STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

DEP File No. 1110099-002-AC (PSD-305)
Midway Energy Center, Units 1 – 3
St. Lucie County

Enclosed is the Final Permit Number PSD-FL-305 to construct three 170-megawatt dual-fuel combustion turbines with inlet chillers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Midway Energy Center to be located in St. Lucie County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 2/14/01 to the person(s) listed:

Ben Jacoby, MDC*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, DEP SED
Chair, St. Lucie County BCC
Blair Burgess, P.E., ENSR

Clerk Stamp

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

Charlotte J. Hayes 2/14/01
(Clerk) (Date)

FINAL DETERMINATION
File No. 1110099-002-AC (PSD-FL-305)
MIDWAY DEVELOPMENT COMPANY, L.L.C.
510 MW SIMPLE CYCLE FACILITY

The Department distributed a Public Notice package on December 18, 2000 for the project to construct a nominal 510-megawatt (MW) natural gas and fuel oil-fired simple cycle facility to be known as the Midway Energy Center near Port St. Lucie and Fort Pierce in St. Lucie County. The project consists of three nominal 170 MW General Electric 7FA combustion turbine-electrical generators, three 150-foot stacks, a 2.5 million gallon fuel oil storage tank, a 0.6 million gallon fuel oil "day" tank, and other ancillary equipment.

The Public Notice of Intent to Issue was published on December 21, 2000 in The Tribune. Written comments were received from EPA Region IV and the applicant, Midway Development Company, L.L.C (Midway - an affiliate of Enron North America).

The written comments (in italics) are addressed below. Each is followed by the Department's response.

EPA Comments

1. *<u>Section III. Emission Units Specific Conditions, Applicable Standards and Regulations, 6.</u>: 40 C.F.R. Subpart Dc is an applicable requirement for the gas heater. In 40 C.F.R. § 60.41c, a steam generating unit is defined as a device that combusts any fuel and produces steam or heat water or any other heats transfer medium. Heat transfer medium is defined as any material that is used to transfer heat from one point to another point. The natural gas heaters meet the definition of steam generating unit; therefore, they are an affected facility as defined in 40 C.F.R. § 60.40c(a). Also, pursuant to 40 C.F.R. § 60.48c(g), the permittee must record the amount of each fuel combusted each day. Please include this applicable requirement in the permit.*

   The Department agrees with EPA and the requirements of 40 CFR Subpart Dc will be included for the heaters.

2. *<u>Section III. Emission Units Specific Conditions, General Operation Requirements, 13. Maximum allowable hours</u>: To limit the potential to emit, the operation limitations (hours of operation per year) should be expressed in terms of 12 consecutive months, rather than calendar year. This 12-month consecutive limit prevents the enforcing agency from having to wait for long periods of time to establish a continuing violation before initiating enforcement.*

   The Department agrees with EPA and the hours per year will be changed to read 12 consecutive months.

3. *<u>Section III. Emission Units Specific Conditions, Excess Emissions, 25.</u> The Florida Department of Environmental Protection should include definitions of what constitutes "startup" and "shutdown" as referenced in this section.*

The Department does not allow extended operation at low loads, during which such emissions typically occur. The facility must also employ good operating practices to allow excess emissions.

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

The Department will progressively implement EPA's comments for future projects as we get emissions data from facilities required to demonstrate compliance by CEMS. As drafted, the permit includes Specific Conditions (22, 23, 24, 44, 45) related to excess emissions during startup, shutdown, and valid, documented malfunctions. See condition 43 of Section III of this permit for provisions that relate to excluding periods of CEM system data recorded for NO_X and CO for episodes of startup, shutdown and malfunction. However, these periods are recorded and reported as excess emissions as stated in conditions 24 and 45.

Gas turbine <u>startup</u> is the commencement of operation of a gas turbine which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. <u>Shutdown</u> is the process of bringing a gas turbine off line and ending fuel combustion.

Midway's comments:

4. *<u>Section II. Administrative Requirements, Specific Condition (SC) 8 (page 5 of 15):</u> At our request, the permit expiration date was extended. However, we believe it was the Department's intent to revise the language as follows: "The expiration date is June 30, 2003. Physical construction shall be complete by December 31, 200<u>2</u>~~3~~."*

   The typographical error was corrected to read 2002.

5. *<u>Section III. General Operation Requirements, SC 13 and 14 (pages 7 and 8 of 15)</u>: As suggested in a separate letter to the Department, dated January 23, 2001, it's requested that the language in SC 13 and 14 be revised. The suggested language below provides the Department with reasonable assurance that the intent is for natural gas to be the primary fuel for this proposed project:*

   <u>Specific Condition 13 - Maximum allowable hours</u>: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any calendar year, as <u>may be adjusted in condition 14 below, based on oil fired run hours</u>~~. The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any calendar year~~. No single combustion turbine shall operate more than 5,000 hours in a single year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

   <u>Specific Condition 14 - Fuel oil usage</u>: ~~The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period. The Department may waive this requirement during the first 24 months of operation based on natural gas availability.~~

In order to encourage the maximum use of natural gas as fuel, during any calendar year the three stationary gas turbines shall operate on fuel oil for no more than an average of 1000 hours per installed unit. Furthermore, during any calendar year, the maximum allowable operating hours referenced in condition 13 above shall be reduced by two hours for each oil fired hour in excess of an average of 500 per installed unit. For example, if the three stationary gas turbines operate on fuel oil in any calendar year for an average of 550 hours per installed unit, the total maximum allowable operating hours shall be decreased to 3,400.

[Rule 62-212.400, F.A.C. (BACT)]

Note: In a phone conversation with Midway representatives on February 8, the company further proposed to reduce to 250 hours the level at which the "2 for 1" trigger would kick in. Therefore if the three stationary gas turbines operate on fuel oil in any calendar year for the permitted average of 1000 hours per installed unit, the total maximum allowable operating hours shall be decreased to 2,000 hours.

The Department met with Midway representatives on January 17 to discuss these matters. The Department emphasized that a major part of the Best Available Control Technology (BACT) is the use of natural gas. The company argued that there is not yet enough firm supply of natural gas to insure that in a given year or in a given 12-month period they can commit to firing more gas than fuel oil.

Apparently Florida Gas Transmission (FGT) Phase IV and V (and proposed Phase VI) Expansions extend to points North and West of the planned Midway site. Therefore Midway will rely on interruptible supply from the existing FGT capacity in Southeast Florida if it chooses to purchase gas from FGT. This situation could change as FGT considers possible future capacity expansion in Southeast Florida.

The approved Gulfstream Pipeline will extend from Manatee County and includes segments to St. Lucie and Belle Glade. This presents another opportunity for Midway to obtain gas. Additionally, Enron (parent of Midway) has announced a possible project involving construction of a liquefied natural gas (LNG) handling terminal in the Bahamas together with a pipeline to the Southeast Florida Coast.

If the company actually uses more fuel oil than gas, then a better effort needs to be made to reduce emissions while firing fuel oil. For example, nitrogen oxides (NO_X) emissions while firing fuel oil are 42 parts per million by volume dry (ppmvd), whereas emissions while firing natural gas are only 9 ppmvd.

Midway and other companies argue that the NO_X guarantee while burning fuel oil is still 42 ppmvd from General Electric. They are not willing to commit to further wet injection to reduce emissions to less than the guaranteed values. However, it is clear that lower emissions are feasible with wet injection than indicated by the guarantees. For example, initial compliance tests on a GE 7FA simple cycle combustion turbine at the JEA Kennedy Plant indicated NO_X emissions of 30 ppmvd @15% O_2. The added costs in terms of reduced lifetime and increased maintenance are unknown.

There is already a requirement (within Section III, Condition 19) for Midway to develop a NO_X reduction plan when the hours of oil firing reach 500 hours per year per unit. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised.

The Department concludes that Midway's proposed draft permit revision, the fuel oil use hammers, and the various gas supply options will encourage Enron to make sure more gas becomes available for its planned Midway Project as well as for its other projects planned in Broward County. The permit will be modified accordingly.

It is noted that Midway's potential to emit will be significantly reduced because maximum oil use will reduce total hours of operation by an average of 1500 per unit. For example, potential NO_X emissions from the facility will be reduced from roughly 735 tons per year to approximately 600 tons per year.

6. *Section III. SC 17 (page 8 of 15): The permit language states that "The permittee shall provide manufacturer's emissions vs. load diagrams for the DLN and wet injection systems prior to their installation." Past requests of the manufacturer for these types of diagrams have been unsuccessful. Typically, the manufacturer will provide emission estimates at various load points corresponding to various inlet temperature cases. These emission values, that are the basis for this permit, were previously provided in the permit application. It's requested that the word "diagrams" in the above sentence be replaced with the word "estimates".*

   The Department has regularly obtained such diagrams from operators throughout the State. The Department will to change the language from "prior to installation" to "upon installation and completion of testing" for submittal of the required diagrams.

7. *Section III. SC 19 (page 9 of 15): The language concerning fuel oil firing should be revised as follows: "In addition, NO_X emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd at 15% O_2 to be demonstrated by initial stack test."*

   The Department revised this condition to include the word initial as suggested. Reference to Method 20 will be added for consistency with the previous condition.

8. *Section III. SC 20 (page 9 of 15): The CO emission limit for fuel oil presented in the permit application was based on 20 ppmvd. At a temperature of 30 °F, this corresponds to 69.6 lb/hour, not 46 lb/hour, as shown in the draft permit. The 20 ppm concentration is based on 100% load. Concentrations of CO are estimated to be as high as 22 ppm at 75% load factor and 30 ppm at 50% load factor. The peak emission estimate is 78.3 lb/hour at 50% load and 91°F. Based on these factors we request that the permit limit for oil firing be expressed as follows: "The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 31 lb/hr (gas) and neither 20 ppmvd nor 70 lb/hour (fuel oil) to be demonstrated by stack tests at full load operation."*

   This condition will be revised as suggested. The Department notes, however, that initial testing of General Electric 7FA combustion turbines indicates emissions in the range of 0.5 to 2 ppm whether burning natural gas or fuel oil. Such results have been observed at TECO Polk Power, JEA and City of Tallahassee facilities.

The Department will monitor long-term performance on CO at some of the combined cycle units that have continuous emissions monitors. This may result in lower emission limits issued to applicants for combustion turbine projects in the future.

9. <u>Section III. SC 27 (page 10 of 15)</u>: *The last sentence should be revised as follows: "...periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. ~~18 and~~ 19."*

   This condition was revised to read 19.

