		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		10.4 ppm	GCP		SCONOx - $23,400/ton NOx; CatOx - $11,039/ton CO
MS	Choctaw Gas Generation LLC	700	04/18/2001		draft permit		SIP Approved	2	2	SW 501G (250 MW)	NG	CC	8,760	3.5 ppm	SCR		23 ppm	GCP		
MS	Duke Energy Homochitto, LLC	630	06/22/2001		applic. under review		SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	20.4 ppm	GCP	24-hr	
MS	LSP Energy (Granite Power)	300	07/09/2001		11/13/2001	4	SIP Approved	1	1	SW 501F (230 MW)	NG	CC	8,760	3.5 ppm	SCR	3-hr	25 ppm	GCP	3-hr	
MS	South Mississippi Electric Power Association	250	11/16/2001		applic. under review		SIP Approved	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	9 ppm	DLN	24-hr	25 ppm	GCP		
MS	New Albany Energy Development	566	01/23/2002		applic. under review		SIP Approved	2	2	GE 7FA (168 MW)	NG	CC	8,760	3.5 ppm	SCR	annual	13.1 ppm	GCP	annual	SCONOx - $26,000/ton NOx; CatOx - $5,100/ton CO
MS	Panada Black Prairie LP	1,040	02/07/2002		applic. under review		SIP Approved	4	4	F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	7.6 ppm or 80 ppm	GCP		GE7FA or SW501F
NC	CP&L Lee Plant - Wayne County	680	10/03/1997		7-98	10	SIP Approved	4		GE 7241 (2) GE 7231 (2) 170 MW (180 mm btu/hr) each	NG	SC	2000 each ?	12 to 42 ppm depending on control, cell cell comments	DLN, WI	?	not given	not given		This was a permit that was reissued since source failed to meet 18 month begin construction deadline
NC	Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	2,040	05/14/2001		applic. under review		SIP Approved	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000, 1,000 FO	3.5/9 ppm NG; 13/42 ppm FO	SCR/DLN; SCR/WI	24-hr	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility 6 CC and 3 SC CTs
NC	Carolina Power & Light, Rowan Co.	850	03/26/1999		11-99	8	SIP Approved	5	0	GE 7FA (170 MW)	NG; FO	SC	2,000, 1,000 FO	9 ppm NG at startup/10.5 ppm long-term, 42 ppm FO	DLN; WI		15 ppm NG; 20 ppm FO	GCP		
NC	Carolina Power & Light, Rowan Co. (revision)	1,110	05/26/2000		draft permit		SIP Approved	2	0	GE 7FA (170 MW)	NG, FO	CC	8,760; 1,000 FO	9 ppm NG, 42 ppm FO	DLN; WI		15 ppm NG, 20 ppm FO	GCP		Modification of previous permit to switch 2 SC -> CC
NC	Rockingham Power (Dynegy)	780	03/31/1999		6-99	3	SIP Approved	5	0	SW 501F (156 MW)	NG; FO	SC	3,000; 1,000 FO	25 ppm NG until 4/01, 20 ppm until 4/02, 15 ppm after; 42 ppm FO	DLN; WI		25 ppm NG; 50 ppm FO	GCP		
NC	Fayetteville Generation	500	04/03/2000		01/10/2002	20	SIP Approved	2	0	GE 7FA (170 MW)	NG, FO	CC/SC	8,760; 1000 FO	2.5/9 ppm NG; 13/42 ppm FO	SCR/DLN, SCR/WI		9 ppm NG; 20-41 ppm FO	GCP		CO level for FO depends on Load
NC	Duke Energy - Buck Steam Station	640	11/16/2000		11/20/2001	12	SIP Approved	8	0	GE 7EA (80 MW)	NG FO	SC	3,000; 1000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN, WI	24-hr	20 ppm NG, 25 ppm FO	GCP	3-hr	CatOx - $11,976/ton CO
NC	Entergy Power - Rowan Generating Facility	930	01/29/2001		draft permit		SIP Approved	6	0	GE 7FA (155 MW)	NG; FO	SC	4,400; 1,000 FO	10.5 ppm NG; 42 ppm FO	DLN, WI		9 ppm NG, 36 ppm FO	GCP		Hot SCR - $13,049/ton NOx; CatOx - $8,204/ton CO

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NC	GenPower Earleys, LLC	528	03/28/2001		01/14/2002	10	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	2 5/3 5 ppm	SCR		9 ppm (14 ppm w/DB)	GCP		CO Limit depends on CT model; NOx limit depends on operating history and 3 3 ppm trigger level SCONOx - $21,942/ton NOx; CatOx - $3,246ton CO
NC	Mirant Gastonia	1,200	10/31/2001		draft permit		SIP Approved	4	4	"F" Class (175 MW)	NG	CC	8,760	2 5/3 5 ppm	SCR	24-hr block	15 or 30 ppm	GCP	24-hr block	CO Limit depends on CT model; NOx limit depends on operating history and 3 3 ppm trigger level
NC	Carolina Plant	1,300	11/15/2001		applic under review		SIP Approved	4	4	GE or SW (170 MW)	NG; FO	CC	8,760	2 5/3 5 ppm; 13/18 ppm	SCR	24-hr block	47 or 50 ppm	GCP	24-hr block	CO Limit depends on CT model, NOx limit depends on operating history and 3 3 ppm trigger level
NC	Mountain Creek - Granville Energy Center	911	01/09/2002		applic. under review		SIP Approved	3	3	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	SCR		9 ppm (24.3 ppm w/DB)	GCP		SCONOx - $22,600/ton NOx; CatOx - $3,560ton CO
SC	Santee Cooper, Rainey Generating Station	870	06/14/1999		4-00	10	SIP Approved	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG, 20 ppm FO	GCP		
SC	Broad River Energy (SkyGen)	513	06/25/1999		12-99	6	SIP Approved	3	0	GE 7FA (171 MW)	NG, FO	SC	3,000, 500 FO	9 ppm NG; 42 ppm FO	DLN, WI		15 ppm NG, 20 ppm FO	GCP		
SC	SC Electric & Gas - Urquhart	444	05/12/2000		9-00	4	SIP Approved	2	0	GE 7FA (150 MW)	NG, FO	CC	8,760, 4,380 FO	45 ppm	DLN		12 ppm NG; 20 ppm FO	GCP		Netted out of NOx, SO2 and PM10 PSD Review
SC	Broad River Energy (SkyGen)	342	07/13/2000		12-00	5	SIP Approved	2	0	GE 7FA (171 MW)	NG	SC	3,000	9 ppm (12 ppm w/SI)	DLN		9 ppm (15 ppm w/SI)	GCP		Steam Injection (SI)
SC	Columbia Energy	515	10/30/2000		4-01	6	SIP Approved	2	2	GE 7FA (170 MW)	NG, FO	CC	8,760, 1,000 FO	3 5 ppm NG; 12 ppm FO	DLN/SCR, WI		17.4 ppm NG, 37 pm FO	GCP		SCONOx - no analysis; CatOx - $1,611/ton CO
SC	GenPower Anderson	640	01/05/2001		07/03/2001	6	SIP Approved	2	2	GE 7FA (170 MW)	NG	CC	8,760	3 5 ppm	DLN/SCR		11 7 ppm	GCP		
SC	Duke Power - Mill Creek (f/k/a/ RIPP)	654	02/28/2001		11/08/2001	9	SIP Approved	8	0	GE 7EA (80 MW)	NG, FO	SC	2,400, 1,000 FO	10.5 (9 initially) ppm NG; 42 ppm FO	DLN; WI	24-hr	25 ppm NG; 20 ppm FO	GCP	24-hr	
SC	Greenville Generating	930	05/04/2001		draft prmit		SIP Approved	6	0	GE 7FA (155 MW)	NG, FO	SC	3,400; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		9 ppm NG; 36 ppm FO	GCP		Hot SCR - $13,909/ton NOx; CatOx - $8,204/ton CO
SC	Greenville Power Project	810	10/03/2001		applic. under review		SIP Approved	3	3	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	3 5 ppm NG; 20 ppm FO	SCR: WI		12.3 ppm NG; 16 5 ppm FO	GCP		SCONOx - $16,300/ton NOx; CatOx - $5,800/ton CO; DB < 5,120 hr/yr
SC	Jasper County Generating Facility	1,260	10/03/2001		applic under review		SIP Approved	4	4	GE 7FA (170 MW)	NG, FO	CC	8,760; 720 FO	3 5 ppm NG; 12 ppm FO	SCR WI	24-hr	9 ppm NG (14 4 w/DB); 20 ppm FO	GCP		SCONOx - $19,870/ton NOx; CatOx - $3,320/ton CO
SC	Cherokee Falls Combined-Cycle Facility	1,260	10/12/2001		applic under review		SIP Approved	4	4	GE 7FA (173 MW)	NG, FO	CC	8,760; 720 FO	3 5 ppm NG, 12 ppm FO	SCR; WI		0.063 lb/mmbtu NG; 0 069 lb/mmbtu FO	GCP		SCONOx - $22,434/ton NOx, CatOx - $2,500/ton CO
SC	Fork Shoals Energy, LLC	1,150	03/01/2002		applic. under review		SIP Approved	2	2	"F" Class (175 MW)	NG	CC	8,760	3.5 ppm	SCR	24-hr	14 ppm (GE7FA/16 ppm (SW501F)	GCP	24-hr	
SC	Cherokee Falls Development Co.	340	03/01/2002		applic under review		SIP Approved	2	0	GE 7FA (170 MW)	NG	SC	4,300	9 ppm	DLN		9 ppm	GCP		Hot SCR - $22,800/ton NOx; CatOx - $10,500/ton CO
SC	GenPower Anderson - revision	340	03/01/2002		applic under review		SIP Approved	2	0	GE 7FA (170 MW)	NG	SC	2,928	9 ppm	DLN		9 ppm*	GCP		Temporary 4 month operating period - *Not Subject to PSD Review for CO, VOC or SO2
SC	Palmetto Energy Center	970	03/01/2002		applic. under review		SIP Approved	3	3	GE 7FB (180 MW)	NG	CC	8,760	3.5 ppm	SCR		15 ppm (31 ppm w/DB)	GCP		SCONOx - $18,789/ton NOx; CatOx - $2,111/ton CO
TN	TVA, Johnsonville Fossil Plant	340	12/08/1998		7-99	7	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN, WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Gallatin Fossil Plant	340	12/02/1998		7-99	7	SIP Approved	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TN	TVA, Lagoon Creek Plant	1,760	11/30/1999		4-00	5	SIP Approved	16	0	GE 7EA (110 MW)	NG, FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI	30/15day	25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
TN	Vanderbilt University	10	12/13/1999		5-00	5	SIP Approved	2	2	GE PGT5B (5.2 MW)	NG	CC	8,760	25 ppm	DLN		25 ppm	GCP		
TN	Memphis Generation LLC	1,050	06/13/2000		draft permit		SIP Approved	4	0	GE 7FA (170 MW)	NG	CC	8,760	3.5 ppm	SCR		0.03 lb/mmBtu	GCP		Phase I - 1 CT (up to 7% total plant heat input from refinery fuel gas), Phase II - 3 CTs (up to 2% total plant heat input from refinery fuel gas)

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
TN	Haywood Energy Center (Calpine)	900	12/21/2000		draft permit		SIP Approved	3	3	SW, GE 7FA or GE F7B	NG, FO	CC	8 760	3 5 ppm NG; 42 ppm FO	DLN/SCR; WI		varies from 7.4 to 50 ppm depending on CT type and load	GCP		
TN	TVA - Franklin	610	6/21/01		draft permit		SIP Approved	2	2	GE 7FA (195 MW)	NG	CC	8,760	3 5 ppm	SCR		25 ppm	GCP		
TN	Southern Power Co.	1,940	12/05/2001		applic. under review		SIP Approved	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	3 5/9 ppm NG; 12/42 ppm FO	SCR/DLN; SCR/WI		0 035 lb/mmbtu NG, 0 069 lb/mmbtu FO	GCP		
Region 5	164	114,444						586	222											
IL	ABB Energy Ventures - Bartlett	558	09/16/1999		09/05/2000	12	Delegated	2	?	2 at 279 MW	NG; FO	CC	8 760	?	SCR	?	?			
IL	Constellation Power - Holland Energy - Beecher City	336	10/07/1999		04/06/2000	6	Delegated	2	?	168 MW each	NG; FO	CC	8,760	?	SCR					
IL	Coastal Power - Fox River Peaking Sta.	345	11/19/1999		final review		Delegated	3	?	115 MW each	NG	SC	?	?	DLN					
IL	Peoples Gas, McDonnell Energy	2,500	06/21/1998		12/21/1998	6	Delegated	10	0	250 MW each	NG, ethane	CC	8,760	4.5 ppm	LNC, SCR	1-hr	15 ppm, 0 031 lb/mmBtu	GCP		BACT, Ox Cat rejected at $3043/ton
IL	Peoples Gas, McDonell Energy	680	06/21/1998		12/21/1998	6	Delegated	4	?	170 MW each	NG, ethane	SC	1,500	15 ppm	DLN	1-hr	15 ppm, 0 031 lb/mmBtu	GCP		BACT, operational
IL	Peoples Gas McDonell Energy	960	01/27/2000		10/17/2000	10	Delegated	5	?	172 MW each	NG	SC	?	?	DLN					
IL	Peoples Energy - Calumet Power LLC, Chicago	266	10/07/1999		12/13/1999	3	Delegated	2	?	133 MW each	NG	SC	?	?	WI					
IL	Calumet Energy LLC - Chicago	305	11/24/1999		05/18/2000	6	Delegated	2	?	152.5 MW each	NG; FO	SC	?		DLN					
IL	Illinois Power Tilton	176	?		01/01/1999		Delegated	4		44 MW	NG	SC	2 352	0 1 MMBtu	WI					Synth Minor; operating
IL	Indeck Pleasant Valley	?	?		01/28/1999		Delegated	2		150 MW	NG	SC	1,500	15 ppm	DLN					Synth Minor; rejected by county
IL	Indeck - Rockford	300	11/24/1999		02/16/2000	4	Delegated	2	?	150 MW each	NG	SC	?	?	DLN					
IL	Dynegy, Rock Rd. Power	277	12/04/1998		02/04/1999	2	Delegated	3		2 at121 MW & 1 at 35 MW	NG	SC	1,300	2 at 25 ppm and one at 42 ppm	2 on DLN and one withWI					Synth Minor, operational
IL	Dynegy, Rock Rd Power	121	5/99		10/27/1999	6	Delegated	1		121 MW	NG	SC	1,450	15 ppm	DLN					Synth Minor
IL	Indeck Libertyville	300	?		02/25/1999		Delegated	2		150 MW each	NG	SC	2,000	15 ppm	DLN					Synth Minor, awaiting city approval
IL	Soyland Power Alsey	105	12/06/1998		03/24/1999	4	Delegated	2		30 MW (2) & 22 5 MW (2)	NG; FO	SC	475							Synth Minor; under construction
IL	Soyland Power Alsey	45	12/09/1999		07/07/2000	7	Delegated	1		25 MW	NG; FO	SC	460		WI					Synth Minor, under construction
IL	LS Power, Kendall Energy	1,000	11/05/1998		06/02/1999	8	Delegated	4	4	250 MW each	NG, FO	CC	8,760	4.5 NG ppm/ 16 FO ppm	DLN, SCR	1-hr	33.1 ppm NG/49 6 ppm FO, 0 0626 w/DB, 0 0511no DB, >75% load	GCP		BACT; Ox Cat rejected at $4083/ton
IL	Union Electric, Gibson City Power	170	02/19/1999		06/16/1999	4	Delegated	2		135 MW each	NG; FO	SC	1,500	25 ppm NG; 42 ppm FO	DLN					Synth Minor, under construction
IL	Union Electric, Kinmundy Power	170	02/04/1999		06/28/1999	5	Delegated	2		135 MW ech	NG; FO	SC	1,500	9 ppm NG; 42 ppm FO	DLN					Synth Minor, under construction
IL	Reliant Energy (Houston Industries), Cardinal Woods Rivery Refinery	633	09/21/1998		07/14/1999	10	Delegated	3	3	211 MW each	NG, RFG	CC	8760, 1300 hrs with duct burners, more if load < 100%	3 5 ppm NG; 4 5 ppm RFG	SCR	8 hr/1 hr	0 0472 lb/mmBtu	GCP		BACT & LAER (NOx), Co-located with refinery, separate source Ox Cat rejected at $1993/ton
IL	Reliant Energy Shelby Energy Center	328	09/30/1999		02/01/2000	4	Delegated	8	?	8 at 41 MW each	NG	SC	?	?	WI					
IL	Reliant Energy Williamson Energy Center	328	09/30/1999		02/23/2000	5	Delegated	8	?	8 at 41 MW each	NG	SC	?	?	WI					

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
IL	Reliant Energy - DuPage County LP	935	11/03/1999		05/20/2000	7	Delegated	10	?	6 at 45 MW & 4 at 170 MW	NG	SC	?	?	6 with WI and 4 with DLN					
IL	Mid America, Cordova Energy Center	500	02/26/1999		09/02/1999	6	Delegated	2	0	250 MW each	NG	CC	8,760	4.5 ppm	SCR	1-hr	.0547 lb/mmBtu loads > 75%, after 9/2001	GCP		BACT; Ox Cat rejected at $1307/ton
IL	Enron, Des Plaines Green Land	664	02/03/1999		09/28/1999	7	Delegated	8	0	83 MW each	NG	SC	3,250	9/12/15 ppm	DLN	an/mo/hr	0 054 lb/mmBtu (>45F), .089 lb/mmBtu (<45F)	GCP		BACT; Ox Cat rejected at $6800/ton
IL	Enron, Des Plaines Green Land	167	04/03/2000		Pending		Delgated	1	?	167 MW	NG	SC	?	?	?	?	?	?		
IL	Reliant Energy, McHenry County Plant	510	05/26/1999		12/09/1999	5	Delegated	3		170 MW each	NG	SC	2,800 max (800 avg)	9 ppm	DLN					Synth Minor
IL	Enron, Kendall New Century	664	02/03/1999		01/14/2000	12	Delegated	8	0	83 MW each	NG	SC	3,300	9/12/15 ppm	DLN	an/mo/hr	0 054 lb/mmBtu (>45F), .089 lb/mmBtu (<45F)	GCP		BACT; Ox Cat rejected at $6700/ton
IL	CILCO - Medinia CoGen - Mossville	43	10/29/1999		05/30/2000	7	Delegated	3		3 at 14 2 MW each	NG	CC	?	?	DLN					
IL	Dominion Energy Lincoln Generation - Kincaid	688	2//3/00		in review		Delegated	4	?	4 at 172 MW each	NG	SC	?	?	DLN					
IL	LS Power, Nelson Project	1,000	-		-	-	Delegated	4		220 MW each	NG, FO	SC	8,760	25/15	DLN	1-hr				Synth Minor, minor until test under 15 ppm
IL	LS Power, Nelson Project	1,000	08/11/1998		01/28/2000	6	Delegated	4	4	250 MW each	NG; FO	CC	8,760	4.5 ppm NG, 16 ppm FO	SCR	1-hr	0 0626 w/DB, 0 0511no DB; >75% load	GCP		BACT, Ox Cat rejected at $3100/ton
IL	Ameren CIPS	600	08/30/1999		02/25/2000	6	Delegated	2	2	300 MW each	NG	CC	8,760	-	DLN, future SCR	-	0 06 lb/mmBtu	GCP	3 hr	BACT for CO and VOC only - netting out of NOx, PM and SO2 review; replacing coal boilers, Ox Cat rejected at $3400/ton
IL	Electric Energy - Midwest Electric Power Mossville	318	10/18/1999		03/29/2000	6	Delegated	5	?	3 at 72 MW each & 2 at 51 MW each	NG	SC	?	?	DLN					
IL	Holland Energy	680			draft permit		Delegated	2	2	680 MW	NG; FO	CC	8,760	4 5 ppm NG (3 5 ppm), 16 ppm FO (10 ppm)	SCR	1 hr (24 hr)	0.02, 0 04 FO, 0 12 NG w/DB	GCP	1-hr	BACT; SCR cost $8,900/ton, Ox Cat rejected at $10,600/ton
IL	Duke Energy - Lee Generating	664	09/13/1999		03/31/2000	7	Delegated	8	0	83 MW each	NG, FO	SC	2,000; 500 FO	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann); 1 hr		GCP	1-hr	BACT, SCR rejected at $27,689/ton, Ox Cat rejected at $6,931/ton
IL	Duke Energy - Kankakee	620	04/10/2000		draft permit		Delegated	2	?	620 MW	NG	CC	8,760							
IL	Duke Energy - Cook County	620	04/24/2000		under review		Delegated	2	?	620 MW	NG	CC	8,760							
IL	Constellation Power Univ Park	175	12/06/1999		05/01/2000	5	Delegated	2	?	175 MW	NG; FO	CC	?	?	SCR	?				BACT
IL	Rolls-Royce Power ventures - Lockport	294	05/01/2000		at notice		Delegated	6	?	6 at 49 MW each	NG	SC	?	?	DLN					
IL	Skygen Services - Zion Energy Center	800	11/12/1999		Final review		Delegated	5	?	160 MW each	NG, FO	SC	?	?	DLN					
IL	Soyland Power Alsey	100	12/06/1998		03/24/1999	4	Delegated	4	?	30 MW (2), 22.5 MW (2)	NG; FO	SC	?	?	2 with WI other 2 ?	?				
IL	Soyland Power Alsey	25	12/09/1999		07/07/2000	7	Delegated	1	?	25 MW	NG, FO	SC	?	?	Not given	?				Synth Minor
IL	Standard Energy Ventures - DuPage	800	12/01/1999		in review	?	Delegated	?	?	800 MW	NG	SC								
IL	Spectrum Energy - Logan County Power	135	05/05/2000		09/12/2000	4	Delegated	3	?	3 at 45 MW each	NG	SC	?	?	WI					
IL	Spectrum Energy - Central Ill. Power - St Elmo	45	06/16/1999		09/08/1999	3	Delegated	1	?	45 MW	NG	SC	?	?	DLN					
IL	Spectrum Energy - Central Ill. Power - St Peter	45	10/04/1999		02/01/2000	3	Delegated	1	?	45 MW	NG	SC	?	?	?					
IN	PSI - Fayette Peaking Station	520			12/18/1998		Delegated	4		4@45 or 2@170 MW	NG	SC	peaking	25 ppm	either DLN or WI		15 ppm	GCP		Syn. Minor

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
IN	PSI-Wabash Peaking Station	169			01/19/1999		Delegated	3		LM 6000 (43 MW)	NG, FO	SC	3,000	25 ppm NG; 28 ppm FO	DLN and WI		42 ppm NG, 6 ppm FO	GCP		Syn Minor
IN	Vermillion Generating Station	640	12/18/1998		06/01/2000	7	Delegated	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI	annual	25 ppm NG, 20 ppm FO	GEP	1-hr > 50% load	BACT; Usage limit of 20,336 MMCF NG-12 consec months Also 2 Emergency Generators; 1 Emergency Diesel Fire Pump, 4 Diesel Storage Tanks; SCR @ $19,309/ton (avg); Ox Cat @ 90% Control, rejected at $8,977/ton
IN	Cinergy Corporation	169			07/15/1999		Delegated	3		GE LM6000 (43 MW)	NG; FO	SC	3,000	25 ppm NG; 28 ppm FO	DLN and WI		42 ppm NG, 6 ppm FO	GCP		Synth Minor
IN	AES, Greenfield	520			07/15/1999		Delegated	4		4@45 or 2@170 MW	NG	SC	peaking	25 ppm	either DLN or WI		15 ppm	GCP		Synth Minor
IN	Indianapolis Power and Light	191			08/17/1999		Delegated	1		GE 7121EA (95 7 MW)	NG; FO	SC	peaking	25 ppm NG; 42 ppm FO	WI					Synth Minor
IN	Indianapolis Power and Light	265			09/17/1999		Delegated	3		GE (88 4 MW each)	NG	SC	peaking	25 ppm NG; 42 ppm FO	DLN	an/hr	25 ppm NG, 20 ppm FO	GCP		Synth Minor
IN	DeSoto Generating Station	?			applic. under review		Delegated	8		GE 7EA (80 MW each)	NG	SC	2,500	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.), 1 hr	25 ppm NG; 20 ppm FO	GCP		BACT
IN	West Fork Land Development (ENRON)	540			draft permit		Delegated	4		SW 501D5A (135 MW)	NG	SC	966	25	WI		12 ppm	GCP		Synth Minor
IN	Parke County	?			no appl. (10-99)		Delegated	2		225 MW?	NG, FO	CC	8 760	3 5ppm, ?? FO	DLN and SCR	an/hr	unknown			BACT
IN	Whiting Clean Energy	?			applic under review		Delegated	2		GE 7FA (166 MW)	NG	CC	8,760	3 ppm, 4 ppm w/DB	DLN and SCR		9 ppm <19 ppm w/duct burners	GCP		LAER
IN	LSP	?			applic under review		Delegated	4		200 MW?	NG; FO	EITHER	8,760	3 5 ppm, 4.5 w/DB, 16 FO	DLN/WI and SCR		33 1 ppm - 234.3 (50% load); 49 6 ppm - 168 ppm (50% load) FO	GCP		BACT
MI	Wyandotte Energy	500	application rececived 8/98		02/08/1999	2	Delegated	2	2	GE 7FA	NG	CC	8,760	4 5 ppm(33 lb/hr) NG/16 ppm FO	SCR	1 hr	3 ppm (LAER)	Cat Ox	1 hr	LAER; SCR cost $5600/ton * Time frame required by Michigan Law
MI	Sourthern Energy	1 000	application received 7/98		03/16/2000	2	Delegated	4	4	GE 7FA	NG	CC	8,760	3.5 ppm, 0 013 lb/mm btu	SCR	1 hr	0 042 lb/mm btu	GCP	1 hr	BACT
MI	KM Power Co	550	application received 3/00		06/26/2000	2	Delegated	7	7	1GE 7EA and 6 GE LM 6000	NG	CC	7380 and 4780	9 ppm and 22 ppm	DLN	30 day	79 lb/hr and 132 lb/hr	GCP	1 hr	BACT
MI	Covert Generating Co	1,200	application received 9/00		01/12/2001	2	Delegated	3	3	Mitsubishi 501 G	NG	CC	8,760	2 5	SCR	24 hr	33 7 lb/hr	Cat Ox	24 hr	BACT
MI	Indec Niles Energy Center	1076	application received 2/00		application under review		Delegated	4	4	Siemens V84 3A	NG	CC								
MI	Midland Cogeneration Venture	510	application received 1/00		application under review		Delegated	2	0	ABBK 24-1	NG	CC								
MI	Detroit Edison Co	250	application received 7/00		application under review		Delegated	3		GE PG7121(EA)										
MN	LSP-Cottage Grove	245	09/15/1995		11/10/1998	38	Delegated	1	1	Westinghouse 501F (245 MW)	NG; FO	CC	7,060 NG, 1,700 FO	4.5 ppm NG, 16 ppm FO	SCR	1-hr	1200 lb/hr, 1200 lb/hr FO	Cat Ox	1-hr	BACT
MN	Lakefield Junction	552			draft permit		Delegated	6		GE model PG7121EA (92 MW)	NG, FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI	3-hr	25 ppm NG; 20 ppm FO	GCP	3-hr	PSD; SCR rejected @ $11,500/ton; Ox Cat rejected at $3000/ton
MN	Pleasant Valley	444			draft permit		Delegated	3		SW V.84 3A & 501D5A (155 MW & 134 MW)	NG, FO		8,760	35 ppm NG; 42 ppm FO	DLN, WI		35 ppm NG; 35 ppm FO	GCP		PSD
MN	Xcel Energy (formerly NSP-Black Dog)	290	07/31/2000		01/12/2001	5.5	Delegated	1	1	Westinghouse 501F (290 MW)	NG	CC	8760; 1500 hr/yr for duct burners	4 5 ppm	DLN, SCR	3-hr	18 ppm; 25 ppm when duct burners operating, 400 tpy	GCP	3-hr	BACT/PSD
OH	Duke Energy Madison LLC	640	12/21/1998		07/01/1999	6	Delegated	8		GE 7EA (80 MW)	NG; FO	SC	2,500 NG; 500 FO	15 ppm (12 ppm) NG; 42 ppm FO	DLN	1 hr (ann)	25 NG 20 FO	GCP	hr/an	BACT, SCR rejected at $19,000/ton; Ox Cat rejected at $9000/ton

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OH	Duke Energy Washington, LLC	340	?		Jan-01		Delegated	2	2	GE 7EA (170 MW)	NG	CC	4260 W/O DB; 4500 W/DB	3.5 ppm	SCR	1 hr (ann.)	10 ppm w/o DB; 114 w/ DB	GCP	hr/an	PSD
OH	Duke Energy Madison II, LLC	640	?		-		Delegated	8		GE 7EA (80 MW)	NG, FO	SC	2,000 NG; 500 FO							PSD
OH	PS&G Waterford Energy	340	?		-		Delegated	2		GE 7EA (170 MW)		CC		3.5 ppm	SCR					
OH	Dresden Energy	340	?		-		Delegated	2		GE 7EA (170 MW)		CC		3.5 ppm	SCR					
OH	Rolling Hills Generating	1,045	?		-		Delegated	5		(209 MW)		SC		15 ppm	DLN					
OH	Jackson Generating	640	?		-		Delegated	4		GE 7EA (160 MW)	NG	SC		9 ppm	DLN					
OH	DP&L Tait Generating	?	?		-		Delegated					SC		9 ppm	DLN					
OH	Jackson Co. Power	640	?		-		Delegated	4		GE 7EA (160 MW)	NG	CC		5 ppm	SCR					
WI	RockGen Energy	525	09/01/1998		01/01/1999	4	SIP Approved	3		GE 7FA (175 MW each)	NG, FO	SC	3,800 Total, 800/CT FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst; 1 hr	12 ppm NG; 15 ppm FO (load>75%) & 24 ppm FO (load<75%)	DLN, GEP	1-hr	BACT; SCR not chosen; cost $23,018/ton, Ox Cat rejected at $15 K/ton
WI	Southern Energy	?	?		02/25/1999	?	SIP Approved	2		GE 7FA (180 MW each)	NG; FO	SC	8,760 Total, 699 FO	12/15 ppm NG; 42 ppm FO	DLN, WI	24 hr/inst; 1 hr	12 ppm NG; 15 ppm FO (load>75%) & 24 ppm FO (load<75%)/ 42 ppm FO	DLN, GEP	24-hr / 1 hr FO	BACT; Ox Cat rejected at $14 K/ton
WI	Wisconsin Public Service	360			07/01/1999		SIP Approved	1		GE 7EA (102 MW)	NG; FO	SC	4,000 Total, 2,000 FO	9 ppm NG; 42 ppm FO	DLN	hr, nat gas, FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	GEP	1-hr	BACT; SCR rejected at $13,866/ton; Ox Cat rejected at $6053/ton incremental cost
WI	Wisconsin Electric	85			draft permit		SIP Approved	1		GE 7EA (85 MW)	NG; FO	SC	178,000 MWhrs, 2,000 hrs, 100 hr power aug	9 ppm NG (20 ppm w/power aug.); 42 ppm FO	DLN	24-hr, 1-hr FO	25 ppm NG (100% load)/ 45 ppm (>75% load)/ 100 ppm (>60% load); 20 ppm FO	GEP	1-hr	BACT; SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost
Region 6																				
AR	Jonesboro City Water & Lights	56	?		?		SIP Approved	2		2 - 23 MW		SC								
AR	Jonesboro City Water & Lights	44	?		07/29/2001		SIP Approved	1		1 - 44 MW		CC								
AR	Hot Springs Energy	1,240	05/31/2000		12/29/2000	7	SIP Approved					CC								
AR	AES Cypress	540	12/11/2000		10/15/2001	11	SIP Approved					CC								
AR	Gen Power	640	01/31/2000		08/08/2000	7	SIP Approved					CC								
AR	Hot Springs Power	700	03/12/2001		11/09/2001	8	SIP Approved					CC								
AR	Pine Bluff Energy	220	09/04/1998		05/05/1999	8	SIP Approved	1				CC								
AR	Pine Bluff Energy - Mod	220	02/23/2000		02/27/2001	12	SIP Approved	1				CC								
AR	AR Electric - Fitzhugh Station	170	02/13/2001		02/15/2002	12	SIP Approved	1				CC								
AR	Union Generating Station	260	07/01/1999		08/24/2000	13	SIP Approved	10		260 MW		CC								
AR	Tenaska - KEO	1,800	09/18/2000		10/09/2001	13	SIP Approved					CC								
AR	KN Power	510	?		draft permit		SIP Approved	7		510 MW total		CC								
AR	Duke Energy Newport	620	06/05/2001		draft permit		SIP Approved					CC								
AR	Paragould Electric	4	?		draft permit		SIP Approved	4		4 MW total		SC								
AR	Plum Point	16K	04/20/2001		in review		SIP Approved				coal									
AR	Arkansas Electric Coop	153	11/19/1999		03/10/2000	4	SIP Approved	1				SC								
AR	Kinder Morgan - Newpot Power	560	07/02/2001		in review		SIP Approved	7	6	6-LM 6000/1-GE7EA		SC/CC								
AR	Wrightsville Energy Power facility	510	05/03/1999		02/28/2000	10	SIP Approved	7	6		NG	One CC, Six SC	8,760 in CC 5,250 in SC	9 ppm (DLN), 25ppm (SI)	DLN (CC), SI (SC)	?	50 ppm (DLN), 66 ppm (SI)	GCP	?	
AR	Genova	550	11/14/2001		in review		SIP Approved					CC								
LA PSD-LA-623	Nations Energy	800			voided?		SIP Approved			800 MW total		CC								