10. <u>Section III. SC 29 (page 11 of 15):</u> *The permit language indicates that emission testing by EPA Reference Methods 9 and 10 (for visible emissions and CO emissions, respectively) are to be conducted both initially and annually for both fuels. In the past, the Department has issued permits (e.g., Hines Energy Complex) with language that requires that annual testing be done on fuel oil (the backup fuel) only if a threshold number of operating hours on oil is exceeded (e.g., 400 hr/CT) during a rolling 12-month period. This is because it's a financial hardship to require operation on the more expensive fuel. It's requested that the conditions be revised to include annual testing for VE and CO emissions on oil, only if a CT exceeds 400 hours of operation in a 12-month rolling period.*

    The Department does not consider it to be a financial hardship for Midway to test for CO and VE while firing fuel oil and it is not clear that fuel oil is exclusively just the back-up fuel. In the case of Hines, the allowable hours on fuel oil operation are much lower than the hours on natural gas operation. At Midway, the fuel oil firing can be very significant compared with natural gas. Additionally, permitted CO emissions are much higher than for the fuel oil case than for the natural gas case.

11. <u>Section III. SC 33 (page 11 of 15)</u>: *It's requested that the same language be included here regarding the annual testing requirement for visible emissions while firing oil.*

    See discussion in 10 above.

12. <u>Section III. SC 36 (page 12 of 15)</u>: *The second sentence should be revised as follows: "...corrected for the average <u>inlet</u> ~~ambient~~ air temperature during the test...".*

    The Department will revise this condition as suggested.

13. <u>Section III. SC 45 (page 13 of 15):</u> *The last sentence states that "these excess emissions periods shall be reported as required in Specific Conditions 24 and 46." The reference to SC 24 appears to be incorrect, as it refers to the limitation for visible emissions.*

    The reference to Specific Condition 24 in Specific Condition 45 will be revised to read Specific Condition 27.

14. <u>Section III. SC 46 (page 14 of 15):</u> *Although the language is intended to instruct on the procedure to determine compliance with the 24-hour rolling average, the second sentence refers to a separate compliance determination being conducted at the "end of each operating day". This language is appropriate in the context of a 24-hour*

block average, but should be deleted from SC 46, which is addressing rolling averages.

This condition was revised to read 24-hour block average.

15. <u>Section III. SC 47 (page 14 of 15):</u> *The Specific Conditions referenced in the last sentence of this condition (20, 21 and 29) all appear to be incorrect. The conditions need to be cross-referenced correctly or deleted. Also, the appropriate DEP office to notify would be the Southeast District, not the South District.*

    This condition was revised to read reference to Specific Conditions 18, 19 and 24. The District office was changed as suggested.

16. <u>Section III. SC 49 (page 14 of 15):</u> *Some of the text appears to be missing. There doesn't appear to be any schedule for testing of sulfur or nitrogen in natural gas in the bulleted items. In fact, the bulleted items appear to be related to compliance with the Acid Rain requirements of Parts 72 and 75, not with Part 60 Subpart GG compliance (which is what requires a Custom Fuel Schedule).*

17. <u>Section III. SC 50 (page 15 of 15):</u> *It's requested that the requirement to conduct sampling and analysis for fuel bound nitrogen content be deleted. Typically, the requirement to monitor water-to-fuel ratio, combined with the requirement to analyze for fuel bound nitrogen content, provides a surrogate for NO_X compliance. As recognized by the Department in the language of SC 48, the NO_X CEMS are to be used in lieu of the water/fuel monitoring system for reporting excess emissions. Given that NO_X CEMS will be used for compliance, the monitoring of the fuel bound nitrogen content serves no useful purpose, and should not be required.*

    The Department replaced the above conditions with the new condition (SC 49) below. The requirements of the 40CFR60, Subpart GG will be attached as Appendix GG. This new Appendix includes all the Department requirements regarding this Subpart GG.

New Specific Condition 49:

<u>Fuel Sulfur Records</u>: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

Compliance with the fuel sulfur limit for *natural gas* shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

Compliance with the *fuel oil* sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

18. *<u>Particulate Limits:</u> The Department has determined that measurement of front-half catch by EPA Method 5 is sufficient to demonstrate the BACT emission limit for PM_{10}.*

EPA Method 5 measuring the front-half catch only is now specified for compliance with the PM_{10} standard. Because the back-half catch is excluded, the emission limits are reduced from 18 to 10 and from 34 to 17 pounds per hour while firing natural gas and fuel oil respectively. These values are equal to previous BACT determination for GE 7FA simple cycle units.

CONCLUSION

The Department will issue the permit with the changes noted above.

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Midway Development Company
1400 Smith Street
Houston, Texas 77002-7631

Permit No.	PSD-FL-305
File No.	1110099-002-AC
SIC No.	4911
Expires:	June 30, 2003

Authorized Representative:

Ben Jacoby

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers; one 2.5-million gallon fuel oil storage tank; one 0.6 million gallon fuel oil storage tank; a natural gas heater; and three 80-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located Northwest of the intersection of I-95 and W. Midway Road near Port St. Lucie and Ft. Pierce in unincorporated St. Lucie County. UTM coordinates are Zone 17; 556.7 km E; 3028.5 km N.

STATEMENT OF BASIS:

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

Attached Appendices and Tables made a part of this permit:

Appendix GG	40 CFR 60 NSPS, Subpart GG
Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers, three 80-foot stacks, one 2.5-million gallon fuel oil storage tank, one 0.6-million gallon storage tank, a gas heater and ancillary equipment. Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emission Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
004	Fuel Storage	One 2.5-Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	One 0.6 Million Gallon Fuel Oil Storage Tank
006	Fuel Heating	One 13 million Btu per hour Natural Gas heater

REGULATORY CLASSIFICATION

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

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 12/21/00 Notice of Intent published in The Tribune, St Lucie County
- 12/18/00 Distributed Intent to Issue Permit
- 11/09/00 Received Application

RELEVANT DOCUMENTS:

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

- Application received on November 9, 2000
- Letters from Enron North America dated December 5, 2000; January 23, and February 2, 2001.
- Letter from U.S. EPA Region IV dated January 19, 2001
- Department's Intent to Issue and Public Notice Package dated December 15, 2000
- Updated application received from Enron North America on January 17, 2001
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the *Permitting Authority*: Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the *Compliance Authority*: DEP Southeast District office, 400 North Congress Avenue W, West Palm, Florida, 33401 and phone number 561/681-6755, fax 561-681-6755. Copies shall be sent to the DEP Port St. Lucie Branch office, 1801 SE Hillsmoore Dr, C 204, Port St. Lucie, Florida 34952 and phone number 561/398-2806, fax 561/398-2815.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. PSD Approval to Construct Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].
7. BACT Determination Revision: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will

also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing (e.g. conversion to combined-cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

8. Completion of Construction: The permit expiration date is June 30, 2003. Physical construction shall be complete by December 31, 2002. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

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

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

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

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southeast District and a copy to the DEP's Port St. Lucie Branch offices by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

13. Quarterly Reports: Semiannual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (2000 version), shall be submitted to the DEP's Southeast District and a copy to the DEP's Port St. Lucie Branch offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

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

3. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

4. ARMS Emission Unit 004, Fuel Storage, consisting of one 2.5 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Unit 005, Fuel Storage, consisting of one 0.6 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. ARMS Emission Unit 006, Fuel Heating, consisting of one 13 million Btu per hour natural gas heater to heat natural gas used by the combustion turbines. This unit shall comply with applicable requirements of 40CFR60, Subpart Dc.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in these units.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
{Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

8. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 30 °F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,700 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,900 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing.
[Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Southeast District as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.
[Rule 62-4.130, F.A.C.]

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

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any consecutive 12-month period. This

amount shall be reduced by two hours for each fuel oil-fired hour in excess of an average of 250 per installed unit. No single combustion turbine shall operate more than 5,000 hours in any consecutive 12-month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any consecutive 12-month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

Control Technology

15. Dry Low NO_X (DLN-2.6) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

16. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems upon completion of initial testing. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology.

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	11/17 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC (not PSD)	As Above	2.8 ppmvd @15% O_2 (Gas or Fuel Oil)
CO	As Above	9 ppmvd @15% O_2 (Gas) 20 ppmvd @15% O_2 (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	2 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and limited Fuel Oil usage	9 ppmvd @15% O_2 (Gas) 42 ppmvd @15% O_2 (Fuel Oil)

19. Nitrogen Oxides (NO_X) Emissions:
    - *While firing Natural Gas*: The emission rate of NO_X in the exhaust gas shall not exceed 9 ppmvd @15% O_2 on a 24-hr block average as measured by the continuous emission monitoring system (CEMS) in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 62 pounds per hour nor 9 ppmvd @15% O_2 to be demonstrated by the initial stack test using EPA Method 20. [Rule 62-212.400, F.A.C.]
    - *While firing Fuel Oil*: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd @15% O_2 on the basis of a 3-hr block average as measured by the CEMS in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd @15% O_2 to be demonstrated by initial stack test using EPA Method 20. [Rule 62-212.400, F.A.C.]
    - *NO_X Reduction Plan*: The permittee shall develop a NO_X reduction plan when the hours of oil firing reach 500 hours per year per unit. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without adversely affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. [Rule 62-212.400, F.A.C., BACT Determination].
20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 9 ppmvd @15% O_2 nor 31 lb/hr (gas) and neither 20 ppmvd @15% O_2 nor 70 lb/hr (fuel oil) at 30^0F to be demonstrated by stack tests. [Rule 62-212.400, F.A.C.]
21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas shall exceed neither 2.8 ppmvd @15% O_2 nor 6 lb/hr (gas or fuel oil) to be demonstrated by initial stack tests. [Non-applicability of Rule 62-212.400, F.A.C.]
22. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Emissions: SO_2 and SAM emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or No. 2 distillate fuel oil with a maximum 0.05 percent sulfur for 1000 hours per year per unit. Emissions of SO_2 shall exceed neither 11 lb/hr (natural gas) nor 104 lb/hr (fuel oil). Emissions of sulfuric acid mist shall exceed neither 2 lb/hr (natural gas) nor 16 lb/hr (fuel oil). These emissions shall be measured by applicable compliance methods described below.
    [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]
23. Particulate Matter (PM/PM_{10}): PM/PM_{10} emissions shall exceed neither 10 lb/hr (gas) nor 17 lb/hr (fuel oil) to be demonstrated by initial stack tests. [Rule 62-212.400, F.A.C.]

24. Visible Emissions: Visible Emissions shall not exceed 10 percent opacity to be demonstrated by visual observation tests.
[Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. Excess Emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

26. Excess Emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southeast District within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Following the NSPS format, 40 CFR 60.7 Subpart A, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 19.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (2000 version)].