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LA	Wash Ph Energy Center - Bogalusa	800	11/12/1999		06/25/2000	7	SIP Approved			800 MW total		CC								
LA PSD-LA-651	Ouachita Power - Cogentrix Sterlington	800	11/12/1999		06/21/2000	7	SIP Approved			800 MW total	NG	CC		9 ppm	SCR/LNB					
LA	Caddo Parish Energy		06/25/2001		03/14/2002	9	SIP Approved													
LA	Cogentrix - Acadia	300	?		?		SIP Approved			300 MW total		SC								
LA	Calcasieu Power	370	?		10/21/1999		SIP Approved			370 MW total		CC								
LA PSd-LA-652	Entergy - Monroe	130	01/14/2000		06/16/2000	5	SIP Approved			130 MW Total	NG	steam driven	3000 each	0 110 lb/mmbtu	IFGR,RCSFS in boilers		NA	NA	NA	3 steam-driven turbines
La PSD-LA-645	Acadia Power Partners LLC	1,000	10/14/1999		07/13/2000	9	SIP Approved				NG	CC		9 ppm	SCR/LNB					
LA TV-LA-011VO	Entergy Gulf States LA Station2	140	05/24/2000		01/19/2001	8	SIP Approved			140 mw total	NG	steam driven	3000 each	0 100 lbs/mmbtu	?IFGR,RCSFS,BOOS in boilers		NA	NA	NA	3 steam-driven turbines
LA PSD-LA-633	Occidental Chemical - Taft	510	07/22/1998		03/19/1999	8	SIP Approved	3			NG	CC		8/25 ppm (w/waste gas)	SCR/SI					
LA PSD-LA-650	Occidental Chemical - Convent		?		06/08/2000		SIP Approved													
LA PSD-LA-637	PPG Industries		?		12/02/1999		SIP Approved													
LA TV-LA-002V2	Cleco Evangeline LLC		?		06/29/2000		SIP Approved													
LA	Duke Energy - Ruston		08/06/2000		07/10/2001	11	SIP Approved													
LA PSD-LA-638	Carville Energy				12/09/1999		SIP Approved													
LA	Bayou Cove Peaking Plant		04/16/2001		10/25/2001	6	SIP Approved													
La TV-LA-2136V1	Shell Chemical				applic under review		SIP Approved													
LA	Bayou Verrett		12/22/1999		11/15/2001	11	SIP Approved													
LA	LA Generating - Big Cajun	240	08/11/2000		12/08/2000	4	SIP Approved	2				CC		15 ppm	DLN					
LA	LA Generating - Big Cajun		09/01/2001		in review		SIP Approved					CC								
LA PSD-LA-622	AirLiquid America Co-Gen		10/08/1997		02/13/1998	4	SIP Approved	1	1	966 mm btu/hr	NG	CC	?	9 ppm	LNB, DLN	?	25 ppm	GCP		
LA	Formosa Plastics Corp Baton Rouge						SIP Approved					CC		9 ppm	DLN					
NM	El Paso Electric/Rio Grande Power Plant	261	?		final permit		SIP Approved			261 MW total										
NM	Lordsburg Limited/100 MW Repowering.	100	07/27/1995		06/18/1997	25	SIP Approved	1		WH 501D5A 100MW total	NG, FO	SC	1,440	15 ppm >75% output, 42 ppm <75% output 42 ppm/60 ppm FO	DLN, WI	?	10 ppm/200 ppm NG & 90 ppm/150 ppm FO per outputs listed for NOx	Clean fuels CO catalyst	?	
NM PSD-90-M2	TNP Lordsburg	220	11/03/1997		08/7/1998	9	SIP Approved	2	2	GE LM6000 Sprint aero-derivative	NG, FO	CC	7,360, 1,400 FO	15 ppm	SCR, WI	?	18 ppm	GCP	?	
NM	Lea County/North Lovington	50			shutdown		SIP Approved			49 5 MW total										
NM	Plains Electric/Escalante Plant	300			final permit		SIP Approved			200-300 MW total										
NM	PNM/San Juan.	1,798			final permit		SIP Approved			1798 MW total										
NM	Southwestern Public Service/Cunningham	511	08/09/1996		02/15/1997	6	SIP Approved			511 MW total	NG, FO									
NM	Southwestern Public Service/ Maddox	292			final permit		SIP Approved			292 MW total										
NM	Southwestern Public Service/Carlsbad	16			no TV permit required.		SIP Approved			16 MW total										
NM	Williams Field Services/Milagro	62			final permit		SIP Approved			62 MW total										
NM	Raton Public Service/Raton Plant.	11			draft permit		SIP Approved			11.25 MW total										
NM	Luna Energy Facility				12/29/2000															
NM	Energy SW - Las Cruces				01/08/2001															
OK	AECI-Chouteau	530	10/06/1998		03/24/1999	6	SIP Approved	2		530 MW total	NG	CC	8,760	12 ppm	DLN, SCR	?	10 ppm	GCP	?	NOx $2,535/ton
OK	Cogentrix -Jenks	800			10/01/1999		SIP Approved	3		800 MW total		CC								
OK	C&SW	320			10/18/1999		SIP Approved	2		320 MW total		CC								
OK	Panda - Coweta	1,000			01/21/2000		SIP Approved	4		1000 MW total		CC								

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OK	OG&E-Horsehoe	90			02/03/2000		SIP Approved	2		90 MW total		SC								
OK	Duke-Newcastle	520			01/21/2000		SIP Approved	2		520 MW total		CC								
OK	ONEOK -Edmond	360			05/01/2000		SIP Approved	4		360 total		SC								
OK	Redbud Energy - OK County	825	03/16/2000		08/15/2001	17	SIP Approved	3		825 MW total		CC								
OK	Energetix - Thunderbird	825	06/12/2000		05/17/2001		SIP Approved	3		825 MW total		CC								
OK	Kiowa Power	1,200			05/01/2001		SIP Approved	4		1200 MW total		CC								
OK	SmithCoGen -Lawton	600	06/13/2000		draft permit		SIP Approved	2		600 MW total		CC								
OK	SmithCoGen - Pocola	1,200	05/07/2000		08/16/2001	15	SIP Approved	4		1,200 MW total		CC								
OK	Energetix - Webbers Fall	825	11/20/2000		10/22/2001	11	SIP Approved					CC								
OK	KM Power - Pittsburg Pla	550	06/12/2000		05/13/2001	11	SIP Approved			6-LM6000/1-GE7EA		SC								
OK	WFEC - Anadarko	94			06/26/2000		SIP Approved					SC								
OK	Tenasca - Seminole	1200			withdrawn 10/25/01		SIP Approved					CC								
OK	Energetix GR. Plains	900			Pending Facility Action		SIP Approved					CC								
OK	Duke - Stephens	620	07/10/2001		12/10/2001	5	SIP Approved					CC								
OK	Mustang Power - Harrah	310	05/10/2001		02/13/2002	9	SIP Approved					SC		25	DLN					
OK	Horseshoe Energy	310	07/03/2001		02/13/2002	7	SIP Approved					SC		25	DLN		40	GCP		
TX	Sweeney Cogen Ltd Part - Brazoria	363	02/12/1996		09/09/1996	7	SIP Approved	3	?	3 W501D5A, 121 ME each			?	15/25	DLN	?	?	GCP	?	
TX	Sweeney Cogen Ltd Part - Brazoria	121	12/12/1997		09/30/1998	10	SIP Approved	1		121 MW				15 ppm	DLN					
TX	QUIXX Corp (SPS) - Hutchison	242	03/11/1996		02/05/1997	11	SIP Approved	2	?	2 W501D5A, 121 MW each			?	15	DLN	?	10	GCP	?	
TX	GSE&DCE LS Power LLC, Yoakum	550	12/31/1996		07/17/1997	7	SIP Approved	2	2	2 F7FA,, 180 MW each, 550 MW total		CC	?	15	DLN	?	?	GCP	?	
TX	Occidental Chemical Co	500	04/18/1997		01/08/1998	9	SIP Approved	2	2	2 F7FA, 170 MW each		CC	?	15	DLN	?	20	GCP	?	
TX	Gregory Power Partnership	336	05/09/1997		03/19/1998	10	SIP Approved	2		2 F7FA, 168 MW each		?	?	15	DLN	?	20	GCP	?	
TX	Houston Industries Power Gen	110	10/29/1997		04/01/1998	5	SIP Approved	2		2 F6B 44 MW each		CC	8,760	15	SCR	?	15	CatOx	?	
TX	BASF	83	12/08/1997		06/26/1998	7	SIP Approved	1		1 F7FA, 83 MW		?	?	9/5	DLN	?	25	GCP	?	
TX	Sweeney - Harris	240	04/01/1996		12/04/1996	8	SIP Approved	1		W501F, 160 MW, 240 MW total	NG, ?	CC	8,760	12	SCR, SI	?	20	GCP	?	
TX	Sweeney - Harris	121	12/10/1997		09/30/1998	11	SIP Approved	1		W501D5A 121 MW		?	?	15/25	DLN	?	10	GCP	?	Ammended to add Co-Gen
TX	Calpine Corp Harris	500	12/18/1997		09/30/1998	11	SIP Approved	1		W501F, 160 MW		CC	8,760	12/9	SCR	?	25	GCP	?	
TX	Edinburg Energy - Hiladgo	815	12/29/1997		08/18/1998	8	SIP Approved	4		4 ABB GT-24, 180 MW each, 815 MW total		CC	?	15	DLN	?	10	GCP	?	
TX	Frontera Generating L P - Hilalgo	440	02/12/1998		07/31/1998	7	SIP Approved	2		2 F7FA, 165 MW each, 440 MW total		CC	?	15	DLN	?	?	GCP	?	
TX	Lubbock Power & Light	128	03/19/1998		01/08/1999	9	SIP Approved	2		LM6000 (42 MW each with project total 128 mW)		CC		15 ppm	SCR		25 ppm	GCP		
TX	Midlothian Energy Ltd. (Venus)	1,080	04/13/1998		10/02/1998	6	SIP Approved	4		ABB-GT24 (175 MW)		CC		9/5 ppm	SCR		25 ppm	GCP		
TX	City Public Service	500	04/20/1998		10/14/1998	6	SIP Approved	2		GE 7FA (170 MW)		CC		9 ppm	SCR		25 ppm	GCP		
TX	Calpine Magic Valley	700	05/01/1998		12/31/1998	7	SIP Approved	2		SW501G (230 MW)		CC		12/9 ppm	SCR		25 ppm	GCP		
TX	Lamar Power Part (Panda Paris) (1000 MW total)	680	05/07/1998		10/28/1998	6	SIP Approved	4		GE 7FA (170 MW each)		SC		9 ppm	DLN		18 ppm	GCP		
TX	Union Carbide	39	05/29/1998		10/20/1999	5	SIP Approved	1		F6B (39 MW)				9 ppm	DLN		25 ppm	GCP		
TX	Duke Energy Hidalgo, LP	520	06/15/1998		12/22/1998	6	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm	GCP		
TX	Panda Guadalupe Power (1000 MW total)	1,000	06/24/1998		02/15/1999	8	SIP Approved	4		GE 7FA (170 MW)		SC		9 ppm	DLN		15 ppm	GCP		

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
TX	Fina/BASF (amend - Substitute) (78 MW total)	78	10/12/1998		04/22/1999	6	SIP Approved	2		F6B (39 MW each)		CC		9 ppm	DLN/SCR		25 ppm	GCP		Cogen for Boiler. N007 (VOC only,Nox 182f)
TX PSD-908	BASF Freeport Co-Gen	83	12/8/97 rev		06/26/1998	7	SIP Approved	1	1	83 MW	NG	CC	8760 turbibe 4380 duct burner	15 ppm duct burner off, 0.1 lb/mm btu duct burner off	DLN	?	25 ppm duct burner off, 0.008 lb/mm btu duct burner on	GCP	?	Revised to add Co-Gen
TX permit PSD-840	Brownsville Public Utility	?	12/4/97 rev.		01/09/1998	2	SIP Approved	1	1		NG, FO	CC		15.8 ppm NG/ 42 ppm FO See cell comments	Not in permit file	?	15 ppm NG/ 10 ppm FO	not in permit file	?	
TX PSD-857	Sweeny Co-Gen LTD Brazona	363	05/23/1996		09/09/1996	4	SIP Approved	3	3	121MW each W501D5A	NG/Refinery fuel	CC	8,760	15 ppm/25 ppm w/DB	?	?	10 ppm	GCP	?	
TX PSD-857	Sweeny Co-Gen LTD Brazona	121	12/12/1997		09/30/1998	10	SIP Approved	1	1	121 MW - W501D5A	NG/Refinery fuel	CC	8,760	15 ppm/25 ppm w/DB	?	?	10 ppm	GCP	?	
TX	Eastex Cogen	466	11/12/1998		11/19/1999	12	SIP Approved	2		GE 7FA (168 MW)		CC		9 ppm	DLN		7 ppm			
TX	Tenaska Gateway	880	12/02/1998		05/07/1999	6	SIP Approved	3		GE 7FA (164 MW)		SC		9 ppm	DLN		25 ppm			
TX PSD-897	Ternaska Frontier Shiro (Gnmes)	830	01/13/1998		08/07/1998	7	SIP Approved	3	3	830 MW total	NG; FO	?	?	15 ppm NG/ 42 ppm FO	DLN, SI	?	not given	not given	?	
TX PSD-739	Ternaska Frontier Lamar	830	01/13/1998		?	?	SIP Approved	3	3	830 MW total	NG; FO	?	?	15 ppm NG/ 42 ppm FO	DLN, SI	?	not given	not given	?	Not on TX list - canceled ?
TX	Hays Energy Project	1,080	12/02/1998		06/08/1999	6	SIP Approved	4		ABB-GT24 (175 MW)		CC		5 ppm	DLN/SCR		5 (25) ppm			
TX	Ennis-Tractabel Power Co., Inc	350	01/21/1999		12/15/1999	11	SIP Approved	1		SW501G (250 MW)		CC		9 ppm	SCR		20 ppm			
TX	Sabine River Works Cogen LP	440	02/01/1999		06/22/1999	5	SIP Approved	2		GE 7FA (170 MW)		CC		6 ppm	SCR		15 ppm			
TX	SEI - Texas, LLC	650	02/11/1999		03/21/2000	13	SIP Approved	4		2 GE 7FA (170 MW) / 2 GE 7EA (82 MW)		SC		9/9 ppm	DLN		9/25 ppm			
TX	SEI - Texas, LLC	650	02/11/1999		12/20/1999	10	SIP Approved	3		GE 7FA (170 MW)		SC		9 ppm	DLN		9 ppm			
TX	Mobil Oil	740	02/11/1999		03/14/2000	13	SIP Approved	3		SW501F (180 MW)		SC		9/9 ppm	DLN/SCR		10/25 ppm			
TX	Cogen Lyondell (CT #7)	180	03/04/1999		11/05/1999	8	SIP Approved	1		SW501F (180 MW)		SC		25 ppm	DLN		25 ppm			
TX	City of Garland	85	03/09/1999		02/23/2000	11	SIP Approved	1		GE 7EA (85 WM)		SC		9 ppm	DLN		25 ppm			
TX	Rio Nogales Power Project LP	780	03/17/1999		12/03/1999	8	SIP Approved	3		GE 7FA (170 MW)		SC		9 ppm	DLN		7.4 ppm			
TX	Odessa-Ector Power Partners LP	1,000	04/05/1999		11/19/1999	7	SIP Approved	4		GE 7FA (170 MW)		SC		9 ppm	DLN		9 ppm			
TX	Archer Power Partners LP	1,000	04/05/1999		01/13/2000	9	SIP Approved	4		GE 7FA (170 MW)		SC		9 ppm	DLN		9 ppm			
TX	AES Aurora	1,000	04/22/1999		02/07/2000	9	SIP Approved	4		GE 7FA (170 MW) / SW501F (183 MW)		SC		9 ppm	DLN		25 ppm			
TX	Freestone Power Project LP	1,070	04/30/1999		03/28/2000	11	SIP Approved	4		GE 7FA (175 MW)		SC		9 ppm	DLN		20 ppm			
TX	GenTex Power Corp & Calpine	500	05/21/1999		09/30/1999	4	SIP Approved	2		SW501F (180 MW)		SC		5 ppm	SCR		10/25 ppm			
TX	Duke Ennergy Kaufman	440	05/27/1999		01/27/2000	8	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm			
TX	Corpus Christi Cogeneration LP	708	05/28/1999		02/04/2000	8	SIP Approved	3		GE 7FA (166 MW)		SC		9 ppm	DLN		15 ppm			
TX	Duke Energy Bell LP	520	06/14/1999		02/04/2000	7	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm			
TX	Midlothian Energy (add #5 & #6)	550	07/01/1999		11/24/1999	5	SIP Approved	2		ABB-GT24 (175 MW)		CC		5 ppm	SCR		25 ppm			
TX	Gateway Power Project, LP	800	07/06/1999		03/20/2000	9	SIP Approved	3		GE 7FA (170 MW)		SC		9 ppm	DLN		7.4 ppm			
TX	Reliant Energy - Channelview	820	07/06/1999		12/09/1999	5	SIP Approved	4		SW501F (183 MW)		CC		3 ppm	DLN/SCR		23 ppm			N017 (NOx and VOC)
TX	Chambers Energy Facility - Harris	2,000	07/12/1999		08/11/2000	13	SIP Approved	8		ABB-GT24 (180 MW)		CC		3.5 ppm	SCR (LAER)		25 ppm	CatOx (LAER)		N019 (NOx and VOC)