COMPLIANCE DETERMINATION

28. Compliance Test Schedules: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit and as required by the *Compliance Authority*. [Rules 62-204.800 and 62-4.070(3) F.A.C.]

- *Initial*: Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors.
- *Annual*: Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated.
- *Prior Permit Renewal*: All tests shall be conducted within 12 months prior permit renewal.

29. Reference Methods: The following reference methods as described in 40 CFR 60, Appendix A (2000 version), and adopted by reference in Chapter 62-204.800, F.A.C. shall be used to demonstrate compliance with the allowable emissions limits. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
    - EPA Reference Method 5, "Determination of Particulate Matter Emissions from Stationary Sources" (I).
    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for NO_X compliance with 40CFR60 Subpart GG.
    - EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements.
    - EPA Reference Method 25A, "Determination of Total Hydrocarbon Concentrations." Correction for methane by EPA Method 18 is allowed. Initial test only.
30. Compliance with CO emission limits: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75
31. Compliance with the VOC emission limits: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.
32. Compliance with the NOx emission limits: Compliance with the NO_X emissions limits shall be determined by stack tests and a CEMS as specified in specific conditions 30, 45 and 46.
33. Compliance with the PM/PM_{10} and VE emission limits: Initial and annual tests are required for visible emissions (VE). Initial stack test is required for PM/PM_{10}. Tests for PM and VE shall be conducted concurrently.
34. Continuous compliance with the PM/PM_{10}, SO_2 and sulfuric acid mist emission limits: Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and the restricted use of No. 2 distillate fuel oil (or superior grade) are the methods for determining continuous compliance for PM/PM_{10}, SO_2 and sulfuric acid mist.
35. Test Method for Natural Gas and Fuel Oil Sulfur Content: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM D 2880-71 (or equivalent) for sulfur

content of *liquid fuel* and ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of *gaseous fuel* shall be utilized in accordance with the EPA-approved custom fuel monitoring schedules. Natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Refer to Appendix GG.

36. Testing procedures: Initial testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for compressor inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

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

38. Test Notification: The DEP's Southeast District and the DEP's Port St. Lucie Branch District offices shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

39. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

40. Test Results: Compliance test results indicating the results of the required compliance tests shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie Branch District offices no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

42. Notifications: All notifications and reports required by 40 CFR60, Subpart A shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie Branch District offices.

MONITORING REQUIREMENTS

43. Continuous Monitoring System Procedures: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the NO_X emissions from each CT. Each device shall properly function prior to the initial performance tests and comply with the applicable monitoring system requirements of 40 CFR 75.62. Upon request from DEP, the CEMS emission rates for NO_X on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 62-4.130, F.A.C and 40CFR75]

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

45. Continuous Monitoring System Operation: The continuous monitoring systems (CEMS) for NO_X shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Valid hourly emission rates shall not include periods of startup, shutdown, fuel switching, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as require in Specific Conditions 27 and 46.
[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 60.13, 40 CFR 75].

46. Continuous Compliance with the NO_X Emission Limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on a 24-hour block average (gas) and 3-hr block average (oil). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of 24-hr (gas) and 3-hr (oil) valid hourly

measurements from the previous operating hours. A valid hourly emission rate shall be calculated for each hour (during which fuel is fired) in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction unless prohibited by Rule 62-210.700, F.A.C.
[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

47. CEMS for Reporting Excess Emissions: The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (2000 version). Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40 CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15 % oxygen) are above the permit limits listed in Specific Conditions 18 and 19 shall be reported to the DEP Southeast District office as required in Specific Condition 24.

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

49. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

50. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

Midway Energy Center
PSD-FL-305 and 1110099-002-AC
St. Lucie County, Florida

BACKGROUND

The applicant, Midway development Company, L.L.C. (Midway, an affiliate of Enron North America) proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Midway Energy Center, East of Arcadia in unincorporated St. Lucie County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 80-foot stacks. Midway proposes to operate these units up to 3,500 hours per year per unit of which 1000 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated December 15, 2000, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on November 9, 2000 (revised December 5) and included a proposed BACT proposal prepared by the applicant's consultant, ENSR.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	9 ppmvd @ 15% O_2 (gas)[1] 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (1000 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	9 ppmvd (gas, baseload) 30 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	2 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

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

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by Midway is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the Midway Energy Center.

A National Emission Standard for Hazardous Air Pollutants (NESHAP) under development exists for stationary gas turbines. However this facility will not be subject to the NESHAP or to a requirement for a case-by-case determination of maximum achievable control technology because HAP emissions will be less than 10 TPY.

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple cycle turbines. Two (Carson and McClellan) were permitted in ozone non-attainment areas and two (Lakeland and PREPA) were permitted as continuous duty projects. The proposed Midway Energy Center is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 11/00. 1000 hrs on oil
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 10/00. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 2/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Tenaska Heard, GA	960	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
RockGen Cristiana, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous DLN = Dry Low NO_X Combustion FO = Fuel Oil GE = General Electric
SC = Simple Cycle SCR = Selective Catalytic Reduction NG = Natural Gas WH = Westinghouse
INT = Intermittent HSCR = Hot SCR WI = Water or Steam Injection ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	2.8 lb/hr – NG 7.5 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly

with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

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

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

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

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Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Midway project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 1000 hours per year (per CT).

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

NO_X Control Techniques

Wet Injection

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

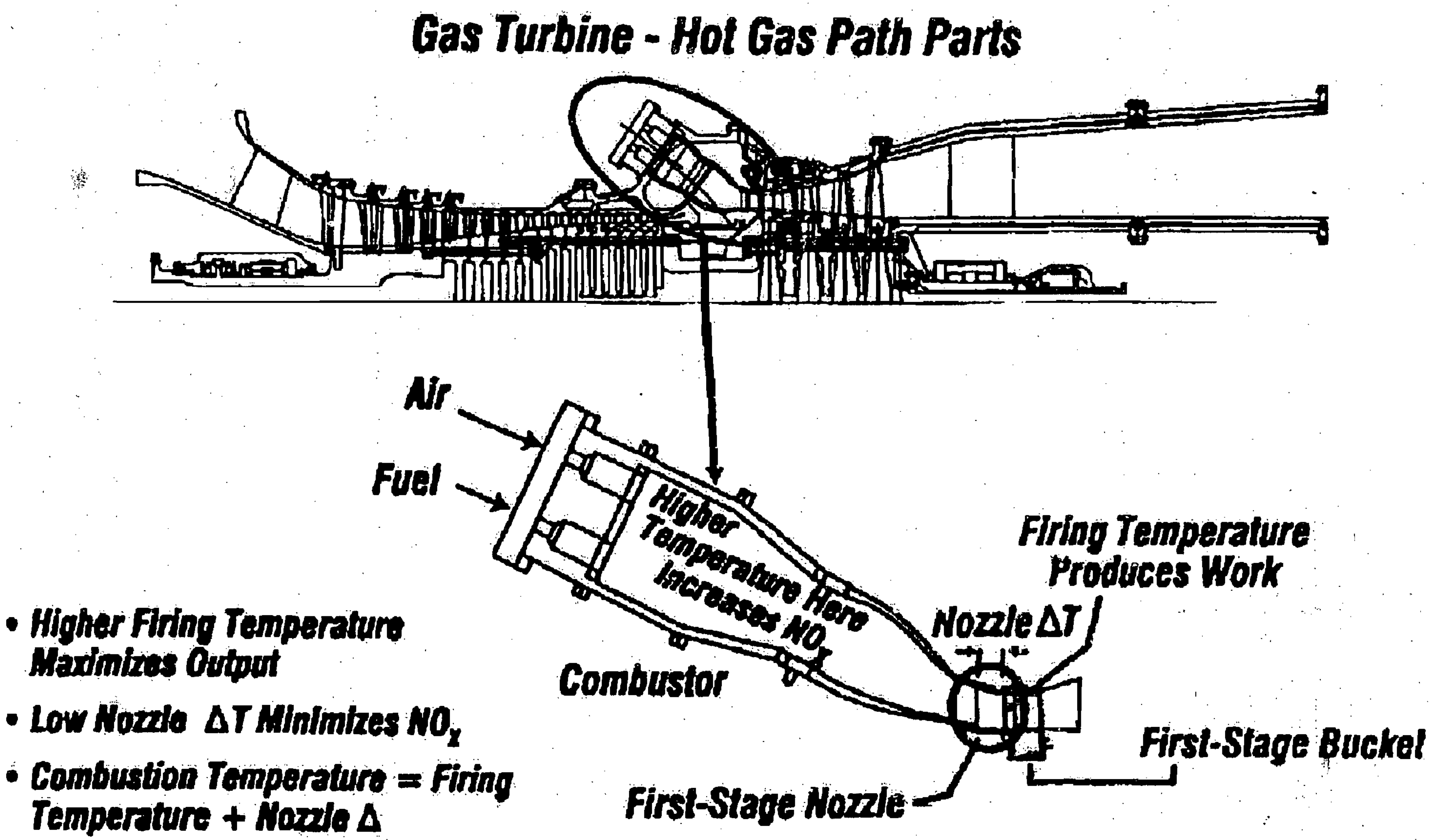

Figure 1 – Relation Between Flame Temperature and Firing Temperature

Combustion Controls

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

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X.

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd while burning natural gas. The results are all superior to the emission characteristics given in Figure 3.

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

Emissions characteristics by wet injection NO_X control while firing oil are shown in Figure 4 for the DLN-2.0, a predecessor of the DLN2-6. Operation on fuel oil is not in the premixed mode. Tests at the JEA[2] Kennedy Plant indicated that 30 ppmvd is achievable on a short-term basis.

Specialized premixed DLN burners for fuel oil operation were installed in a project in Israel[3] where water is scarce, but the Department has no information on the results. Mitsubishi (who also make a 501F) is developing a dual-fuel premixed DLN. Optimization of premix fuel-air nozzle and performance was verified in high-pressure combustion tests. Commissioning tests on gas and oil burning were completed at an undesignated site.[4] The details are not available in English.