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
TX	Coastal Power Company	550	07/28/1999		03/22/2000	8	SIP Approved	2		GE 7FA (170 MW)		SC		9 ppm	DLN		20 ppm			
TX	Cobisa-Forney, LP	1,774	07/29/1999		03/06/2000	7	SIP Approved	6		GE 7FA (170 MW)		SC		9 ppm	DLN		15 ppm			
TX	Calpine Corp. - Chambers	750	08/02/1999		02/11/2000	6	SIP Approved	3		SW501F (180 MW)				3.5 ppm	DLN/SCR		15 ppm			N020 (NOx and VOC)
TX	LG&E Power Inc	1,600	08/16/1999		08/18/2000	12	SIP Approved	6		GE 7FA (170 MW)		CC		9 ppm	SCR		15 ppm			
TX	Duke Power - Jack, LP	520	08/25/1999		03/14/2000	7	SIP Approved	2		GE 7FA (170 MW)				9 ppm	DLN		20 ppm			
TX	Calpine - Harris	740	08/26/1999		03/22/2000	7	SIP Approved	3		SW501F (180 MW)				3.5 ppm	SCR		25 ppm			N021 (NOx and VOC)
TX	Wise County Power Co., LLC	800	11/04/1999		07/14/2000	8	SIP Approved	2		SW501G (350 MW)		CC		5 ppm	SCR		9 ppm	CatOx		
TX	West Texas Energy LP	1,500	11/10/1999		07/28/2000	8	SIP Approved	6		ABB-GT24 (180 MW)		CC		5 ppm	SCR		5 ppm			N024 VOC (128f for NOx)
TX	Texas Industrial Power	193	11/24/1999		applic. under review		SIP Approved	1		GE 7FA (166 MW)		CC		3.5 ppm	SCR		30 ppm			N023 (NOx and VOC)
TX	Westvaco Texas	85	12/30/1999		12/15/2000	12	SIP Approved	2		LM6000 (42 MW)		CC		5 ppm	SCR		26 ppm			
TX	Cottonwood Energy Co., LP	600	03/30/2000		12/15/2000	9	SIP Approved	4		GE 7FA (170 MW) / SW501F (180 MW)		CC		5 ppm	SCR		17.6			
TX	Air Products	176	09/30/2000		12/19/2000	3	SIP Approved	4						15 ppm	DLN		25 ppm	GCP		
TX	Channel Energy	180	11/16/2000		In Review		SIP Approved	1				CC		3.5 ppm	SCR		25 ppm			
TX	Calpine Amelia	1,030	10/20/2000		In Review		SIP Approved	3				CC		2.5 ppm	SCR		22 ppm			
TX	Calpine Deer park	1,060	09/05/2000		08/22/2001	13	SIP Approved	4				CC		2.5 ppm	SCR		25 ppm			
TX	Cedar Power Partners	660	04/13/2000		12/21/2000	7	SIP Approved	2				CC		3 ppm	SCR		25 ppm	GCP		
TX	MC Energy Mont County	310	04/13/2000		06/20/2001	14	SIP Approved	2				CC		3 ppm	SCR		25 ppm	CatOx		
TX	So. Tx. Elec COOP	180	05/24/2001		01/17/2002	-		3		LM6000	NG			5	SCR		15	GCP		
TX	Hartburg Power	800	03/07/2001		In Review	-		3		GE 7FA	NG			5	SCR		15	GCP		
TX	TX Petrochem	900	11/13/2000		In Review	-		3		GE 7FA	NG			5	SCR		15	GCP		
TX	BP Amoco	550	10/16/2000		07/21/2001	-		3		GE 7FA	NG, FO			3.5	SCR		25	GCP		
TX	BP Amoco Chemical	70	10/24/2000		In Review	-		6		SW501F				3.5	SCR		25	GCP		
TX	Steag Power, LLC	1400	07/16/2001		Voided	-		4		SW501G				3.5	SCR		20	GCP		
TX	Brazos Valley Energy, LP	800	11/06/2000		In Review	-		2		Co-gens				3.5	SCR		25	GCP		
TX	Dow Chemical	1440	11/02/2000		In Review	-		6		SW501F				3.5	SCR		25	GCP		
TX	Texas Bayou Energy	25	11/22/2000		Voided	-		1		LM2500				4.2	SCR		25	GCP		
TX	OxyVinyls LP	87	11/10/2000		In Review	-		1		GE 7FA				4	SCR		25	GCP		
TX	Celanse	252	11/21/2000		In Review	-		6		LM 6000				5	SCR					
TX	Celanse		11/21/2000		Review					Six LM 6000 Comb Turbines				Good Comb. Practice						
TX	Ennis Tractabel	815	12/14/2000		On Hold	-		2		SW501G				5	SCR		9 ppm			
TX	City of Austin	500	05/30/2001		In Review	-		4		LM6000/GE 7FA				5.5	SCR		9/20 ppm			
Region 7																				
IA	MidAmerican Energy, Des Moines Power Station	610	10/24/2001	Currently in Public Review Period	Currently in Public Review Period		SIP Approved	2	2	SW 501FA (170 MW)	NG	CC	8,760	25 ppm (SC); 3 ppm (CC)	DLN (SC); SCR (CC)	24-hour	10 ppm (Phase I); 5 ppm (Phase II)	Oxidation Catalyst	24-hour	Phased project will start in simple cycle mode (without SCR) and move to combined cycle during transition period
IA	Hawkeye Generation, LLC (a division of Entergy)	580	10/01/2001		In Review		SIP Approved	2	2	GE 7FA	NG	CC	8,760	9 ppm (proposed), lower limit expected	DLN; SCR (likely)	24-hour	9 ppm	CC	short-term	Duct burning limited to 4,500 hours per year
KS	Western Resources	380	11/20/1998		06/11/1999	6	SIP Approved	3	0	2 - GE-7EA (100 MW each), 1 GE-7FA (180 MW)	NG, FO	SC		15 ppm NG, 42 ppm FO	DLN, WI					NOx limits are for > 70% load; NSPS limits will apply at < 70 % Load
KS	Duke Energy (Leavenworth County)	620	06/20/2001		02/07/2002	8	SIP Approved	2	2	2 - GE-7FA (310 MW each)	NG	CC	8,760	4.5 ppm	SCR, DLN	24-hour	16.9 ppm	GCP	short-term	
KS	Great Plains Power, Paola	320	06/06/2001		draft permit		SIP Approved	4	0	4 - GE-7EA (80 each)	NG; FO	SC	4,000 NG, 500 FO	9 ppm NG, 42 ppm FO	DLN	30-day rolling	25 ppm	GCP		
KS	Great Plains Power, Gardner	640	06/06/2001		In Review		SIP Approved	8	0	8 - GE-7EA (80 each)	NG, FO	SC	4,000 NG, 500 FO	9 ppm NG; 42 ppm FO	DLN	30-day rolling	25 ppm	GCP		
KS	Entergy	530	12/2001		In Review		SIP Approved	2	1	GE 7FA	NG	CC	8,760	3-5 ppm	SCR, DLN		TBD	TBD		

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
MO	Kansas City Power & Light - Hawthorn Unit 6	200	08/15/1995		01/10/1996	8	SIP Approved	1	0	Seimens V.34A (200 MW)	NG	SC	8,760	25 ppm	DLN	24-hour		GCP		
MO	AECI - Nodaway Units 1 & 2	200	07/27/1998		11/12/1998	4	SIP Approved	2	0	Westinghouse 501D (100 MW each)	NG	SC	2,000	25 ppm	DLN		90 ppm	GCP		
MO	AECI - Essex Unit 1 (synthetic minor)	100	issued		issued		SIP Approved	1	0	Westinghouse 501D	NG	SC								
MO	AECI - St. Francis Unit 1	250	02/04/1997		08/29/1997	7	SIP Approved	1	1	Seimens V.34A (250 MW)	NG; FO	CC	8,760	4.5 ppm NG	SCR, DLN, WI	3-hr	10 ppm NG	GCP		
MO	AECI - St. Francis Unit 2	266	06/04/1999		07/14/1999	8	SIP Approved	1	1	Seimans V84.3A (266 MW)	NG	CC	8,760	4.5 ppm	SCR		10	GCP		NOx $1,165/ton
MO	Empire District - Stateline Unit 2-1	150	07/12/1999		10/08/99	10	SIP Approved	1	1	SW 501F (150 MW)	NG	CC		4 ppm	SCR	30 day	10 ppm	GCP		recommissioned to CC
MO	Empire District - Stateline Unit 2-2	150	07/12/1999		10/08/99	10	SIP Approved	1	1	SW 501F (150 MW)	NG	CC		4 ppm	SCR	30 day	10 ppm	GCP		
MO	Kansas City Power & Light - Hawthorn Unit 6/9 (HRSG retrofit)	160	2/29/99		08/18/1999	6	SIP Approved	1	1	Seimens V.34A	NG	CC	8,760	5 ppm	SCR		25 ppm	GCP		Retrofit w/ duct burners, waste heat boiler and SCR
MO	Kansas City Power & Light - Hawthorn Units 7 & 8	150	2/29/99		08/18/1999	6	SIP Approved	2	0	GE 7EA (75 MW, each)	NG	SC	8,760	9 ppm	DLN		25 ppm	GCP		
MO	Duke Energy - Audrain	640	04/11/2000		05/09/2000	6	SIP Approved	8	0	GE 7EA (80 MW, each)	NG, FO	SC	2,500; 500 FO	12 ppm/9 ppm (NG), 42 ppm (FO)	DLN; WI	1-hr/annual	20 ppm NG; 25 ppm FO	GCP		
MO	Duke Energy - Bollinger	640	08/17/2000		09/22/2000	11	SIP Approved	8	0	GE 7EA (80 MW, each)	NG	SC	2,500	12 ppm/9 ppm	DLN	1-hr/annual	20 ppm	GCP		PM-10 0.016#/mmBtu, Formaldehyde, <10 TPY Each turbine limited to 2,500 hours on NG-only (annual rolling), with entire plant limited to 4,000 hours per year
MO	Utilicorp - Aquila Merchant, Pleasant Hill	600	06/04/1999		08/16/1999	8	SIP Approved	2	2	Seimens Westinghouse 501F (300 MW, each)	NG	CC	8,760	4.5 ppm	SCR	30 day	10 ppm (70-100%), 15 ppm (w/PA), 50 ppm (60-70%)	GCP	short-term	NOx - $2,500/ton
MO	Associated Electric Cooperative - Centralia	360	11/27/2000		02/13/2001	3	SIP Approved	3	0	Siemens V84.2 (120 MW, each)	NG; FO	SC	8,760	15 ppm NG/42 ppm FO	DLN	3-hr	35 ppm	GCP	short-term	Each turbine limited to 2,000 hours per year on N.G. and 500 hours on 0.05%S diesel; plant limited to 4,000 hours per year
MO	Kinder Morgan, LLC	530	Permit Tentatively Denied		Permit Tentatively Denied	Permit Tentatively Denied	SIP Approved	7	7	6 GE-LM6000; 1 GE-7EA, plus 120 MW supplemental duct firing	NG	CC	8,760							
MO	Panda Power - Montgomery Generating Station	1290	12/00		08/21/2001	8	SIP Approved	4	4	4 GE-7FA (170 MW), plus 510 Mwe supplemental duct firing	NG	CC	8,760	3.5 ppm	SCR	3-hr	7.3 ppm/13.9 ppm	GCP	24-hr	
MO	AmerenUE - Columbia Energy Center (synthetic minor)	192	Issued		Issued		SIP Approved	4	0	4 GE PG6581 (B)	NG	SC		Less than 91.8 tons Nox determined with CEMS	DLN	annual	17 lb/hr		Hourly	
MO	Utilicorp - Aquila Merchant, Pleasant Hill Aries II Project	341			In Review		SIP Approved	3	0	SW 501D5A (113 MWe, each)	NG	SC	2,500	Tentative, 15 ppm	DLN		Tentative, 25 ppm	GCP		Each turbine limited to 2,500 hours of operation per year
NE	Omaha Public Power - Sarpy Units 1, 2, 3, and 4	100	02/09/1999		07/29/1999	5	SIP Approved	4	0	Pratt & Whitney FT-8 (25 MW, each)	NG; FO	SC	2,000 each	25 ppm NG; 42 ppm FO	WI		69 lb/hr NG, 34 lb/hr FO	GCP		
NE	Lincoln Electric System Rokeby Unit 3	90	06/03/1999		11/22/1999	6	SIP Approved	1	0		NG, FO	SC	3,504	25 ppm NG; 42 ppm FO	DLN; WI/SI		not given	GCP		Fuel use limit on gas % oil

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
NE	Omaha Public Power, Cass County Station	346	09/06/2000		11/15/2001	14	SIP Approved	2	0	Seimens-Westinghouse 501F (173 MW, each)	NG	SC	2,500 each	20 ppm	DLN		15 ppm	GCP		BACT based on limitation of 2,500 hours per year of operation
NE	Lincoln Electric System, Salt Valley Station	153	Presently Under Review		Presently Under Review	Presently Under Review	SIP Approved	3		1-SC (45 MW) and 2-CC (54MW)		SC, CC								
NE	City of Grand Island, Burdick Station	80	07/01/2002		01/08/2002	6	SIP Approved	2	0	2 GE PG6581 (B), 40 MWe each		SC	5,000	15ppm NG/65 ppm FO						BACT based on limit of 5,000 hrs/yr on NG and 240 hrs/yr on FO
Region 8																				
CO	Colorado Energy Management (mod. to CO Power Partners/Brush Cogen) (+ 50 MW)	50	10/21/1998		05/25/1999	7	SIP Approved	2	none	1969 Westinghouse 251AA	NG		4,000 (both CTs)	30 ppm for first 24 months, then 25 ppm	custom low-NOx burners, WI	1-hr	60 ppm	GCP	1-hr	permit action also required NOx emission reductions on 2 other identical units from permitted 42 ppm immediately to 30 ppm and further to 25 ppm in 24 months
CO	Colorado Springs Utilities/Nixon (66 MW)	66	11/12/1998	11/98	04/19/1999	5	SIP Approved	2	none	GE PG6541(B) 33 MW each	NG	SC	8,660 (both CTs)	15 ppm	DLN	1-hr	?	Pollution prevention built into equip.		NOTE. this project was permitted 3 times - first in 4/95, then 7/98, and finally 4/99 Each time, the applicant modified and/or extended the project due to avalability of equipment, etc It is our understanding that the 4/99 configuration is being/has been installed
CO	Fulton Cogeneration/Manchief (284 MW)	284	06/07/1999 (note. original application under different ownership 4/99)	7/99	final 8/99	2	SIP Approved	2	none	SW V84.3A1, 142 MW rach	NG	SC	8,760	15 ppm	DLN	1-hr	10 ppm	GCP	1-hr	
CO	KN Energy/Front Range Energy Associates - Ft Lupton (160 MW)	160	11/99		on hold		SIP Approved	4	none	GE LM6000	NG	SC	**	25 ppm (proposed)	WI					project originally PSD application, State drafted syn minor permit w/ operating hours restrictions in 7/99, EPA commented to State concerning single source issue w/ adjacent PSCo facility, PSCo appealed to US 10th circuit court - currently
CO	Platte River Power Authority/Rawhide (82 MW)	82	3/00		12/00	9	SIP Approved	1	none	GE Frame 7EA	NG	SC	8,760	9 ppm	DLN					plan startup 5/2002; CO PTE below significance level so didn't do BACT; characterized as peaking plant, but not restricted in operating hours
CO	Public Service Co of Colo /Ft. St. Vrain Unit 4 (242 MW)	240	01/00		06/19/2000	6	SIP Approved	1	1	GE PG7241 (FA)	NG	SC/CC	8,760	4 ppm (CC); 9 ppm (SC)	DLN+SCR (CC); DLN (SC)	24-hr	9 ppm (CC & SC), 20 ppm (CC w/ DB)	GCP	1-hr	plan startup 6/2001;
CO	Front Range Power Project/Ray Nixon Sta , Fountain, CO (480 MW)	480	11/99, updated application 5/00		11/00	6	SIP Approved	2	2	GE Frame 7	NG	SC/CC	8,760	9 ppm/16 ppm w/ DB	DLN		25 ppm	GCP	1-hr	plan to begin construction 1/01, operation 7/02, PSD mod to existing Colo Springs Utils/Nixon coal-fired power plant; revising application to net out of PSD for NOx using reductions at coal-fired unit; applicant calculated PTE using 95% ca
CO	TriState Generation & Transmission/Limon Station (164 MW)	164	7/00		1/01	6	SIP Approved	2	none	GEF7EA, or equiv	NG, FO (1000 hr, each turbine, limit on FO)	SC	8,760	9 ppm (42 ppm on FO)	DLN (plus WI on FO)	1-hr	25 ppm	GCP		

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
CO	WestPlains Energy, Pueblo (304 MW)	304	5/00		12/00	7	SIP Approved	1	1	(TBD - APPEARS TO BE GE FRAME 7 EQUIVALENT)	NG	CC	8,760	4 ppm	SCR	daily				Company first obtained permit from State in 8/95; subsequently modified project and repermitted in 6/96, modified permit again to change location of project in 8/98; this most recent revision again changed equipment configuration - State reevaluated BACT and other PSD requirements with the 12/00 permit
CO	North Amer. Power Group/Kiowa Creek (1000MW)	1,000	05/00		01/01	8	SIP Approved	4	4	GE7FA or equivalent	NG	CC	8,760	4 ppm (proposed)	SCR		23 2 ppm	GCP	1-hr	plan to begin construction spring 2001, operation spring 2004; proposed project may trigger 112(g)
SD	Black Hills Power & Light/Lange CT Facility (80 MW)	80	12/02/1999	########	10/10/2000	2	Delegated	2		GE LM6000PD - 40 MW each	NG	SC	8,760	25ppm	DLN	24-hr	25 ppm	GCP		Characterized as peaking plant, but not restricted in operating hours. EPA commented negatively on the NOx BACT.
WY	Black Hills Power & Light/Niel Simpson II (80 MW)	80	09/15/1999		final 3/00	5 5	SIP Approved	2		GE LM6000PD	NG	SC	8 760	25 ppm	DLN	24-hr	25 ppm	GCP	1-hr	Region provided written comment disagreeing w/ NOx BACT determination; characterized as peaking plant, but not restricted in operating hours
WY	Two Elk Generation Partners (33 MW turbine)	33	10/31/1996		02/27/1998	26	SIP Approved	1		GE LM5000	NG	SC	8,760	25 ppm	DLN	1-hr	25 ppm	GCP	1-hr	Facility is 250 MW coal-fired steam electric plus 33 MW NG CT, characterized as peaking plant, but not restricted in operating hours
Region 9																				
AZ	Calpine - South Point Generating Station	500	06/15/1998	?	5/24/99 (EPA)	13	Delegated	2		500 MW total	NG; FO	CC		3 ppm	SCR	3-hr	10 ppm NG; 35 ppm FO	oxy cat		
AZ	Griffith Energy, LLC	650	10/26/1998		7/99	9	Delegated	2	2	650 MW total	NG; FO	CC	8,760	3 ppm	SCR, LNB	?	20 ppm	CTG	?	$1 555/ton NOx
AZ	Reliant Energy - Desert Basin Generating Project	580					Delegated	?	?	580 MW total	NG, ?	CC	8,760	3 ppm	SCR	24-hr	24 ppm		3-hr	
CA # SG-98-01	LaPalemoa generating Co LLC	1,048	7/16/98		7/27/99 EPA permit	12	Delegated & SIP approved by District	4	?	172 MW each, 262 with HRSG & STG each, ABB turbines		CC	8,760	2.5 ppm	see cell comments	1-hr	10 ppm	oxy cat		
CA	AES Antelope Valley	1,000	?		?		Delegated & SIP approved by District			1000 MW total										
CA	Blythe Energy	520	05/05/2000	########	?		Delegated & SIP approved by District			520 MW total		CC		2.5 ppm	SCR	1 hr	10 ppm >80%; 20 ppm @ 70-80%	?	3-hr	Delayed tue to section 7 ESA consultation & resource constraints
CA	Delta Energy Center - Calpine and Bechtel	880	?		10/21/1999		Delegated & SIP approved by District			880 MW total		CC	8,760	2.5 ppm	SCR	1-hr	10 ppm	Cat Ox	3-hr	Pollutant Trading - 1:1 VOC for NOx (nonattainment) 4:1 SO2 for PM10 (attainment)
CA	Sempra/OXY - Elk Hills	720	?		?		Delegated & SIP approved by District			680-720 MW total										
CA	OXY & Sempra Energy, Elk Hills Power LLC (joint venture)	500	01/09/1999		08/23/1999	7.5	Delegated & SIP approved by District			500 MW total		CC	8,760	2.5 ppm	SCR;	3-hr	4 ppm	CatOx	24-hr	Pollutant Trading - NOx for PM10, PSD Permit must be issued by EPA
CA	Elk Hills Power project		09/13/1999	########	Est early 2001															
CA	Pastoria Power project		12/10/1999	########	2/01	13														
CA	High Desert Power Project LLC	700	01/30/1998	########	draft 7/99		Delegated & SIP approved by District			700 MW total		CC	8,760	2 5 ppm	SCR	1-hr	4 ppm	CatOx	24-hr	