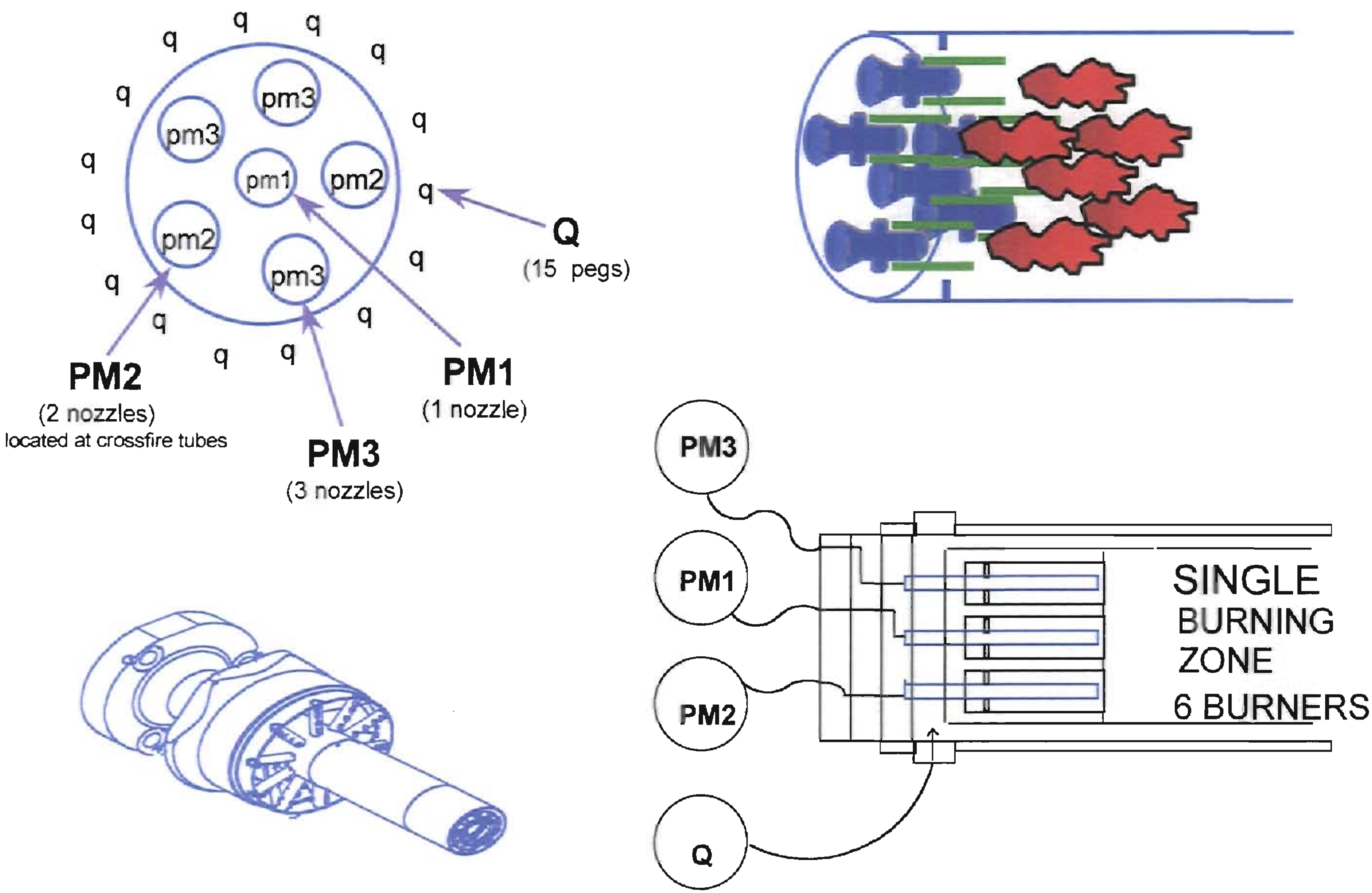

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

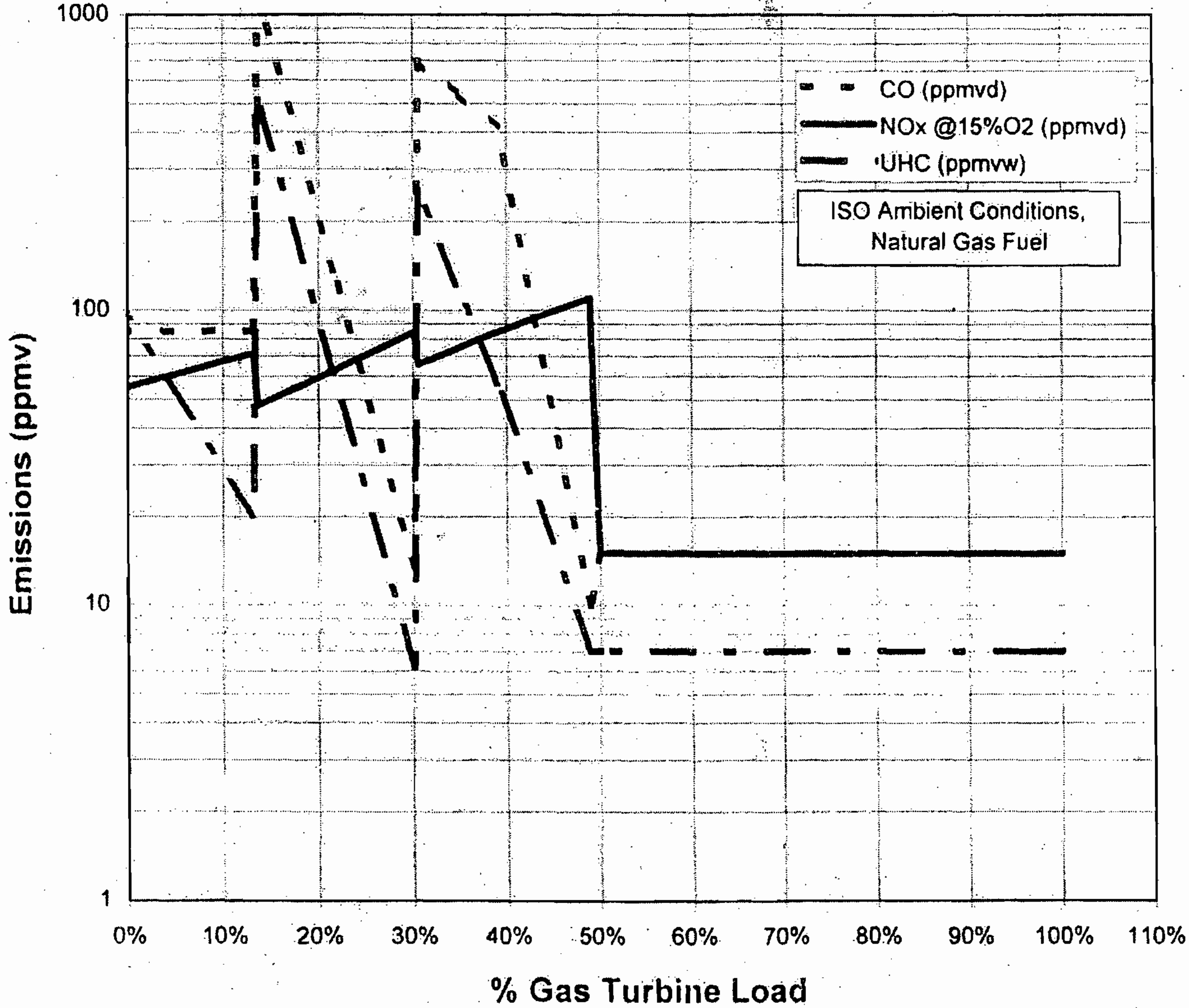

Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

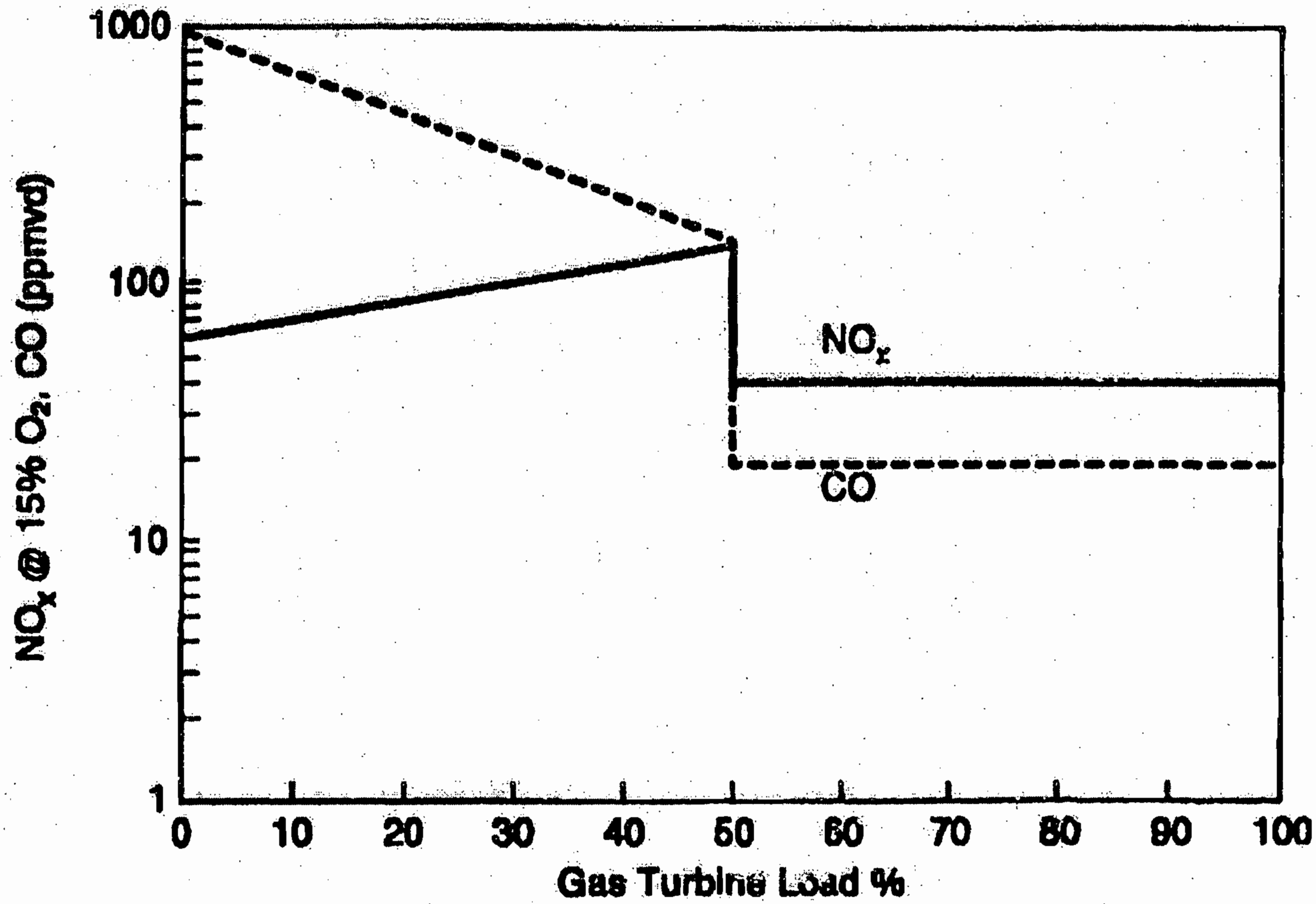

Figure 4 – Emissions Performance for DLN-2 Combustors
Firing Fuel Oil in Dual Fuel GE 7FA Turbine

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 5 from an EPRI report.[5] Basically developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 5.