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
CA	US Generating - La Paloma	1,048	07/10/1998	########	7/27/99 (EPA)	11	Delegated & SIP approved by District	4		ABB (262 MW)		CC	8,760	2.5 ppm	SCR or SCONOx	1-hr				
CA	Long Beach District Energy Facility (ENRON)	500	?		?		Delegated & SIP approved by District			500 MW total										
CA	Calpine and Bechtel - Metcalf Energy	600	?		?		Delegated & SIP approved by District	2		600 MW total, 2 @ 200 MW + HRSG										
CA	Midway Sunset Cogeneration Co	500	02/22/2000	########	Est early 2001		Delegated & SIP approved by District			500 MW total							6 ppm	CatOx	3-hr	Trading NOx for PM @ 2 2/1
CA	Duke Energy - Moss Landing	1,206	?		05/12/2000		Delegated & SIP approved by District	2		2 @ 530 MW, 2 @ 15 MW (1260 MW total)	NG	CC		2 5 ppm	SCR/DLN	1-hr	9 ppm	GCP	3-hr	AFC submitted to CEC on 5/7/99, Monterey Bay unified APCD to issue ATC early 2000; 2 x 15 MW upgrade SteamTurbine rotor when SCR is added
CA	Duke Energy - Morro Bay	530	11/03/2000		?		Delegated & SIP approved by District			530 MW total										
CA	Calpine and Bechtel - Newark Energy Center	600	?		?		Delegated & SIP approved by District			600 MW total										
CA	PG&E Generating - Otay Mesa	510	?		6/00		Delegated & SIP approved by District			510 MW total		CC		2 ppm	SCONOx/SCR backup					Pollutant Trading - VOC reduc for NOx inc ; District plans to issue PDOC in March 2000
CA	Pastoria Power Project	750	?		5/15/00 ?		Delegated & SIP approved by District			750 MW total		CC		2.5 ppm	XONON/SCR Backup	1-hr	6 ppm	CatOx		Pollutant Trading - NOx in lieu of PM10
CA	Pittsburg District Energy Facility (ENRON)	500	?		06/10/1999		Delegated & SIP approved by District			500 MW total		CC		2.5 ppm	SCR	1-hr	6 ppm	CatOx	3-hr	
CA	AES South City	550	?		?		Delegated & SIP approved by District			550 MW total		SC/CC								
CA	Sunlaw Cogen Partners	800	?		?		Delegated & SIP approved by District			800 MW total		CC		1 -2 ppm	SCONOx	1-hr	1 -2 ppm			
CA	Texaco Global - Sunrise Cogeneration	320	?		pending		Delegated & SIP approved by District			320 MW total		CC		2 5 ppm	SCR	1-hr	6 ppm			
CA	Calpine - Sutter Power	500	01/22/1998	########	12/02/1999	9.0	Delegated & SIP approved by District			500 MW total		CC		2.5 ppm	SCR	1-hr	4 ppm		1 hr	EPA PSD permit - permit delayed due to applicant changes, citizen appeal to EAB
CA	Campbell Cogen	?	?		?		Delegated & SIP approved by District													
CA	Ogden Pacific Power - Three Mountain Power	500	01/01/1999		applic. under review		Delegated & SIP approved by District			500 MW total		CC		2 5 ppm	SCR	1-hr	4 ppm	CatOx	3-hr	Sinificant ESA problems
NV	Nevada Power Co.	475	?		?		Delegated & SIP approved by District	2		2 @ 235.5 each		CC	8,760	3.5 ppm	SCR	1-hr	2.6 ppm	CatOx		
NV permit # ?	El Dorado Energy	346	03/13/1997		08/21/1997	5	Delegated	2	2	165 MW each turbine, 173 MW each duct burner	NG, FO	CC	8760 4000 FO	3 5 ppm	SCR with ammonia injection (LAER)	?	2.6 ppm	oxy cat (LAER)	?	
HI	Ecogen	46	12/19/1994		06/09/1998	42	Delegated	2	?	46 MW total	Naphta, LSFO, gaoline	SC/CC		15 ppm	WI, SCR	?	57 5 ppm	?		
HI	Maui Electric	40	8/8/94		01/06/1998	43	Delegated	2	?	40 MW total	FO	SC		42 ppm	WI	?	44 ppm	?		
Region 10																				

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permiting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
ID, Permit 055-00040	Rathdrum Project (Avista - formerly Washington Water Power)	180			?		Minor NSR	2		GE 7EA	NG	SC	16,848 combined	235 5 TPY	DLN		240 TPY	GCP		Operating as peaking unit, Start-up 01/01/95, no minor NSR BACT
ID, Permit 055-00045	Rathdrum Power (Avista / Cogenerix)	270			10/29/1999		Minor NSR	1	1	GE 7FA	NG	CC	8000 - CT, 2000 - DB	4 5 ppmdv w/ DB, 3.4 ppmdv w/o DB	DLN, SCR	24-hr	92 3 TPY	CatOx		Operating, commercial operation began September 2001, www.avista com, www cogentrix com, no minor NSR BACT
ID, Permit 039-00024	Mountain Home Power Station (Idaho Power Company)	90	03/20/2001		09/14/2001	6	Minor NSR	2	0	SW 251B12A	NG	CC	10,332 combined	30 ppmdv, 248 TPY	DLN		30 ppmdv, 159 TPY	GCP		Operating, commercial operation began September 2001, no minor NSR BACT
ID, Permit 027-00081	Garnet Energy (Ida-West Energy)	535	06/19/2000		10/19/2001	16	SIP Approved	2	2	SW 501F	NG;FO	CC	8760	3 / 2 5 ppmdv - NG, 6 ppmdv - FO	DLN/SCR	24-hr / 12-month for gas, 24-hr for oil	5 / 2 ppmdv - NG, 6 ppmdv - FO	CatOx	1-hr / 12-month for gas, 1-hr for oil	Permit may be appealed by local citizen's group, www ida-west com/garnet htm, start-up 2004
ID	North Idaho Power (Cogentrix) - Rathdrum	810	08/15/2001		Under review		SIP Approved	3	3	GE 7FA	NG	CC	8760	2 5 ppm	DLN/SCR		2 ppm	CatOx		Permit application under review
OR, Permit 25-0031	Coyote Springs 1 (Portland General Electric / Avista)	250	01/19/1993		04/04/1994	14	SIP Approved	1	0	GE 7FA	NG;FO	CC	8760	4.5 / 15 ppmdv gas / oil	DLN/ SCR	24-hr	15 / 20 ppmdv gas / oil	GCP	8-hr	Operating, 03/12/97 permit revision
OR, Permit 25-0031	Coyote Springs 2 (Portland General Electric / Avista)	280	01/19/1993		04/04/1994	14	SIP Approved	1	0	GE 7FA	NG;FO	CC	8760	4.5 / 15 ppmdv gas / oil	DLN/ SCR	24-hr	15 / 20 ppmdv gas / oil	GCP	8-hr	Constructing, www avista.com, start-up June 2002, 03/12/97 permit revision
OR, Permit 30-0113	Hermiston Generating Plant (US Generating - PG&E Generating)	474	05/27/1993		07/07/1994	13	SIP Approved	2	0	GE 7FA	NG	CC	8760	4 5 ppmdv	DLN, SCR	24-hr	15 ppmdv	GCP	8-hr	Operating, start-up July 1996, www gen pge com
OR, Permit 30-0118	Hermiston Power Project (Calpine)	546	08/10/1994		08/28/1995	12	SIP Approved	2	2	SW501FD2	NG	CC	8760	4 5 ppmdv	DLN, SCR	24-hr	15 ppmdv	GCP	8-hr	Operating, 04/13/99 permit revision, start-up April 2002, www calpine com
OR, Permit 18-0003	Klamath Energy (Pacificorp Power Marketing)	484	03/01/1996		01/27/1998	23	SIP Approved	2	2	SW501F	NG	CC	8760	4 5 ppmdv	DLN, SCR	24-hr	15 ppmdv	GCP	8-hr	Operating, commercial operation began July 2001, www klamathcogen com, Power Magazine's Plant of the Year
OR, Permit 37-0436	Klamath Expansion Project (PacifiCorp Power Marketing)	100	04/30/2001		06/22/2001	2	SIP Approved	4	0	2 Pratt & Whitney FT-8 (Twin Pac)	NG	SC	8760	25 ppmdv	WI	24-hr	16 ppmdv	GCP	8-hr	Operating, permit expires 24 months after start-up
OR, Permit 05-0011	Clatskanie People's Utility District	10	07/19/2001		11/01/2001	4	Minor NSR	1	0	GE/Nuevo Pigone 10B	NG	CC			NA			NA		
OR, Permit 05-0008	Port Westward (Portland General Electric)	650	05/14/2001		01/16/2002	8	SIP Approved	2	2	GE 7FB or SW 501S	NG	CC	8760	25 ppmdv	DLN,SCR	8-hr	4 9 ppmdv	CatOx	8-hr	
OR, Permit 30-0007	Umatilla Generating (PG&E)	580	04/17/2001		01/18/2002	9	SIP Approved	2	2	GE 7FB	NG	CC	8760	25 ppmdv	DLN,SCR	3-hr	6.0 ppmdv	CatOx	24-hr	
OR	Westward Energy (serving Goldendale Aluminum @ The Dalles)	540	09/07/2001		Under review		SIP Approved	2	2	SW V84 3A2	NG	CC	8760		DLN/SCR					
OR	Grizzly Power (Cogentrix)	980	12/03/2001		Under review		SIP Approved	4	4	GE 7FA	NG	CC	8760	25 ppmdv	DLN,SCR	24-hr	4.0 ppmdv	CatOx	8-hr	
OR	WANAPA (Williams)	1,200			Application expected summer 2002		EPA (tribal land)	4	4		NG	CC	8760							
WA, PSD-X80-02	Whitehorn (Puget Sound Energy)	187			12/19/1979		EPA	2	0	GE 7E	NG;FO	CC	8760	NSPS GG	WI			GCP		Operating
WA, PSD-X80-17	Frederickson (Puget Sound Energy)				09/25/1980		EPA	2	0	GE 7E	NG;FO	CC	8760	NSPS GG	WI			GCP		Operating
WA, PSD-X82-09	Fredonia (Puget Sound Energy)	228			08/23/1982		EPA	2	0	SW WF01D	NG;FO	CC	8760	NSPS GG	WI			GCP		Operating

National Combustion Turbine List

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WA, SCAPCA	Northeast Combustion Turbine (Avista - formerly Washington Water Power)	66	Initial NOC - 1/13/1978, NOC #1065 - 1/19/01, NOC #1092 - 1/25/02		Initial NOC - 1/20/1978, NOC #1065 - 4/24/01, NOC #1092 - pending	7	Minor NSR (BACT)	2		2 - Pratt & Whitney FT4C-3F (Twin-Jet Power Pac)	NG/FO	SC	Initial NOC & SCAPCA Order #95-12 - 500, NOC #1065 - none, NOC #1092 - ng (4000), FO (120)	NOC #1092 NG- 75 44 lb/MMft3, FO - 21.3 lb/1000 gal, SCAPCA Order #95-12 (VEL) - 95 ton/yr	DLN		NOC #1092 NG - 45 77 lb/MMft3, FO 6.93 lb/1000 gal, SCAPCA Order #95-12 (VEL) - 24 ton/yr	CatOx		Operating, Order #95-12, un-numbered, 1065, and 1092, peaking unit, NOC's #1065 and #1092 are for adding the DLN/CO control equipment to existing equipment, in order to allow Avista to operate the units more hours per year and remain a synthetic minor.
WA, SCAPCA Order 95-12	Northeast Combustion Turbine (Avista - formerly Washington Water Power)	66					Minor NSR (BACT)	2	0	Pratt & Whitney FT4C-3F	NG; FO	SC								Operating
WA, NWAPA 475 & 476	March Point Cogeneration	120			10/26/1990		Minor NSR (BACT)	3	3	GE Frame 6		CC	8760		WI/SCR			GCP		Operating
NWAPA Order 304	Sumas Cogeneration (Calpine & NESCO)	120			06/25/1991		Minor NSR (BACT)	1			NG	CC	8760	6 ppmdv			6 ppmdv			Operating, http://www.calpine com/energy_assets_4/calpine_4_2_3 asp?plant=8
PSD 91-02	Encogen Northwest Limited Partnership	123			07/31/1991		Joint Issuance: EPA & Ecology	3	0	GE Frame 6	NG; FO	CC	8760	7 / 11 ppmdv gas / oil	SCR	24-hr	10 ppmdv	GCP	1-hr	Operating
WA, PSD 91-04	Tenaska Ferndale	248			05/29/1992		Joint Issuance: EPA & Ecology	2	2	GE 7EA	NG,FO	CC	8760	7.0 / 12 ppmdv gas / oil	DLN, SCR	24-hr	20.0 ppmdv	GCP	1-hr	Operating, www.tenaska com, 1/19/00 permit revision, permit revision needed to allow installation of fogger to increase output 20 MW
WA, SWCAA 95-18000	River Road (Clark County PUD)	248	07/06/1995		10/25/1995	3	Minor NSR (BACT)	1	0	GE 7FA	NG	CC	8760 / 120 FO	3 4 / 8 0 ppmdv gas / oil - 24-hr	DLN, SCR	4 0 / 9 0 ppmdv gas / oil - annual	6 0 ppmdv gas or oil	CatOx	1-hr	Operating, www clarkpublicutilities.com
NWAPA Order 762a	Puget Sound Refining (previously Equilon)	35	02/26/2001	#######	04/11/01 with revision 02/22/02		Minor NSR (BACT)	7		Solar Taurus 60	NG	SC	8760 (changed to 2880 hour per turbine)	25 ppmvd	DLN	24-hr	30 ppmdv		24-hr	Operated during energy crisis; turbines not presently in use .
WA, PSD	BP Cherry Point Refinery (previously Arco)	73	02/16/2001				Delegated	14		Solar Taurus 60	NG	SC	8760	25 ppmvd	DLN	24-hr	50 ppmdv		24-hr	Order to operate; operated during energy crisis but not in use presently, no final permit yet issued
NWAPA Order 770	Georgia-Pacific West (tissue plant)	20	04/13/2001		05/31/2001		Minor NSR (BACT)	2		Solar Mars 100 & Solar Mars 90	NG	SC	8760	5 ppmvd	SCR	3-hr	7 ppmdv	CatOx	3-hr	Operated during energy crisis; turbines not presently in use
PSCAA NOC 7016	Everett Delta Generation (FP&L)	248			10/30/1997		Minor NSR (BACT)	1		GE 7FA	NG; FO	CC	8760	3 5 / 3 5 ppmdv gas / oil	DLN/SCR	8-hr	3 5 / 3 5 ppmdv gas / oil	CatOx	8-hr	Constructing, startup October 2002
WA, PSCAA NOC 7968	Frederickson Power (West Coast Energy)	248			03/25/2000		Minor NSR (BACT)	1	0	GE 7FA	NG; FO	CC	8760	3 0 / 13 ppmdv gas / oil	DLN, SCR	8-hr	7.0 / 7.0 ppmdv	CatOx	8-hr	Constructing, www.tenaska com, start-up May 2002, formerly BPA's Tenaska II, minor NSR BACT applies
WA, SWCAA 01-2342	Mint Farm Generation (Mirant)	319			12/04/2001		Minor NSR (BACT)	1	0	GE 7FA	NG	CC	8760	3 0 ppmdv/ 2 5 ppmdv	DLN, SCR	1-hr / annual	6 0 ppmdv/ 2 0 ppmdv	CatOx	1-hr / annual	Construction began October 2001
WA, SWC/	Longview Energy Development (Enron)	248					Minor NSR (BACT)	1		GE Frame 7FA, SW 501F, or (2) GE Frame 6FA	NG	CC	8760	3.0 ppmdv/ 2.5 ppmdv	DLN, SCR	1-hr / annual	6 0 ppmdv/ 2 0 ppmdv	CatOx	1-hr / annual	Not yet constructing
WA, Ecology Order No. 01AQCR-2037	Goldendale Energy Project (Calpine)	249			02/23/01		Minor NSR (BACT)	1	1	GE 7FA	NG	CC	8760	2 ppmdv	DLN, SCR	3-hr	2 ppmdv	CatOx	1-hr	Constructing, minor NSR BACT applies, startup July 2002
WA, EFSEC/95-02	Chehalis Power (Tractebel)	520	01/10/2000		04/17/2001	15	Joint Issuance: EPA & EFSEC	2	0	GE 7FA	NG; FO	CC	8760 / 720 FO	3.0 / 14 0 ppmdv gas / oil	DLN/SCR	1-hr	3 0 / 8 0 ppmdv gas / oil	CatOx	1-hr	Constructing, startup November 1, 2003

National Combustion Turbine List

State	Facility	# of New MW	Application Date	App. Comp Date	Final Permit Issued	Time to Final Permit	Permitting Status	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	CO Limit	Control Method	Avg. Time	Comments
WA, PSCAA NOC 8473	Pierce Power	160			07/03/2001		Minor NSR (BACT)	7	0	GE TM2500 (mobile LM2500)	NG	SC	8760	9 ppmdv	DLN, SCR	24-hr	10 ppmdv	CatOx	1-hr	Operating, startup August/September 2001, minor NSR BACT applies, permit expires April 2003
WA, Ecology Order No. 01AQIS-3151	Cliffs Energy Project (GNA Energy)	225			09/11/2001		Minor NSR (BACT)	5	0	GE LM6000	NG	SC	8760	4.5 ppmdv	DLN/SCR	3-hr	10 / 6 ppmdv	CatOx	3-hr / annual	Minor NSR BACT applies
WA, BCAA No. 2001-0013	Finley Combustion Turbine Project (Benton County PUD)	27			10/26/2001		Minor NSR (BACT)	1	0	Pratt & Whitney FT8-1 (Power Pac)	NG	SC	8760	5.0 ppmdv	WI/SCR	Inst	10 ppmdv	CatOx	Inst	Operating, minor NSR BACT
WA, PSCAA NOC	Tahoma Energy Center (Calpine)	270					Minor NSR (BACT)	1		GE 7FA	NG	CC	8760							Startup summer 2002 as 170 MW SC, converted to CC summer 2003
WA, EFSEC/2001-01	Satsop (Duke Energy & Energy Northwest)	650	04/23/2001		11/02/2001	6	Joint Issuance: EPA & EFSEC	2	2	GE 7FA	NG	CC	8760	2.5 ppmdv	DLN/SCR	1-hr	2.0 ppmdv	CatOx	1-hr	Constructing, startup November 1, 2002
WA, BCAA (NOC No TBD)	Plymouth Generating Facility	307	04/24/2001		Under review		Minor NSR (BACT)	1	??	Siemens Westinghouse Model 501F	NG	CC	8760	2.0 ppmvd (proposed)	DLN/SCR	3-hr	2 ppmdv and 10 ppmdv	CatOx	1-hr and @ partial load	
WA, PSD-01-01 & SWCAA 01-2350	TransAlta Centralia Generation - Big Hanaford Project	268	03/26/2001		02/22/2002	9	Delegated, Minor NSR (BACT)	4	4	GE LM6000	NG	CC	8760	3.0 ppmdv	DLN/SCR	3-hr	3.0 ppmdv/ 1.8 ppmdv	CatOx	1-hr/ 8-hr	Constructing, minor NSR BACT, startup July 2002
WA, PSD	Puget Sound Energy - Fredonia	110	10/23/2001		Under review		Delegated	2		2 - Pratt & Whitney FT8 (Twin Pack)	NG	SC			SCR			CatOx		Constructing via enforcement bridge
WA	Starbuck (NW Power Ent)	1,200	08/30/2001		Review temporarily suspended at request of applicant		Joint Issuance: EPA & EFSEC	4	4		NG	CC	8760		DLN/SCR			CatOx		
WA	Satsop Phase 2 (Duke Energy & Energy Northwest)	650	11/19/2001		Under review		Joint Issuance, EPA & EFSEC	2	2	GE 7FA	NG	CC	8760		DLN/SCR			CatOx		On-line expected November 1, 2003
WA	Sumas Energy 2 (NESCO)	660	10/01/2001		Under review		Joint Issuance, EPA & EFSEC	2		SW501F	NG	CC	8760	2.0 ppmdv	DLN/SCR	3-hr	2.0 ppmdv	CatOx		
WA	Mercer Ranch (Cogentrix)	800			Review temporarily suspended at request of applicant		Joint Issuance: EPA & EFSEC				NG	CC	8760							
WA	Wallula Power (Newport Northwest Generation)	1,300	09/10/2001		Under review		Joint Issuance EPA & EFSEC	4	4		NG	CC	8760		DLN/SCR			CatOx		
National Totals =	**636**	**340,699**						**1,648**	**407**											

If completeness date not given, then application date used in "Time to Final Permit" calculation.

* Except for power plants

Abbreviations:

GE = General Electric
SW = Seimens Westinghouse

NG = Nat. Gas
FO = Fuel Oil
DB = Duct Burner

SC = Simple Cycle
CC = Combined Cycle

DLN = Dry-Low NOx
WI = Water Injection
SCR = Selective Catalytic Reduction

CatOx = Catalytic Oxidation
GCP = Good Combustion Practices

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ATTACHMENT H

Table B-3. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA Combined Cycle Combustion Turbine
(3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,040,044	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$124,484	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$62,403	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$52,002	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,373,438	$16,492,225	
Direct Installation Costs			
Foundation and supports	$109,875	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$192,281	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$54,938	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$27,469	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$13,734	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$13,734	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$432,031	$4,967,668	
Total Capital Costs (TCC)	$1,805,470	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$137,344	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$68,672	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$137,344	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$27,469	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$13,734	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$41,203	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$475,766	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,281,236	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-3a. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA Combined Cycle Combustion Turbine
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Capital Costs			
Pollution Control Equipment	$1,391,170	$14,750,000	Vendor Estimates
Ammonia Storage Tank	$124,484	$0	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	$69,725	Vatavauk,1990
Instrumentation	$50,000	$50,000	Additional NO_x Monitor and System
Taxes	$83,470	$885,000	6% of SCR Associated Equipment and Catalyst
Freight	$69,558	$737,500	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,763,188	$16,492,225	
Direct Installation Costs			
Foundation and supports	$141,055	1,319,378	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$246,846	2,308,912	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$70,528	659,689	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$35,264	329,845	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$17,632	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$17,632	164,922	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	$5,000	Engineering Estimate
Buildings	$15,000	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$548,956	$4,967,668	
Total Capital Costs (TCC)	$2,312,144	$21,459,893	Sum of TDCC, TDIC and RCC
Indirect Costs			
Engineering	$176,319	$1,649,223	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	$0	Engineering Estimate
Construction and Field Expense	$88,159	$824,611	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$176,319	$1,649,223	10% of TDCC; OAQPS Cost Control Manual
Start-up	$35,264	$329,845	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$17,632	$164,922	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$52,896	$494,767	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$596,588	$5,112,590	
Total Direct, Indirect and Capital Costs (TDICC)	$2,908,732	$26,572,482	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-3b. Capital Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA Combined Cycle Combustion Turbine (2.0 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Basis of Cost Component
Direct Capital Costs		
Pollution Control Equipment	$1,553,048	Vendor Estimates
Ammonia Storage Tank	$124,484	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$50,000	Additional NO_x Monitor and System
Taxes	$93,183	6% of SCR Associated Equipment and Catalyst
Freight	$77,652	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$1,942,872	
Direct Installation Costs		
Foundation and supports	$155,430	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$272,002	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$77,715	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$38,857	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$19,429	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$19,429	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$602,862	
Total Capital Costs (TCC)	$2,545,734	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$194,287	10% of Total DirectCapital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$97,144	5% of TDCC; OAQPS Cost Control Manual
Contractor Fees	$194,287	10% of TDCC; OAQPS Cost Control Manual
Start-up	$38,857	2% of TDCC; OAQPS Cost Control Manual
Performance Tests	$19,429	1% of TDCC; OAQPS Cost Control Manual
Contingencies	$58,286	3% of TDCC; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$652,290	
Total Direct, Indirect and Capital Costs (TDICC)	$3,198,024	Sum of TCC and TInCC

Sources: Engelhard 2000. ABB Alstom 2000. EPA 1990, 1992 and 1996 (OAQPS Cost Control Manual). Golder 2000. Vatavuk 1990 (Estimating Costs of Air Pollution Control).

Table B-4. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation (3.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$96,501	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$21,867	$32,800	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$199,151	$298,726	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$10,621	$11,237	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$364,668	$385,819	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$321,312	$642,625	0.3% output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$349,344	$1,452,009	
Indirect Annual Costs			
Overhead	70,818	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	22,812	265,725	1% of Total Capital Costs
Insurance	22,812	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	250,480	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$366,922	$3,474,942	
Total Annualized Costs	$1,080,934	$5,312,771	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness (9 to 3.5)	$4,879	$23,979	per incremental ton of NO_x Removed
	221.56	221.56	tons NOx removed /year; 3.5 ppmvd corrected to 15% oxygen

Source: Golder 2000. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-4a. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(2.5 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Costs for SCONOx™	Basis of Cost Component
Direct Annual Costs			
Operating Personnel	$18,720	$37,440	24 hours/week at $15/hr for SCR; SCONOx 2 times SCR costs
Supervision	$2,808	$5,616	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$110,781	$0	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	$0	Engineering Estimate
Inventory Cost	$30,162	$45,243	Capital Recovery (10.98%) for 1/3 catalyst for SCR; SCONOx 1.5 times SCR
Catalyst Cost	$274,702	$412,053	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$13,565	$15,011	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$465,739	$515,363	
Energy Costs			
Electrical	$28,032	$70,080	80kW/h for SCR @ $0.04/kWh times Capacity Factor; 200 kW for SCONOx
MW Loss and Heat Rate Penalty	$372,722	$648,213	0.35% output for SCR; 0.6% for SCONOx; EPA, 1993
Steam Costs for SCONOx	$0	$690,567	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	$48,737	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$400,754	$1,457,597	
Indirect Annual Costs			
Overhead	79,386	25,834	60% of Operating/Supervision Labor and Ammonia
Property Taxes	29,087	265,725	1% of Total Capital Costs
Insurance	29,087	265,725	1% of Total Capital Costs
Annualized Total Direct Capital	319,379	2,917,659	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$456,939	$3,474,942	
Total Annualized Costs	$1,323,432	$5,447,902	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness (3.5 to2.5)	$7,397	$4,122	per incremental ton of NO_x Removed
	254.34	254.34	tons NOx removed /year; 2.5 ppmvd corrected to 15% oxygen

Source: Golder 2000. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-4b. Annualized Cost for Selective Catalytic Reduction and SCONOx™ for the GE Frame 7FA in Combined Cycle Operation
(2.0 ppmvd corrected for gas firing)

Cost Component	Costs for SCR	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$31,200	40 hours/week at $15/hr for SCRs
Supervision	$4,680	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$117,921	$300 per ton for Aqueous NH_3
PSM/RMP Update	$15,000	Engineering Estimate
Inventory Cost	$39,408	Capital Recovery (10.98%) for 1/3 catalyst for SCR
Catalyst Cost	$358,911	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	$17,014	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$584,135	
Energy Costs		
Electrical	$28,032	80kW/h for SCR @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	$401,641	0.375% output for SCR
Steam Costs for SCONOx	$0	17,795 lb/hr 600 °F, 85 psig, steam (1,329 Btu/lb steam); 90% boiler eff.; $3/mmBtu
Natural Gas for SCONOx	$0	80 lb/hr; 0.044 lb/scf; 1,020 Btu/scf; $3/mmBtu
Total Energy Costs (TEC)	$429,673	
Indirect Annual Costs		
Overhead	92,281	60% of Operating/Supervision Labor and Ammonia
Property Taxes	31,980	1% of Total Capital Costs
Insurance	31,980	1% of Total Capital Costs
Annualized Total Direct Capital	351,143	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDICC
Total Indirect Annual Costs (TIAC)	$507,384	
Total Annualized Costs	$1,521,191	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness (2.5 to 2.0)	$12,064	per incremental ton of NO_x Removed
	270.74	tons NOx removed /year; 2.0 ppmvd corrected to 15% oxygen

Source: Golder 2000. EPA 1993 (Alternative Control Techniques Document--NOx Emissions from Stationary Gas Turbines, Page 6-20)

Table B-5. Comparison of Alternative BACT Control Technologies for NOx on One CT/HRSG

	Alternative BACT Control Technologies		
	DLN Only	DLN with SCR (3.5 ppmvd corrected)	DLN with SCONOx™ (3.5 ppmvd corrected)
Technical Assessment	Feasible	Available, Feasible and Demonstrated	Not Demonstrated
Economic Impact [a]			
Capital Costs	included	$2,281,236	$26,572,482
Annualized Costs	included	$1,080,934	$5,312,771
Cost Effectiveness (per ton of Nox removed)			
Total	NA	$4,879	$23,979
Environmental Impact [b]			
Total NOx (TPY)	336	114.7	114.7
NOx Reduction (TPY)	NA	-222	-222
Ammonia Emissions (TPY)	0	112	0
PM Emissions (TPY)	0	9.8	0
Secondary Emissions (TPY)	0	6.2	41.3
Net Emission Reduction (TPY)	NA	-94	-180
Addition Greenhouse Gas (as CO2; tons/year)	0	3,414	22,905
Energy Impacts [c]			
Energy Use (kWh/yr) - Total	0	5,232,523	35,108,528
Energy Use (kWh/yr) - Back Pressure	0	4,531,723	9,063,446
Energy Use (kWh/yr) - Other	0	700,800	26,045,082
Energy Use (Equivalent Residential Customers/year)	0	436	2,926
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	53,900	361,652
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	54	362
Energy Use (percent of combustion turbine output)	0	0.35%	2.32%

[a] See Tables B-3, B-4, and B-5 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-7.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty and electrical usage for the SCR operation at 8,760 hours per year. Lost energy for SCR is based on 0.3 percent of 166 MW. SCR electrical usage is based on 0.080 MWh per SCR system. Lost Energy for SCONOx™ includes 0.6 percent of turbine output and steam usage. SCONOx™ electrical usage based on 0.2 MW/hr per system.

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™

	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
Pollutants	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	9.78	0.20	9.97		1.31	1.31
Sulfur Dioxide		0.07	0.07		0.49	0.49
Nitrogen Oxides	-221.56	3.59	-217.96	-221.56	24.11	-197.45
Carbon Monoxide		2.16	2.16		14.47	14.47
Volatile Organic Compounds		0.14	0.14		0.95	0.95
Ammonia	111.82					
Total:	-99.96	6.16	-93.80	-221.56	41.32	-180.23
Carbon Dioxide (all energy requirements)		3,413.67	3,413.67		22,904.63	22,904.63

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	53,900	361,652 total	245,607 steam and natural gas only

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6a. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) and SCONOx™ (2.5 ppm)

Pollutants	Incremental Emissions (tons/year) of SCR			Incremental Emissions (tons/year) of SCONOx™		
	Primary	Secondary	Total	Primary	Secondary	Total
Particulate	9.78	0.22	10.00		1.31	1.31
Sulfur Dioxide		0.08	0.08		0.49	0.49
Nitrogen Oxides	-254.34	4.09	-250.25	-254.34	24.16	-230.18
Carbon Monoxide		2.45	2.45		14.50	14.50
Volatile Organic Compounds		0.16	0.16		0.95	0.95
Ammonia	111.82					
Total:	-132.75	7.01	-125.73	-254.34	41.42	-212.93
Carbon Dioxide (all energy requirements)		3,886.71	3,886.71		22,956.05	22,956.05

Basis:	SCR	SCONOx™	SCONOx™
Lost Energy (mmBtu/year)	61,369	362,464 total	245,607 steam and natural gas only
Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.			
Particulate	0.0072		
Sulfur Dioxide	0.0027		
Nitrogen Oxides w/LNB	0.1333		
Carbon Monoxide	0.0800		
Volatile Organic Compounds	0.0052		

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6b. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction (SCR) (2.0 ppm)

Pollutants		Incremental Emissions (tons/year) of SCR		
		Primary	Secondary	Total
Particulate		9.78	0.24	10.02
Sulfur Dioxide			0.09	0.09
Nitrogen Oxides		-270.74	4.37	-266.36
Carbon Monoxide			2.62	2.62
Volatile Organic Compounds			0.17	0.17
Ammonia		111.82		
	Total:	-149.14	7.49	-141.65
Carbon Dioxide (all energy requirements)			4,152.79	4,152.79

Basis:	SCR
Lost Energy (mmBtu/year)	65,570
Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.	
Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

(Note: Seconary emissions of criteria pollutants for SCONOx based on the total lost energy minus steam and natural gas since emissions of these pollutants will be controlled in the proposed unit. Emissions of CO_2 will result for all uses.)

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-8. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$758,000	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$75,800	10% of SCR Associated Equipment
Sales Tax	$45,480	6% of SCR Associated Equipment/Catalyst
Freight	$37,900	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$961,685	
Direct Installation Costs		
Foundation and supports	$76,935	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$134,636	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$38,467	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$19,234	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$9,617	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$293,506	
Total Capital Costs	$1,255,191	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$62,760	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$125,519	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$25,104	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$12,552	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$37,656	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$389,109	
Total Direct, Indirect and Capital Costs (TDICC)	$1,644,300	Sum of TCC and TInCC

Table B-9. Annualized Cost for CO Catalyst GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$219,667	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$24,668	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$7,545	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$259,056	
Energy Costs		
Heat Rate Penalty	$214,208	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
Total Energy Costs (TDEC)	$214,208	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$16,443	1% of Total Capital Costs
Insurance	$16,443	1% of Total Capital Costs
Annualized Total Direct Capital	$180,544	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$217,736	
Total Annualized Costs	$691,000	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$4,409	per ton of CO Removed
	$4,819	per ton of Net Emission Reduction

Table B-10. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG

	Alternative BACT Control Technologies	
	DLN Only	DLN with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,644,300
Annualized Costs	included	$691,000
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$4,409
Environmental Impact [b]		
Total CO (TPY)	184	27
CO Reduction (TPY)	NA	-155
Net Pollutant Reduction	NA	-143
Additional Greenhouse Gas (CO2; tons/yr)	--	1,971
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,021,149
Energy Use (Equivalent Residential Customers/year)	0	252
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	31,121
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	31

[a] See Tables B-8 and B-9 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-11.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year.
Lost energy is based on 0.2 percent of 166 MW.