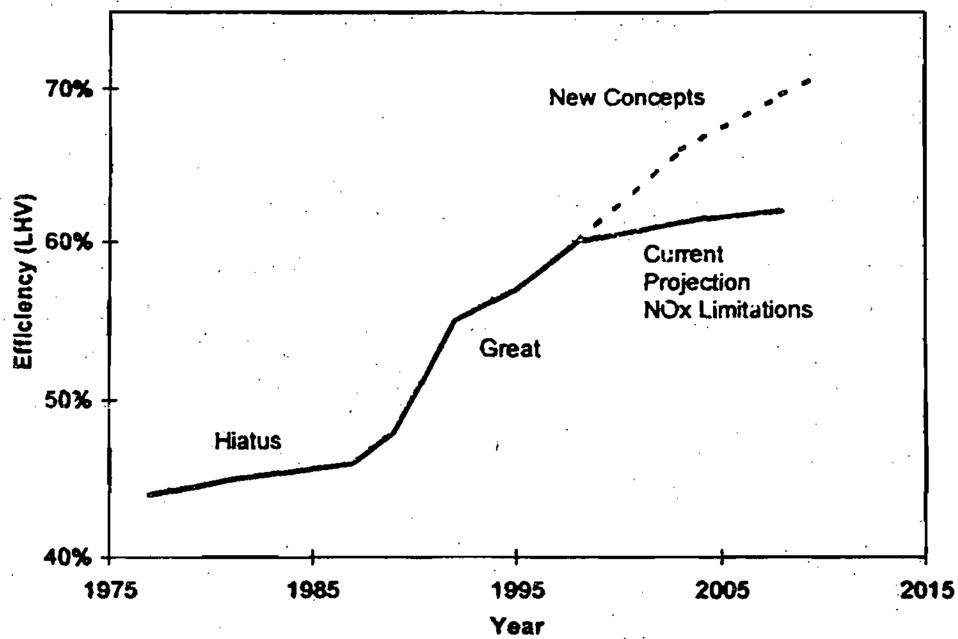

Figure 5 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by Midway. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air-cooling.

Catalytic Combustion: XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[6] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

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

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[7] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma which documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

Recently, Catalytica and GE announced that the XONON™ combustion system has been specified as the *preferred* emissions control system with GE 7FA turbines that have been ordered for Enron's proposed 750 MW Pastoria Energy Facility.[8] The project will enter commercial operation by the summer of 2001. However actual installation of XONON™ is doubtful.

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

Selective Catalytic Combustion

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

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

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998.

Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 (Paynes Creek) project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority,[9] FPC, TECO, and Competitive Power Ventures will install SCR on combined cycle projects to achieve 3.5 ppmvd. Limits as low as 2 ppmvd NO_X have been specified using SCR on combined cycle F Class projects in various parts of the country.

Selective Non-Catalytic Combustion

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

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

$SCONO_X$™

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

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

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

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X.[13] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmv.

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[14]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

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

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

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 190 TPY of SO_2 and 29 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grain of sulfur per 100 standard cubic feet (gr S/100scf). This value is well below the "default" maximum value of 20 gr. S/100 scf, but high enough to require a BACT determination.

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 1000 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 119 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[15]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 9 and 30 ppmvd for gas and oil respectively at baseload proposed in Midway's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Midway for this project are 1.4 ppmvw for gas and fuel oil firing at baseload. These limits are sufficient to keep annual emissions of VOC below the 40 TPY threshold and a BACT determination is not required. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[16]

BACKGROUND ON PROPOSED GAS TURBINE

Midway plans to install three nominal 170 MW General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

Typically, companies obtain a guarantee from GE to achieve 9 ppmvd NO_X during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation. With the frequent start-ups and shutdowns of the units, some applicants are concerned about the ability to maintain the low NO_X values for long periods of time. As a result, some of them agreed to a "new and clean" limit of 9 ppmvd but requested a continuing BACT limit of 10.5 ppmvd.

As detailed in the table above, the Department has issued quite a number of permits for simple cycle GE 7FA requiring achievement of 9-10.5 ppmvd without the requirement of any additional control equipment. The ones with limits of 9 ppmvd are allowed to operate for as many as 1000 hours per year on back-up fuel oil whereas the ones permitted at 10.5 ppmvd are allowed only 750 hours per year of fuel oil. A smaller GE unit known as the 7EA can routinely achieve 9 ppmvd NO_X or lower based on numerous installations in Florida and elsewhere. The 7EA has a lower flame temperature, compression ratio, and power rating (85 versus 170 MW) than the 7FA.

The ability to meet a NO_X emission limit of 9 ppmvd by DLN technology involves a substantial efficiency and energy penalty as previously discussed. For example, the 7FA is characterized by a 15.5:1 compression ratio, a 2400 °F firing temperature, 56 percent efficiency, and produces 263 MW in combined cycle. On the other hand, GE offers a more efficient F-Class model known as the 7FB, but guarantees a NO_X limit of 25 ppmvd by DLN.

The 7FB is characterized by an 18.5:1 compression ratio, a 2500 °F firing temperature, 57.3 percent efficiency, and produces 280 MW in combined cycle. The clear implication is that the

power penalty to reduce NO_X from 25 to 9 ppmvd by DLN technology alone is on the order of 20 MW for a combined cycle (roughly 13 MW on a simple cycle unit).[17]

Another example of this point is the ABB GT24. It is characterized by a 30:1 compression ratio and 58 percent efficiency in combined cycle. The unit is guaranteed to meet 25 ppmvd of NO_X. The simple cycle version is rated at 183 MW compared to 170 for the GE7FA.

It is not surprising that some compromises were made by ABB, which resulted in greater power and efficiency but slowed progress toward single-digit NO_X emissions. According to ABB, "rather than just concentrating on ever lower NO_X levels, ABB has chosen a total solution that limits pollutants and at the same time increases energy efficiency."[18] A lower compression, lower efficiency version of the ABB GT24 might be capable of 15 ppmvd NO_X or less by DLN technology.

The results during the "new and clean" test of the GE PG7241 at the Polk Power Station (discussed above) are nothing short of spectacular in comparison with the permitted emission limits. It is doubtful that these values can be maintained indefinitely. However, there is good reason to believe that performance will continue to be better than the permitted emission limits. For reference, the values while burning oil were equally good in comparison to the permitted limits for CO and VOC, whereas the NO_X emissions were very close to the permitted value of 42 ppmvd @15% O_2. Visible emissions were 0 percent opacity when firing natural gas or fuel oil.

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

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Midway project assuming full load. Values for NO_X and CO are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions Nos. 18 through 23.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 10/17 lb/hr – Gas/Fuel Oil (Front-half)
CO	As Above	9 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	As Above	2 grain of sulfur per 100 ft^3 gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	9 ppmvd – Gas 42 ppmvd – F.O. for 1000 of 3,500 hrs

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are Hot SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- Hot SCR is not commonly required as BACT on simple cycle combustion turbines. Although it was required on the fuel oil-fired PREPA project (to achieve 10 ppmvd), the requirement has been removed from the permit. It is noted that the specification of the fuel oil was 0.15 percent sulfur. This does not imply that hot SCR it is not technically feasible for intermittent duty simple cycle combustion turbines firing natural gas with 0.05 percent sulfur fuel oil as back-up fuel.
- Hot SCR is required at the simple cycle continuous duty Lakeland McIntosh Unit 5 project if the Westinghouse 501 G unit fails to achieve 9 ppmvd while firing natural gas. Hot SCR was considered cost-effective because the unit will operate continuously and the expected NO_X reduction is from 25 to 9 ppmvd).
- The levelized costs of NO_X removal by Hot SCR for the Midway Project were estimated by ENSR at $20,700 per ton assuming 3,500 hours of dual-fuel operation. The estimates are based on emissions controlled to 4.5 and 7.5 ppmvd @15% O_2 NO_X while burning gas and fuel oil respectively and 5 ppmvd @15% O_2 ammonia slip.
- The levelized costs of NO_X removal by Hot SCR for the DeSoto project were estimated by Golder at $11,350 per ton assuming 3,390 hours of operation on natural gas and a reduction to 3.6 ppmvd on gas and 17 ppmvd on fuel oil. The estimates are based on an ammonia slip of 9 ppmvd for gas and 12 ppmvd for oil.
- The Department does not accept the precise hot SCR cost calculations presented by Midway and considers them on the high end. The costs calculated by Golder for the DeSoto Project are probably more accurate. With the actual performance of the GE 7FA at TECO Polk Power Station with no add-on control (5-8 ppmvd @15%O_2), it is easy to see that hot SCR would not be cost-effective. Hot SCR is rejected as BACT.
- The Department will limit operation of the three units to 3,500 hours per year per unit. No single unit may operate more than 5,000 hours per year to insure that the conclusion regarding cost-effectiveness remains applicable.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out

the possibility of SCONO$_X$. XONON is available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO$_X$. This value is equal to that required at the Lakeland continuous duty combustion turbine, which has an alternative hot SCR requirement.
- Typical permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them.
- The 9 ppmvd limit at Oleander, Vandolah, Shady Hills, DeSoto, Virginia Power, and Midway while firing natural gas is the lowest known BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42-ppmvd limit for limited fuel oil firing is typical.
- The gas-based NO$_X$ emission limit of 9 ppmvd will be difficult to maintain over short term averaging times. That is the main reason why some operators cannot provide reasonable assurance they can meet such a low limit by DLN. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into an emissions limit with a long-term averaging time for continuous duty. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion.
- The Department issued permits for the TEC Polk Power, JEA Brandy Branch, and Reliant Osceola Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander, Vandolah, Shady Hills, and DeSoto.
- The proposed BACT limit of 9 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO$_X$ emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO$_X$ is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO$_X$ emissions for units permitted to fire substantial amounts of fuel oil.[20]
- Based on test results at the JEA Kennedy Plant, it is possible that the NO$_X$ emissions while firing oil from may be reduced from 42 to 30 ppmvd. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO$_X$ emission rates while firing oil have been achieved.

- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- The fuel oil-based NO_X emissions limit of 42 ppmvd can be maintained over a short-term averaging period by varying the amount of water injected. The Department has determined that a 3-hour averaging time is appropriate.
- The Department's overall BACT determination is equivalent to approximately 0.4 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- The applicant estimates VOC emissions of 1.4 ppmvd while firing gas and 1.4 ppmvd while burning fuel oil. The Department will set the limits at 2.8 ppmvd because at this concentration, the project will still not trigger PSD or a requirement for a BACT determination.
- The Department will set CO limits achievable by good combustion at full load as 9 ppmvd @15% O_2 (gas) and 20 ppmvd (oil). These values are in the lower range of values from permitted or proposed simple cycle units. These limits are equal to or lower those proposed by the Department for the Oleander, Vandolah, DeSoto, Reliant, JEA Brandy Branch, and TEC Polk Power projects.
- Midway estimated levelized costs for CO catalyst control at $31,800 per ton. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- Golder evaluated the use of oxidation catalyst for the DeSoto project with 90 percent control efficiency. Golder estimated levelized costs for CO catalyst control at $7,500 per ton.
- The cost of CO control by oxidation catalyst is probably closer to the Golder estimate based on reducing *permitted* CO emissions. However in view of the performance of GE 7FA units without add-on control (~1 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- The Department will not set a continuous CO limit reflecting the "new and clean test" because GE will not guarantee it. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.
- There is no benefit in penalizing the applicant or with a lower limit at this time just because the performance at another site was far better than guaranteed or expected.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limits for PM_{10} will be set at 10 pounds per hour during gas operation and 17 pounds per hour while operating on fuel oil. These values are based on front-half catch.

- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power, DeSoto Power, Vandolah, Shady Hills and quite a number of combined cycle projects.

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Carbon Monoxide	Annual Method 10
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (gas - 24-hr block average) (oil – 3-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed. During gas operation, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C.
SO_2 and SAM	Custom Fuel Monitoring Schedule- Refer to Appendix GG

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:

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

Date: 2/14/01

Approved By:

Howard L. Rhodes
Howard L. Rhodes, Director
Division of Air Resources Management

Date: 2/14/01

REFERENCES

[1] Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TECO Polk Power Station." September 2000.

[2] Summary. "Initial Compliance Testing at the JEA Kennedy Plant." January 2001.

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[9] Permit. Florida DEP. KUA Cane Island Unit 3. File PSD-FL-254. November 1999.

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[14] News Release. ABB Alstom Power, Environmental Segment. ABB Alstom Power to Supply Groundbreaking SCONOX™ Technology. December 1, 1999.

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[18] ABB Combined Cycle Website. Combustion Turbines. Environmental Burner. www.abbccpp.com.

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

[20] Letter. Linero, A. A., FDEP to Forry, J. and Chalfin, J. General Electric. NO_X emissions control while firing fuel oil in Simple Cycle Units. October 12, 1999.

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

11. Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

<u>Department requirement</u>: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

<u>Department requirement</u>: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

<u>Department requirement</u>: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide*. Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)(Pr/Po)^{0.5} e^{19(Ho-0.00633)} (288°K/Ta)^{1.53}$$

where:

NOx	=	emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.
Noxo	=	observed NOx concentration, ppm by volume.
Pr	=	reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.
Po	=	observed combustor inlet absolute pressure at test, mm Hg.
Ho	=	observed humidity of ambient air, g H2O/g air.
e	=	transcendental constant, 2.718.
Ta	=	ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20

following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

<u>Department requirement</u>: The permit species sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Memorandum

Florida Department of Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy

FROM: Al Linero 2/1~
Teresa Heron

DATE: February 12 , 2000

SUBJECT: Midway Energy Center
Three 170 MW Combustion Turbines
DEP File No. 1110099-002-AC (PSD-FL-305)

Attached is the final package for construction of three dual-fuel, intermittent duty, simple cycle, 170 MW GE 7FA combustion turbines with inlet air chillers, two fuel oil storage tanks, a gas heater, and ancillary equipment at the planned (Enron) Midway Energy Center in St. Lucie County.

NO_X emissions from the combustion turbine will be controlled to 9 ppmvd Dry Low NO_X (DLN-2.6) technology while firing natural gas. The facility may operate 3,500 hours per year per unit. Use of fuel oil (during which emissions of 42 ppmvd are allowed) will be permitted up to 1000 hours per year per unit.

Conditions in the draft permit required Midway to burn more gas than oil. Midway did not petition the permit, but asked relief from this condition based on claims that the gas supply is actually uncertain during the first few years of operation.

To insure there is still a big incentive to fire gas when available and to encourage further development of firm supplies in the area, Midway proposed a condition that will result in cutbacks in total hours of operation after Midway fires 250 hours per year per unit. For example, if Midway actually burns fuel oil for 1000 hours each unit can only operate for 2000 hours.

The permit will also require Midway to examine the possibility of NO_X reductions (from 42 ppmvd) while firing fuel oil. We are aware that JEA achieved 30 ppmvd while firing fuel oil during the initial compliance test at their GE 7FA unit at the Kennedy Plant.

We are reviewing almost two identical applications from Enron in Broward County. I expect similar permits unless any Class I Area issues are raised by the National Park Service.

We recommend your approval of the attached Intent to Issue.

AAL/al

Attachments

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

RECEIVED
JAN 17 2001
BUREAU OF AIR REGULATION

January 16, 2001

Mr. Al Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Midway Development Company, LLC
Revised Permit Application for Midway Energy Center

Dear Mr. Linero:

On behalf of Midway Development Company, LLC, enclosed for your records are four (4) copies of a revised air permit application for the Midway Energy Center electric generating plant in St. Lucie County, Florida. This revised application addresses the reduction in hours of oil use from 1500 to 1000 and a change in the requested emission limit for NOx from 12 ppm to 9 ppm when firing natural gas.

Our consultant ENSR had previously sent you an electronic copy of this revised application.

If you have any questions, please don't hesitate to call me at (713) 853-3161.

Sincerely,
Enron North America

David A. Kellermeyer

David A. Kellermeyer
Director

Enclosures

cc: Mr. Lennon Anderson, DEP West Palm Beach

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

February 2, 2001

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FEB 05 2001
BUREAU OF AIR REGULATION

Mr. Al Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Re: DEP File No. 1110099-002-AC (PSD-FL-305)
Midway Energy Center, St. Lucie County
Comments on Draft PSD Permit

Dear Mr. Linero:

This letter serves to provide comments on the draft permit for the above-referenced facility. The Department issued the Draft Permit, Technical Evaluation and Preliminary Determination on December 15, 2000. Comments are provided below, in the order in which they occur in the draft permit.

1. Section II. Administrative Requirements, Specific Condition (SC) 8 (page 5 of 15): At our request, the permit expiration date was extended. However, we believe it was the Department's intent to revise the language as follows: "The expiration date is June 30, 2003. Physical construction shall be complete by December 31, 2002~~3~~."

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lb/hour, not 46 lb/hour, as shown in the draft permit. The 20 ppm concentration is based on 100% load. Concentrations of CO are estimated to be as high as 22 ppm at 75% load factor and 30 ppm at 50% load factor. The peak emission estimate is 78.3 lb/hour at 50% load and 91 F. Based on these factors we request that the permit limit for oil firing be expressed as follows: "The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 31 lb/hr (gas) and neither 20 ppmvd nor 70 lb/hour (fuel oil) to be demonstrated by stack *tests at full load operation.*"

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If you should have any questions concerning these comments, please do not hesitate to contact me at (713) 853-3161.