Table B-11. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst

Pollutants	Incremental Emissions (tons/year) of SCR		
	Primary	Secondary	Total
Particulate	9.78	0.11	9.89
Sulfur Dioxide		0.04	0.04
Nitrogen Oxides	0.00	2.07	2.07
Carbon Monoxide	-156.7	1.24	-155.5
Volatile Organic Compounds		0.08	0.08
Total:	-146.9	3.56	-143.4
Carbon Dioxide (additional from gas firing)		1,971.0	1,971.0

Basis:

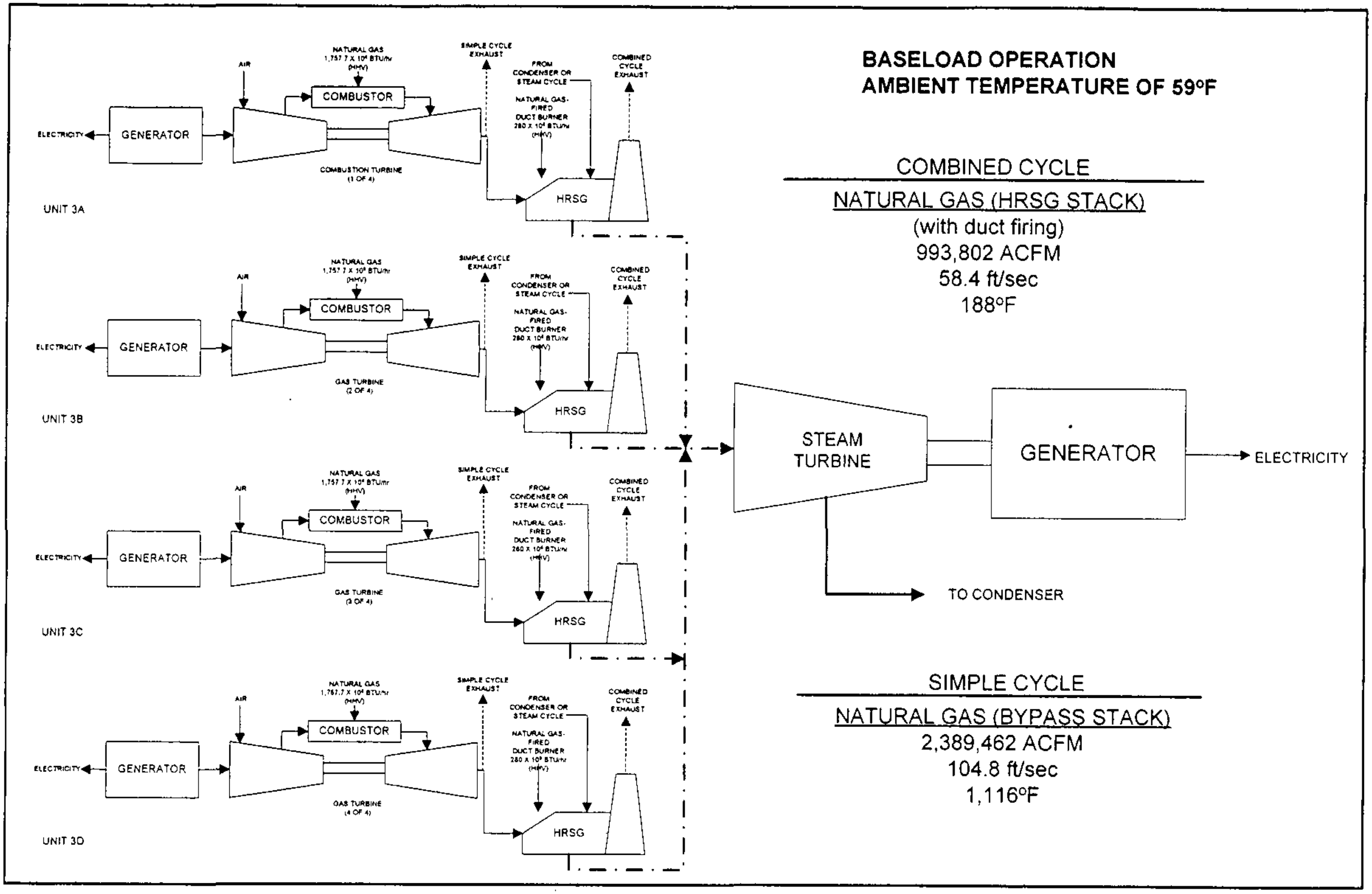
Lost Energy (mmBtu/year)	31,121

Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.

Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

ATTACHMENT I



Attachment I. Process Flow Diagram
Baseload Operation, Ambient Temperature of 59°F, Natural Gas
HRSG = Heat Recovery Steam Generator

Process Flow Legend
Solid/Liquid
Gas
Steam

FPL
Manatee Unit 3

TO: Hamilton B. Oven
Power Plant Siting Coordinator

THROUGH: Clair Fancy
Al Linero
Bureau of Air Regulation

FROM: Teresa Heron T.H.
Deborah Galbraith DG.
Bureau of Air Regulation

DATE: April 5, 2002

SUBJECT: FPL Manatee Power Plant
DEP File 0810010-006-AC (PSD-FL-328)

The following information is needed in order to continue processing this application:

1. Minor Sources: The application only lists the combustion turbines (CT), heat recovery steam generator (HRSG) and fuel heaters (FH). What will be the auxiliary equipment for this project (i.e cooling tower, fire pump)? Submit emissions estimates for these minor sources and include these emissions as part of the PSD applicability review.

2. Natural Gas and Sulfur Dioxide Emissions: Please revise and submit sulfur dioxide emissions. Proposed sulfur dioxide emissions are calculated based on an emission factor of 2 grains sulfur/100 scf pipeline natural gas. Recent BACT determinations have considered an emission factor of not more than 1.5 grains sulfur/100 scf. When would the gas supplier be selected?

3. Heat Recovery Steam Generator: What is the maximum steam production rate (lb steam/hr) from each HRSG? What is the capacity (MW) of the steam generator? What is the model and manufacturer of the duct burners and HRSG, if already selected? Submit the manufacturer performance emissions data sheets if available. Provide supporting documents and/or calculations of the expected emissions levels for the combined gas turbine exhaust and the duct burner emissions.

4. High Power Modes of Operation: Please expand details of the operations (temperature, % load, power output) under the requested modes of power augmentation, fogging, and peak. What is the manufacturer's maximum recommended period (hr/yr, hr/month) for operation under each of these modes?

5. Automated Control System: What type of control system is recommended by the combustion manufacturer (i.e. Mark V control system, etc).

6. Start Up and Shutdown Emissions: Please submit a Best Operating Practice procedure for minimizing emissions during start up and shutdown (cold, warm, hot, simple cycle, and combined cycle). What is the proposed number of startup/shutdowns?. Estimate the pollutants emissions during this period. Describe the "steam blow" process and explain the requested length of time (90 days). Please provide supporting documentation.

7. Maximum Achievable Control Technology for HAPS: Do the proposed emissions rates for these pollutants include emissions during startup and shutdowns? Please explain.

8. BACT for Carbon Monoxide: On the BACT economic analysis, what is the basis (i.e., vendor's quote, capital recovery data) of the values given for the oxidation catalyst (OC). Provide us with the names of all manufacturers that were contacted along with their estimates while developing capital and annualized cost estimates for this project. Total proposed annualized cost per unit of $691,000 appears to be higher than annualized cost for recent combined cycle projects reviewed by the Department (i.e. Cana at $355,941 and El Paso at $485, 927). The cost effectiveness (dollar/ton) is also lower for those projects (i.e. Cana at $2,852 and El Paso at $ 2,475) compared to the proposed cost of $4,409 for this project. Please recalculate the CO economic analysis. Describe what alterative was used in the economic analyst, the installation of the catalyst prior to the HRSG or within the HRSG (page 4-15 of the application)?

   The requested CO BACT emission rates of 24.5 ppmvd @ 15% O_2 (duct burning), 29.5 ppmvd @ 15% O_2 (duct burning and high power modes [HPM] of operation) do not represent current CO BACT control levels. At these levels, the Department believes that an oxidation catalysis may be cost effective. Please comment.

   Provide supporting documentation that duct burning and HPM operations would increase emissions from 7.4 ppmvd @ 15% O_2 (GE guarantee) to 24.5 ppmvd @ 15% O_2 (duct burning) and to 29.5 ppmvd @ 15% O_2 (HPM)?

   Other states, including New York, Massachussets, New Jersey, Arizona, Connecticut, Washington, and California have enforced BACT standards by permitting a large number of gas-fired combined and simple cycle power plants with CO limits of 2 to 6 ppmvd @ 15% O_2 averaged over 3 hours and achieved using oxidation catalyst. Continuous compliance is demonstrated using CEMs, based on 3 hour averages. Please comment.

   Oxidation catalysts are technically feasible and can be cost effective for both simple cycle and combined cycle applications. They are also essential to control toxic emissions, particularly from simple cycle turbines that experience a large number of startups. Please comment.

9. CO Emissions Increase or Decrease: What would be the overall increase or decrease in emissions for the facility as a result of applying the oxidation catalyst technology in the new units?. The application states that " *the end results is an additional 1,970 TPY of carbon dioxide (CO_2).* Please submit an explanation of this statement (compare the decrease (in tons per year) of the operation of the new units with oxidation catalyst versus the increase of the operation of the older units as a result of supplying needed energy). Refer to page 4-16 of the application.

10. BACT for NO_X: Appendix B, Tables for hot SCR appears to be missing. Please submit.

   Other states, including New York, Connecticut, Illinois and California have enforced BACT standards by permitting a large number of gas-fired simple cycle peaking power plants with NOx limits of 2 to 6 ppmvd @ 15% O_2 averaged over 1 to 3 hours and achieved using high temperature selective catalytic reduction (SCR). Continuous compliance is demonstrated using CEMs, based on 1 hour to 3 hour averages. Please comment.

Please evaluate the cost effectiveness of reducing NOx emissions to 2.0 ppmvd @ 15% O_2 by SCR. Other states, including New York, Connecticut, Masachussaets, Rhode Island, New Jersey, Arizona, Washington and California have enforced BACT standards by permitting a large number of gas-fired combined cycle power plants with NOx limits of 1.55 to 2.5 ppmvd @ 15% O_2 averaged over 1-hour and achieved using SCR. Continuous Compliance is demonstrated using CEMs, based on 1-hour average. Please comment.

11. BACT Social Impacts: Expand the BACT analysis to include the social impact of the application of selective catalytic reduction (SCR) and oxidation catalysis (OC)?

12. Energy Replaced: How much energy (MW) from these new units will replace energy from the older, less efficient units?

13. Emission Offset: Is FPL considering to reduce emissions from the old units as a result of the operation of the new units? If so, how would this be accomplished?. Please explain.

14. Flow Diagram: Include a flow diagram representative of the project, including all 4 units, stacks, HRSG & duct burners, etc.

15. Gas Fired Heaters: Please describe when fuel gas heating is necessary (application page 2-3). Why will these heaters operate only during the simple cycle mode? Is there a separate heat transfer system used during the combined cycle mode?

16. Additional Comments: Comments from EPA and Manatee County will be forwarded when received.

17. Air Quality Analysis: Rule 62-212.400(3)(h)(5) states that an application must include *information relating to the air quality impacts of, and the nature and extent of, all general commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect.* Please satisfy this rule requirement as it relates to the Manatee Expansion facility.

18. In the application submitted, Table F-2, the first footnote about the meteorology data does not correspond with the meteorology information throughout the remainder of the application. Please verify that the footnote is incorrect.

19. The *Additional Impact Analysis* analyses the effects PM, PM10, SO_2, NOx, CO and sulfuric acid mist, all pollutants subject to PSD review, have on soils, vegetation, wildlife and visibility. Please include VOC emissions in your analysis since it is also subject to PSD review.

20. A pre-construction ambient monitoring analysis for ozone, based on VOC emissions, was required as part of the application for the Manatee Expansion. Please elaborate on the analysis you submitted.

21. What are the ozone readings from Manatee County? How far away from FPL Manatee is the Port Manatee monitor? How many exceedances have Manatee ozone monitors had in the past year? Why do you think the Expansion will not contribute to a violation of the standard?

22. Are there any fugitive emissions created from the Expansion? If so, please address them.

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 Al Linero (P.E. Administrator) at 850/921-9519. Matters regarding modeling issues should be directed to Deborah Galbraith (meteorologist) at 850/921-9537 and e-mail deborah.galbraith@dep.state.fl.us. Matters regarding the technical information may be directed to Teresa Heron (review Engineer) at 850/921-9529 and e-mail teresa.heron@dep.state.fl.us

U.S. FISH AND WILDLIFE SERVICE
AIR QUALITY BRANCH

P.O. BOX 25287, Denver, CO 80225-0287

FACSIMILE COVER SHEET

Date: March 19, 2002

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

To: Theresa Heron, FDEP
Cleve Holladay, FDEP

From: Ellen Porter

Subject: Manatee Power Project, PSD 328

Comments attached. No problem with Class I modeling analyses. However, we have comments on NOx limit. Letter will follow with our Regional Director's signature.

Number of Pages: 8
(Including this cover sheet)

Office Location: 7333 W. Jefferson, Room 450, Lakewood, CO 80235

(Send Mail to: 12795 W. Alameda Parkway, Lakewood, CO 80228)

Re: PSD-FL-328

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for Florida Power and Light Company's (FPL) combined cycle project at the Manatee Power Plant in Manatee County, Florida. The facility is located 115 km south of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed. Specifically, we recommend that your department require FPL to meet lower limits than proposed for nitrogen oxides emissions.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ellen Porter of our Air Quality Branch in Denver at (303) 969-2617.

Sincerely,

Sam D. Hamilton
Regional Director

Enclosures

cc: Doug Neeley, Chief
Air and Radiation Branch
U.S. EPA, Region IV
100 Alabama St., SW
Atlanta, Georgia 30303

bcc:
FWS-REG. 4: AQC
CHAS: Refuge Manager
ARD-DEN: Ellen Porter
National Park Service - ARD
P.O. Box 25287
Denver, CO 80225

Technical Review of Prevention of Significant Deterioration Permit Application for Florida Power & Light Company's Manatee Power Plant Unit 3 Manatee County, Florida by Air Quality Branch, Fish and Wildlife Service – Denver March 18, 2002

Florida Power & Light (FPL) has submitted a Prevention of Significant Deterioration (PSD) permit application to construct and operate an 1150 MW combined cycle natural gas-fired combustion unit at its Manatee Power Plant in Manatee County, Florida. The new unit, Unit #3, would consist of four General Electric Frame 7FA combustion turbines and four heat recovery steam generators equipped with natural gas-fired duct burners. The facility is 115 km south of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service (FWS). This project will result in Prevention of Significant Deterioration (PSD) significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM10), volatile organic compounds (VOC), carbon monoxide (CO), and sulfuric acid mist (SAM). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	422
SO_2	191
PM10	229
VOC	106
CO	788
SAM	21.1

__Best Available Control Technology (BACT)__

When operating in combined cycle mode, NO_x emissions would be controlled by Selective Catalytic Reduction (SCR) to 2.5 parts per million (ppm). For approximately the first year of operation, FPL proposes to operate Unit #3 in a simple cycle mode with NO_x emissions controlled to 9-15 ppm by Dry Low-NO_x combustors. After the first year, FPL estimates that simple cycle operation would be limited to an aggregated total of 4000 hours per year. SO_2 and PM emissions would be controlled at all times by use of inherently clean natural gas with no oil back-up.

Combined Cycle Mode: Many state and local air pollution control agencies are currently engaged in reviewing a deluge of applications for permits for gas-fired, combined-cycle combustion turbines.[1] We support the use of gas-fired combined-cycle systems over simple-cycle systems for new power generation because of their higher efficiency and lower emissions and encourage permitting authorities to take full advantage of those low-emission capabilities.

[1] A simple cycle turbine system provides for only one pass of the combustion gases through a generator and then out of the exhaust stack. A combined cycle system is much more efficient (60% for combined cycle versus 38% for simple cycle) and uses the gases passing through the generator with supplementary firing to raise steam temperature and pressure for a steam turbine.

One of the requirements for issuing a PSD permit is that the applicant must demonstrate that it will use BACT. The Clean Air Act defines BACT as:

> "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant..."

On December 1, 1987, the EPA Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives designed to improve the effectiveness of the New Source Review programs within the confines of existing regulations and state implementation plans. Among these was the "top-down" method for determining BACT. In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent—or "top"—alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

To a great extent, BACT is set by precedent, by working from BACT determinations made elsewhere and applying that technology to a given situation on a case-by-case basis. As modern emission control technology advances, BACT is also expected to advance. While it may be difficult for an applicant to stay abreast of such improving technology, it is required to make a good faith effort. According to EPA's New Source Review Workshop Manual:

> Applicants are expected to identify all demonstrated and potentially applicable control technology alternatives. Information sources to consider include:
> - EPA's BACT/LAER Clearinghouse and Control Technology Center;
> - Best Available Control Technology Guideline - South Coast Air Quality Management District;
> - control technology vendors;
> - Federal/State/Local new source review permits and associated inspection/performance test reports;
> - environmental consultants;
> - technical journals, reports and newsletters (e.g., JAPCA and the McIvaine reports), air pollution control seminars; and
> - EPA's New Source Review (NSR) bulletin board.

FPL has proposed the use of SCR with a limit of 2.5 ppm NO_x. We agree that SCR is the best technology for this type of source, but we also believe that FPL must evaluate the feasibility of achieving a level of 2.0 ppm NO_x. For example, Washington State has recently proposed to permit two Siemens-Westinghouse combined cycle combustion turbines at 2.0 ppm when burning gas at the Sumas facility. On February 23, 2001, Washington State issued a PSD permit to Goldendale Energy, Inc. which included a BACT determination that this 249 MW combined cycle combustion turbine facility (with duct burners) would also meet a 3-hour NO_x limit of 2.0 ppm. There are numerous other similar sources that have been controlled to 2.0 ppm using SCR (See enclosed "Combined Cycle Turbines" table. Please note that many of these are BACT determinations.). A 2.0 ppm NO_x limit would reduce the gas-burning NO_x emissions from this source by 20% (84 tpy). The EPA New Source Review Workshop Manual states that "it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise."[2] Thus, the applicant must show why a 2.0 ppm limit is not technically feasible or why its control costs (per ton of reduction) are greater than those of its competitors. It would be helpful if FPL could explain any differences between the Manatee County installation and the plants shown on the enclosed list to justify the higher NO_x emission levels in Manatee County.

Ammonia Slip: We would also like to comment on the issue of ammonia slip. Ammonia slip from the SCR system occurs as the catalyst ages, so the ammonia slip guarantee refers to the end of the catalyst life cycle rather than a continuous emission. At a NO_x control conference in Dallas in 2000, vendors of SCR systems guaranteed various levels of slip; examples of these different guarantees from different vendors are:

- Not to exceed 2 ppm after 20,000 hours of catalyst operation.
- 2-5 ppm over the first four years of catalyst operation, increasing to 8-9 ppm after six years (10ppm guarantee)
- 1-2 ppm over the first four years of catalyst operation, increasing to 4-5 ppm after six years. (5 ppm guarantee)

Any concern that reducing NO_x limits would result in higher ammonia emissions is not supported in the application or by experience. (For example, the Goldendale permit mentioned above also contains an ammonia slip limit of 3.0 ppm.) NO_x and ammonia emissions are primarily related to catalyst size and condition—parameters that can be controlled by the vendor and user. We feel that the environmental benefits to visibility, acid- and nutrient-sensitive watersheds, and ozone-sensitive vegetation and people from the NO_x emissions reductions would outweigh the impact of the small amount of ammonia from a properly designed and operated SCR system.

Simple Cycle Mode: It appears that FPL is requesting a dual limit for NO_x emissions during simple cycle operation, 9 ppm during normal operation, with the higher 15ppm limit applying when the turbines are being pushed to very high output levels. While 9 ppm is acceptable as BACT for simple-cycle operation, 15 ppm is not. Not only is this approach unusual, but the degree of relaxation is unprecedented. Florida is the only state where we have seen this approach proposed, and, even then, the upper limit was only 10.5 ppm for a turbine that would normally run at 9 ppm. Instead of being allowed to push these turbines to the point where their emission control systems begin to fail, resulting in a 67% increase in emissions, FPL should consider installing additional, well-controlled capacity.

BACT Conclusions

While we agree that the use of SCR does constitute BACT for these units when operating in the combined-cycle mode, we disagree that FPL's proposed emission limits constitute BACT. We have pointed out that numerous facilities in other states have requested permits with a lower NO_x limit, while the Goldendale facility in Washington State was actually permitted at 2.0 ppm . Because the Goldendale

[2] New Source Review Workshop Manual, EPA, 1990, p. B.24

facility has a permit containing BACT limits lower than FPL's proposed 2.5 ppm limit, FPL must show why the cost to meet a 2.0 ppm limit at the Manatee County facility is significantly different from Goldendale (and others listed). We believe that, based on recent BACT determinations by other agencies, significant growth in power generation in Florida, and the potential for cumulative impacts on Chassahowitzka Wilderness, the FPL permit should establish a NO_x limit that is no higher than 2.0 ppm. We see no reason why new power generators in Florida should not be held to the same high environmental standards as their competitors in other states.

We disagree that FPL should be allowed to push these turbines in simple cycle mode to the point where their emission controls fail and emissions increase by 67%. Instead, FPL should consider installing additional, well-controlled capacity.

Class I Area Modeling Analyses

FPL used CALPUFF and CALMET (using MM4 data) to conduct the Class I analyses. The maximum impacts at the Class I area were below the significant impact levels for all increments. Therefore, no further analysis is needed. The maximum predicted impact on visibility, expressed as change in light extinction, was 0.64 percent, well below the recommended threshold of 5 percent. The maximum increases for nitrogen and sulfur deposition are 0.0016 and 0.0017 kilograms per hectare per year (kg/ha/yr), respectively. These values are well below the recommended deposition analysis thresholds of 0.01 kg/ha/yr for either nitrogen or sulfur.

The results of these analyses indicate that the project, by itself, should not adversely impact the air quality or air quality related values in Chassahowitzka Wilderness. However, as noted above, we recommend that FPL meet lower NO_x limits to reduce the potential for cumulative impacts (i.e., from many sources) to Chassahowitzka Wilderness.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Combined Cycle Turbines < 2.5ppm NOx

State	*Facility Name*	*Type*	*Total MW*	*Gas (ppm)*	*NOx Control*
CA	Magnolia Power	Westinghouse 501F	250	2	SCR
CA	Magnolia Power	GE Frame 7 FA	250	2	SCR
CA	Intergen-Ocotillo	GE Frame 7 FA		2	SCR
CA	Sunlaw Cogen	GE LM2500-M-2	28	2	Dry Low NOx
CA	Nueva Azalea		550	1	SCONOx
CA	Mountain View Power	GE Frame 7 FA	1991	2	SCR
CA	Calpine-Inland Empire Energy	GE Frame 7 FB	670	2	SCR
EPA	Teayawa		600	2	SCR
MA	ANP Blackstone	ABB GT-24		2	SCR
NV	Las Vegas Cogen	GE LM 6000 Aero PC	240	2	SCR
VA	Tractebel--Loudoun Energy Center	SW 501G	1400	2	SCR
WA	Goldendale Energy		249	2	SCR
WA	Sumas	Siemens-Westinghouse	669	2	SCR

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345
March 28, 2002

In Reply Refer To:
FWS/R4/RF/RS IV

RECEIVED

APR 04 2002

BUREAU OF AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the Prevention of Significant Deterioration Application for Florida Power and Light Company's (FPL) combined cycle project at the Manatee Power Plant in Manatee County, Florida. The facility is located 115 km south of Chassahowitzka Wilderness, a Class I air quality area administered by the Fish and Wildlife Service. The technical review comments from our Air Quality Branch are enclosed. Specifically, we recommend that your Department require FPL to meet lower limits than proposed for nitrogen oxides emissions.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ms. Ellen Porter at our Air Quality Branch in Denver, Colorado at (303) 969-2617.

Sincerely yours,

for Sam D. Hamilton
Regional Director

Enclosures

Technical Review of Prevention of Significant Deterioration Permit Application
for
Florida Power & Light Company's Manatee Power Plant Unit 3
Manatee County, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
March 18, 2002

Florida Power & Light (FPL) has submitted a Prevention of Significant Deterioration (PSD) permit application to construct and operate an 1150 MW combined cycle natural gas-fired combustion unit at its Manatee Power Plant in Manatee County, Florida. The new unit, Unit #3, would consist of four General Electric Frame 7FA combustion turbines and four heat recovery steam generators equipped with natural gas-fired duct burners. The facility is 115 km south of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service (FWS). This project will result in Prevention of Significant Deterioration (PSD) significant increases in emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM10), volatile organic compounds (VOC), carbon monoxide (CO), and sulfuric acid mist (SAM). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	422
SO_2	191
PM10	229
VOC	106
CO	788
SAM	21.1

Best Available Control Technology (BACT)

When operating in combined cycle mode, NO_x emissions would be controlled by Selective Catalytic Reduction (SCR) to 2.5 parts per million (ppm). For approximately the first year of operation, FPL proposes to operate Unit #3 in a simple cycle mode with NO_x emissions controlled to 9-15 ppm by Dry Low-NO_x combustors. After the first year, FPL estimates that simple cycle operation would be limited to an aggregated total of 4000 hours per year. SO_2 and PM emissions would be controlled at all times by use of inherently clean natural gas with no oil back-up.

Combined Cycle Mode: Many state and local air pollution control agencies are currently engaged in reviewing a deluge of applications for permits for gas-fired, combined-cycle combustion turbines.[1] We support the use of gas-fired combined-cycle systems over simple-cycle systems for new power generation because of their higher efficiency and lower emissions and encourage permitting authorities to take full advantage of those low-emission capabilities.

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[1] A simple cycle turbine system provides for only one pass of the combustion gases through a generator and then out of the exhaust stack. A combined cycle system is much more efficient (60% for combined cycle versus 38% for simple cycle) and uses the gases passing through the generator with supplementary firing to raise steam temperature and pressure for a steam turbine.

One of the requirements for issuing a PSD permit is that the applicant must demonstrate that it will use BACT. The Clean Air Act defines BACT as:

> "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant..."

On December 1, 1987, the EPA Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives designed to improve the effectiveness of the New Source Review programs within the confines of existing regulations and state implementation plans. Among these was the "top-down" method for determining BACT. In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent—or "top"—alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

To a great extent, BACT is set by precedent, by working from BACT determinations made elsewhere and applying that technology to a given situation on a case-by-case basis. As modern emission control technology advances, BACT is also expected to advance. While it may be difficult for an applicant to stay abreast of such improving technology, it is required to make a good faith effort. According to EPA's New Source Review Workshop Manual:

> Applicants are expected to identify all demonstrated and potentially applicable control technology alternatives. Information sources to consider include:
> - EPA's BACT/LAER Clearinghouse and Control Technology Center;
> - Best Available Control Technology Guideline - South Coast Air Quality Management District;
> - control technology vendors;
> - Federal/State/Local new source review permits and associated inspection/performance test reports;
> - environmental consultants;
> - technical journals, reports and newsletters (e.g., JAPCA and the McIvaine reports), air pollution control seminars; and
> - EPA's New Source Review (NSR) bulletin board.

FPL has proposed the use of SCR with a limit of 2.5 ppm NO_x. We agree that SCR is the best technology for this type of source, but we also believe that FPL must evaluate the feasibility of achieving a level of 2.0 ppm NO_x. For example, Washington State has recently proposed to permit two Siemens-Westinghouse combined cycle combustion turbines at 2.0 ppm when burning gas at the Sumas facility. On February 23, 2001, Washington State issued a PSD permit to Goldendale Energy, Inc. which included a BACT determination that this 249 MW combined cycle combustion turbine facility (with duct burners) would also meet a 3-hour NO_x limit of 2.0 ppm. There are numerous other similar sources that have been controlled to 2.0 ppm using SCR (See enclosed "Combined Cycle Turbines" table. Please note that many of these are BACT determinations.). A 2.0 ppm NO_x limit would reduce the gas-burning NO_x emissions from this source by 20% (84 tpy). The EPA New Source Review Workshop Manual states that "it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise."[2] Thus, the applicant must show why a 2.0 ppm limit is not technically feasible or why its control costs (per ton of reduction) are greater than those of its competitors. It would be helpful if FPL could explain any differences between the Manatee County installation and the plants shown on the enclosed list to justify the higher NO_x emission levels in Manatee County.

Ammonia Slip: We would also like to comment on the issue of ammonia slip. Ammonia slip from the SCR system occurs as the catalyst ages, so the ammonia slip guarantee refers to the end of the catalyst life cycle rather than a continuous emission. At a NO_x control conference in Dallas in 2000, vendors of SCR systems guaranteed various levels of slip; examples of these different guarantees from different vendors are:

- Not to exceed 2 ppm after 20,000 hours of catalyst operation.
- 2-5 ppm over the first four years of catalyst operation, increasing to 8-9 ppm after six years (10ppm guarantee)
- 1-2 ppm over the first four years of catalyst operation, increasing to 4-5 ppm after six years. (5 ppm guarantee)

Any concern that reducing NO_x limits would result in higher ammonia emissions is not supported in the application or by experience. (For example, the Goldendale permit mentioned above also contains an ammonia slip limit of 3.0 ppm.) NO_x and ammonia emissions are primarily related to catalyst size and condition—parameters that can be controlled by the vendor and user. We feel that the environmental benefits to visibility, acid- and nutrient-sensitive watersheds, and ozone-sensitive vegetation and people from the NO_x emissions reductions would outweigh the impact of the small amount of ammonia from a properly designed and operated SCR system.

Simple Cycle Mode: It appears that FPL is requesting a dual limit for NO_x emissions during simple cycle operation, 9 ppm during normal operation, with the higher 15ppm limit applying when the turbines are being pushed to very high output levels. While 9 ppm is acceptable as BACT for simple-cycle operation, 15 ppm is not. Not only is this approach unusual, but the degree of relaxation is unprecedented. Florida is the only state where we have seen this approach proposed, and, even then, the upper limit was only 10.5 ppm for a turbine that would normally run at 9 ppm. Instead of being allowed to push these turbines to the point where their emission control systems begin to fail, resulting in a 67% increase in emissions, FPL should consider installing additional, well-controlled capacity.

BACT Conclusions

While we agree that the use of SCR does constitute BACT for these units when operating in the combined-cycle mode, we disagree that FPL's proposed emission limits constitute BACT. We have pointed out that numerous facilities in other states have requested permits with a lower NO_x limit, while the Goldendale facility in Washington State was actually permitted at 2.0 ppm . Because the Goldendale

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[2] New Source Review Workshop Manual, EPA, 1990, p. B.24

facility has a permit containing BACT limits lower than FPL's proposed 2.5 ppm limit, FPL must show why the cost to meet a 2.0 ppm limit at the Manatee County facility is significantly different from Goldendale (and others listed). We believe that, based on recent BACT determinations by other agencies, significant growth in power generation in Florida, and the potential for cumulative impacts on Chassahowitzka Wilderness, the FPL permit should establish a NO_x limit that is no higher than 2.0 ppm. We see no reason why new power generators in Florida should not be held to the same high environmental standards as their competitors in other states.

We disagree that FPL should be allowed to push these turbines in simple cycle mode to the point where their emission controls fail and emissions increase by 67%. Instead, FPL should consider installing additional, well-controlled capacity.

Class I Area Modeling Analyses

FPL used CALPUFF and CALMET (using MM4 data) to conduct the Class I analyses. The maximum impacts at the Class I area were below the significant impact levels for all increments. Therefore, no further analysis is needed. The maximum predicted impact on visibility, expressed as change in light extinction, was 0.64 percent, well below the recommended threshold of 5 percent. The maximum increases for nitrogen and sulfur deposition are 0.0016 and 0.0017 kilograms per hectare per year (kg/ha/yr), respectively. These values are well below the recommended deposition analysis thresholds of 0.01 kg/ha/yr for either nitrogen or sulfur.

The results of these analyses indicate that the project, by itself, should not adversely impact the air quality or air quality related values in Chassahowitzka Wilderness. However, as noted above, we recommend that FPL meet lower NO_x limits to reduce the potential for cumulative impacts (i.e., from many sources) to Chassahowitzka Wilderness.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Combined Cycle Turbines < 2.5ppm NOx

State	Facility Name	Type	Total MW	Gas (ppm)	NOx Control
CA	Magnolia Power	Westinghouse 501F	250	2	SCR
CA	Magnolia Power	GE Frame 7 FA	250	2	SCR
CA	Intergen-Ocotillo	GE Frame 7 FA		2	SCR
CA	Sunlaw Cogen	GE LM2500-M-2	28	2	Dry Low NOx
CA	Nueva Azalea		550	1	SCONOx
CA	Mountain View Power	GE Frame 7 FA	1991	2	SCR
CA	Calpine-Inland Empire Energy	GE Frame 7 FB	670	2	SCR
EPA	Teayawa		600	2	SCR
MA	ANP Blackstone	ABB GT-24		2	SCR
NV	Las Vegas Cogen	GE LM 6000 Aero PC	240	2	SCR
VA	Tractebel–Loudoun Energy Center	SW 501G	1400	2	SCR
WA	Goldendale Energy		249	2	SCR
WA	Sumas	Siemens-Westinghouse	669	2	SCR

Department of Environmental Protection
Southwest District
Office of the Director

Facsimile Transmittal Sheet

DATE: 2/19/02

TO: Howard Rhodes
Buck Oven
Allen Hubbard

TELEPHONE:

FAX NUMBER: SC 291-7250
SC 292-6979
SC 287-3618

FROM:

☒ Deborah A. Getzoff, Director
☐ James Cleary, Assistant Director
☐ Meritt Mitchell, External Affairs Manager
☐ Mike Zavosky, External Affairs Coordinator
☐ Sandra Lynch, Administrative Assistant

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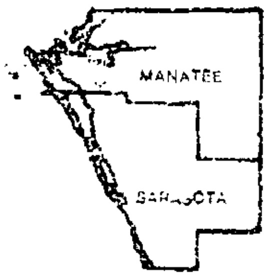
Total Pages: 2

RE: Manatee Power Plant

☐ Urgent ☐ Please Review ☐ Please Comment ☒ For Your Information ☐ Confirmation Requested

Comments:

Al Linero
from Howard 2/22



MANASOTA-88

A Project for Environmental Quality 1968-2088

Deborak Getzoff - Director
Department of Environmental Protection
3804 Coconut Palm Drive
Tampa, Florida 33619

February 13, 2002

Re: Manatee Power Plant

Dear Ms. Getzoff,

Please advise ManaSota-88 of proposed agency action or agency action on the Manatee Power Plant located in Parrish, Florida. Facility ID # 0810010 at the following address:

Glenn Compton
Chairman - ManaSota-88
419 Rubens Drive
Nokomis, Florida 34275

Thank you,

Glenn Compton

Chairman, ManaSota-88

RECEIVED
FEB 15 2002
SOUTHWEST DISTRICT

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