Sincerely,

David A. Kellermeyer

David A. Kellermeyer
Authorized Agent

Attachment

cc: Greg Krause
Raimund Grube
Ben Jacoby
Scott Osbourn, ENSR

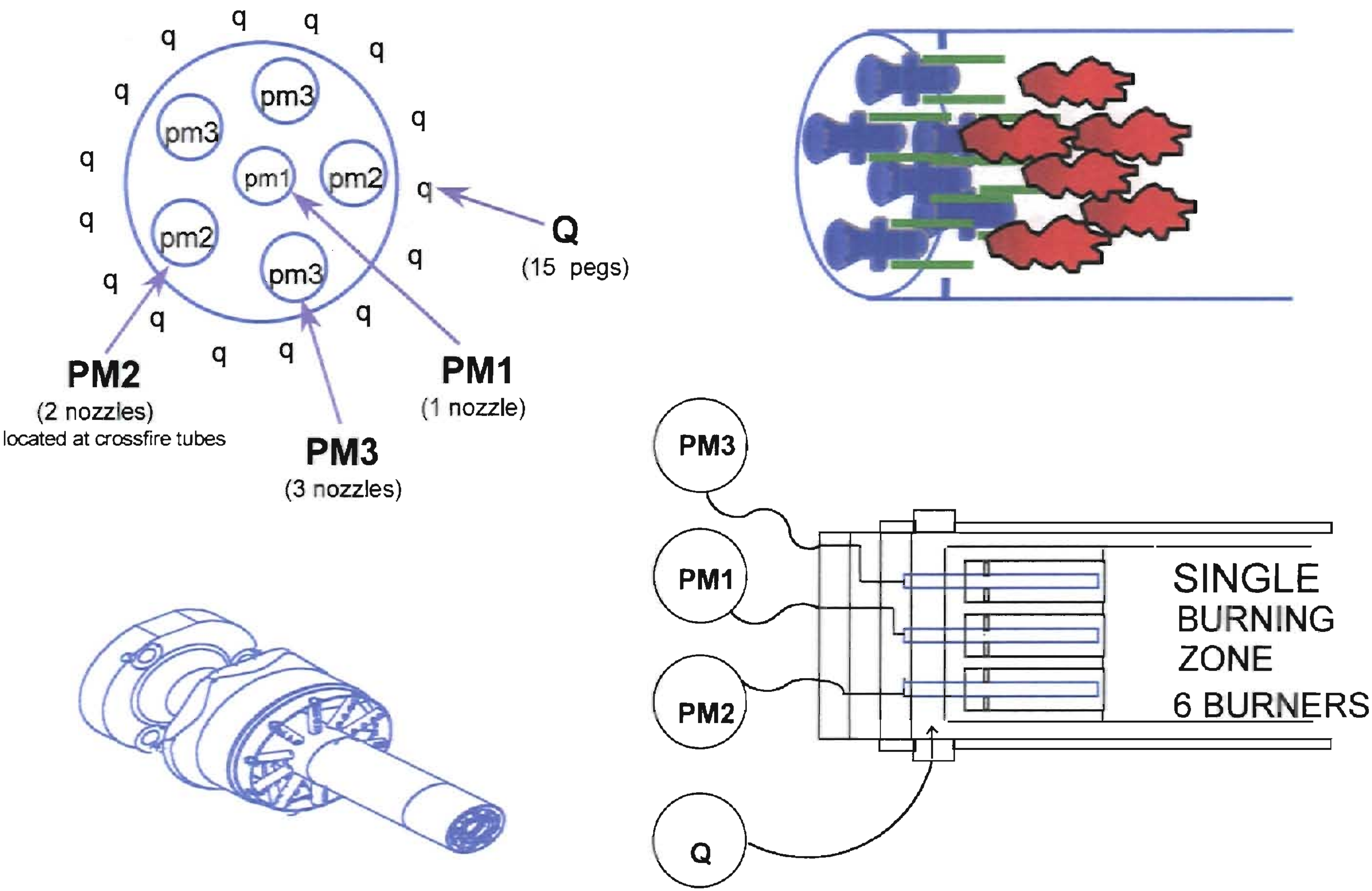


Figure 2 - DLN2.6 Fuel Nozzle Arrangement

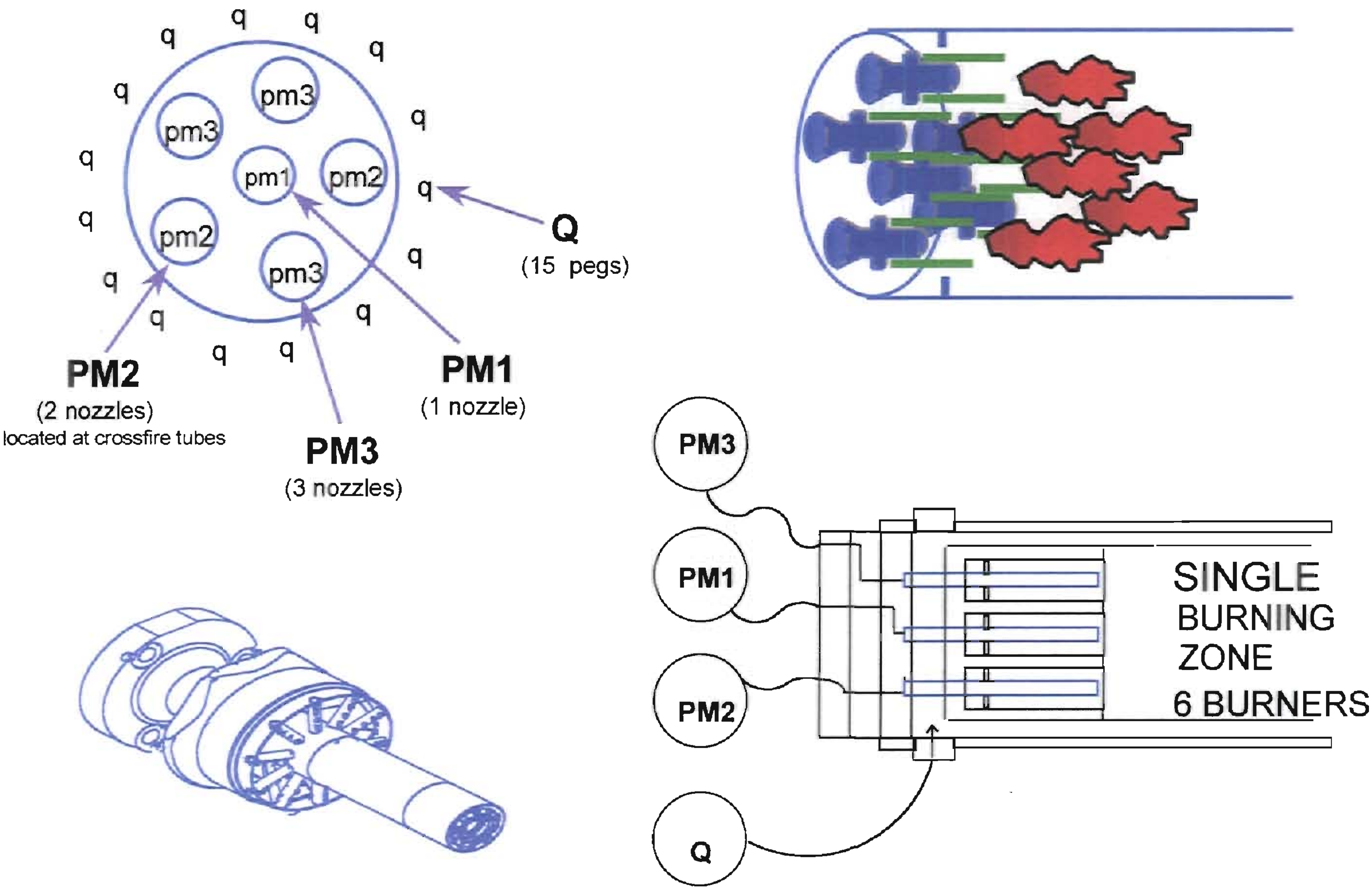


Figure 2 - DLN2.6 Fuel Nozzle Arrangement

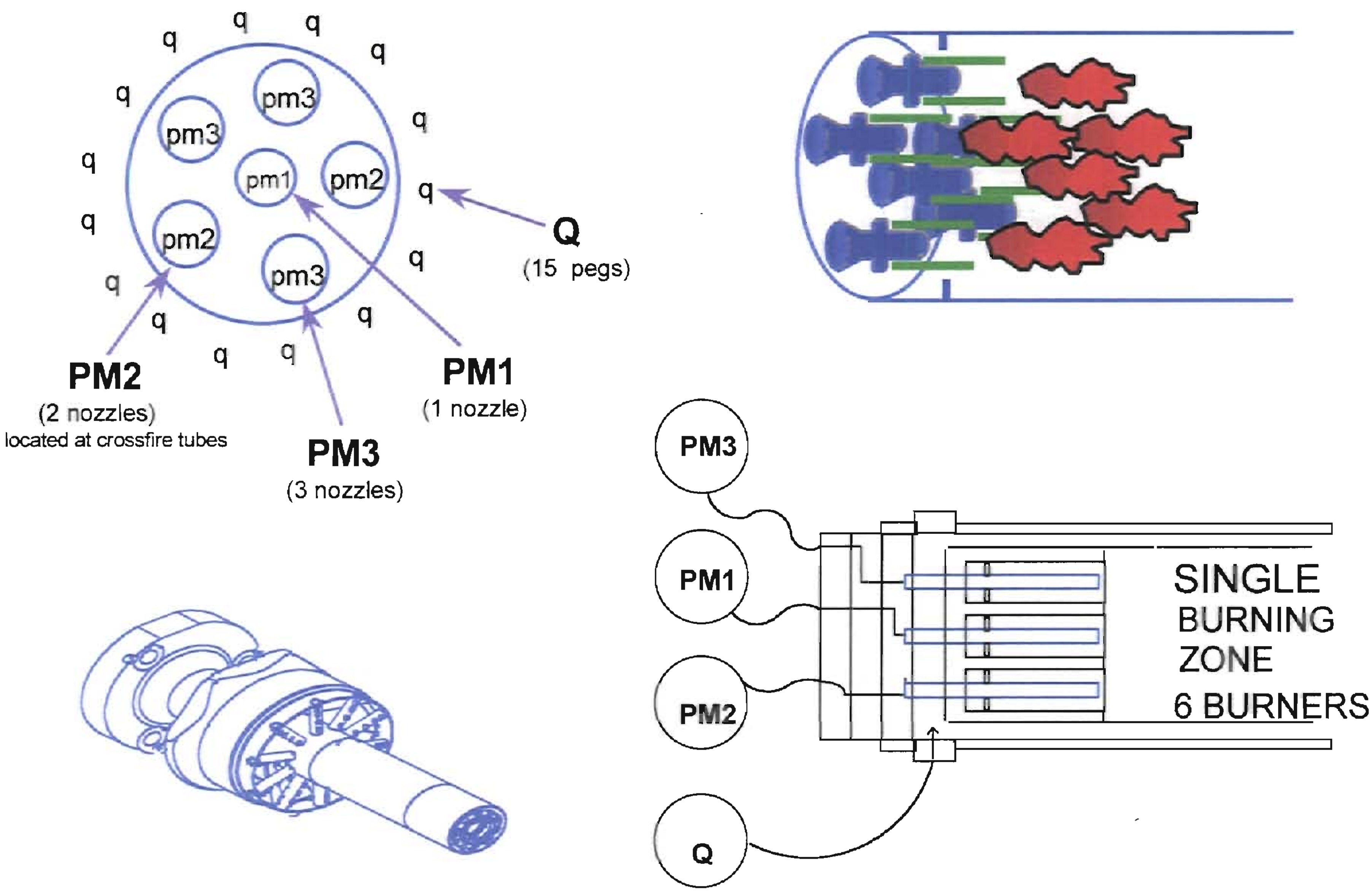


Figure 2 - DLN2.6 Fuel Nozzle Arrangement

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Ben Jacoby, Director
Midway Development Co., L.L.C.
1400 Smith St.
Houston, Texas 77002-7631

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) H. WYATT

B. Date of Delivery 2-20-01

C. Signature x H. Wyatt ☐ Agent ☐ Addressee

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

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

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

2. Article Number (*Copy from service label*)
7099 3400 0000 1449 3799

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

7099 3400 0000 1449 3799

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

Article Sent To:
Mr. Ben Jacoby, Director

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

Name (*Please Print Clearly*) (*to be completed by mailer*)
Mr. Ben Jacoby
Street, Apt. No.; or PO Box No.
1400 Smith St.
City, State, ZIP+4
Houston, Texas 77002-7631

PS Form 3800, July 1999 See Reverse for Instructions

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

DEP File No. 1110099-002-AC (PSD-305)
Midway Energy Center, Units 1 – 3
St. Lucie County

Enclosed is the Final Permit Number PSD-FL-305 to construct three 170-megawatt dual-fuel combustion turbines with inlet chillers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Midway Energy Center to be located in St. Lucie County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 2/14/01 to the person(s) listed:

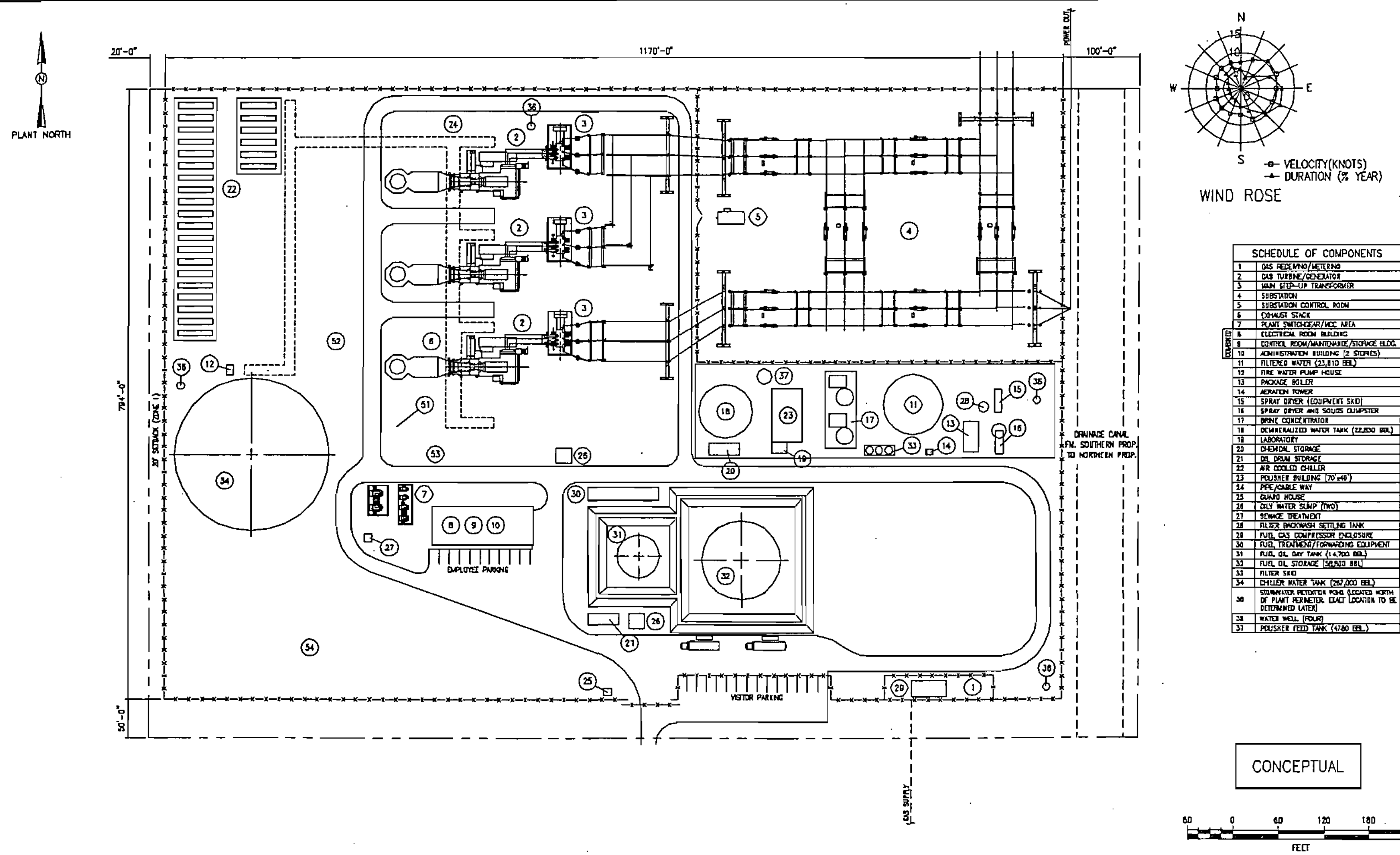
Ben Jacoby, MDC*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, DEP SED
Chair, St. Lucie County BCC
Blair Burgess, P.E., ENSR

Clerk Stamp

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

Charlotte J Hayes 2/14/01
(Clerk) (Date)

Best Available Copy



SCHEDULE OF COMPONENTS	
1	GAS RECEIVING/METERING
2	GAS TURBINE/GENERATOR
3	MAIN STEP-UP TRANSFORMER
4	SUBSTATION
5	SUBSTATION CONTROL ROOM
6	EXHAUST STACK
7	PLANT SWITCHGEAR/MCC AREA
8	ELECTRICAL ROOM BUILDING
9	CONTROL ROOM/MAINTENANCE/STORAGE BLDG.
10	ADMINISTRATION BUILDING (2 STORIES)
11	FILTERED WATER (23,810 BBL)
12	FIRE WATER PUMP HOUSE
13	PACKAGE BOILER
14	AERATION TOWER
15	SPRAY DRYER (EQUIPMENT SKID)
16	SPRAY DRYER AND SOLIDS DUMPSTER
17	BRINE CONCENTRATOR
18	DEMINERALIZED WATER TANK (22,850 BBL)
19	LABORATORY
20	CHEMICAL STORAGE
21	OIL DRUM STORAGE
22	AIR COOLED CHILLER
23	POLISHER BUILDING (70'x40')
24	PIPE/CABLE WAY
25	GUARD HOUSE
26	OILY WATER SUMP (TWO)
27	SEWAGE TREATMENT
28	FILTER BACKWASH SETTLING TANK
29	FUEL GAS COMPRESSOR ENCLOSURE
30	FUEL TREATMENT/FORWARDING EQUIPMENT
31	FUEL OIL DAY TANK (14,700 BBL)
32	FUEL OIL STORAGE (58,800 BBL)
33	FILTER SKID
34	CHILLER WATER TANK (267,000 BBL)
30	STORMWATER RETENTION POND (LOCATED NORTH OF PLANT PERIMETER. EXACT LOCATION TO BE DETERMINED LATER)
38	WATER WELL (FOUR)
37	POLISHER FEED TANK (4780 BBL)

COMBINED (items 8–10)

NO.	REVISION - DESCRIPTION	BY	DATE	CHK'D	APP'D
C	GENERAL REVISIONS	JDG	10/19/00		
B	GENERAL REVISION	WW	10/12/00		
A	ISSUED PRELIMINARY	JDG	08/25/00		

DWG. NO. | REFERENCE DRAWING TITLE

DWG. STATUS: PREL'Y / BID / CONSTR. / CADDS — CHECKED BY / DATE — APPROVED BY / DATE / BY / DATE

PLOT DATE: 10/19/2000 - 13:33
FILE NAME: 531M3381.DWG

CONSTRUCTION YR
DRAWN: ESE 8/00
FILE NO. -531M3381M.DWG
SCALE 1"=60'-0" @ 34"x22"

Enron Engineering & Construction Co.

FIGURE 1-2
MIDWAY ENERGY CENTER
(3) GE 7FA SIMPLE CYCLE
PLOT PLAN
ST. LUCIE COUNTY, FLORIDA

CONSTRUCTION DWG. NO. M3-03-B
SHEET 1 OF 1
REV. NO. C

Facsimile Cover Sheet

To: Mr. Jeff Koerner

Company:
Phone:
Fax: 850-921-9533

From: Charles Schneider
Company: Enron
Phone: 713-345-1789
Fax: 713-646-3253

Date: January 25, 2005
Pages including this cover page: 2

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

COPY

January 19, 2005

Ms. Yi Zhu
Division of Air Resource Management
Department of Environmental Protection
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Yi:

We have been asked by your department to provide an Annual Operating Report (AOR) for the Midway Energy Center (#1110099) and the Ft. Pierce Repowering Project (#1110102).

Please note that neither of these projects operated or commenced any construction activities in calendar year 2004. Also be aware that Enron has suspended all project development activity and does not expect to commence construction on these projects in the future.

Given these facts, please accept this letter in lieu of our submittal of an AOR for 2004.

Sincerely,

Charles E. Schneider
Managing Director

FAX TRANSMITTAL LETTER

Date: January 27, 2005

To: Charles Schneider, Enron (713-345-1789)
Scott Deboth, Enron (713-345-2680)
Fax: 713-646-3253

From: Jeff Koerner, Air Permitting South Program
DARM – Bureau of Air Regulation
Phone: 850/921-9536 Fax: 850/921-9533

Subject: Ft. Pierce Re-Powering Project (No. 1110102-001-AC)
Midway Energy Center Project (No. 1110099-002-AC and 1110099-003-AC)

Pages: 1

I have been in contact with Scott regarding the above projects. It is my understanding that, although Enron holds air construction permits for these two projects, no construction activities were ever started. Enron has suspended all development activities related to these projects. I also received a copy of a letter (dated January 19, 2005) written to Yi Zhu, the Division of Air Resource Management's contact for emissions inventory issues. The letter documents that Enron is no longer pursuing either project. I have marked each facility as "Inactive" in our database. This should prevent future requests for annual operating reports for these facilities.

If you have any questions, please contact me at the number above.

FLORIDA

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

December 15, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

Re: DEP File No. 1110099-002-AC (PSD-FL-304)
Midway Energy Center
Three Simple Cycle Combustion Turbines

Dear Mr. Jacoby:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Midway Energy Center to be located near Port St. Lucie and Fort Pierce in St. Lucie County. The Department's Intent to Issue Air construction Permit and the "Public Notice of Intent to Issue Air Construction Permit" are also included.

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

Please submit any other written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address or contact him at 850/921-9523.

Sincerely,

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

CHF/al

Enclosures

BEST AVAILABLE COPY

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) H. Wyatt

B. Date of Delivery 12-22-00

C. Signature X H. Wyatt ☐ Agent ☐ Addressee

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

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

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

2. Article Number (*Copy from service label*)
7099 3400 0000 1453 3280

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

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

7099 3400 0000 1453 3280

Article Sent To:
Mr. Ben Jacoby, Director

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

Name (Please Print Clearly) (to be completed by mailer)
Mr. Ben Jacoby, Director
Street, Apt. No.; or PO Box No.
1400 Smith Street
City, State, ZIP+4
Houston, Texas 77002-7631

PS Form 3800, July 1999 See Reverse for Instructions

February 2, 2001

Mr. Al Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

Re: DEP File No. 1110099-002-AC (PSD-FL-305)
Midway Energy Center, St. Lucie County
Comments on Draft PSD Permit

Dear Mr. Linero:

This letter serves to provide comments on the draft permit for the above-referenced facility. The Department issued the Draft Permit, Technical Evaluation and Preliminary Determination on December 15, 2000. Comments are provided below, in the order in which they occur in the draft permit.

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If you should have any questions concerning these comments, please do not hesitate to contact me at (713) 853-3161.

Sincerely,

David A. Kellermeyer
Authorized Agent

Attachment

cc: Greg Krause
Raimund Grube
Ben Jacoby
Scott Osbourn, ENSR

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

January 23, 2001

RECEIVED
JAN 24 2001
BUREAU OF AIR REGULATION

Mr. Al Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: DEP File No. 1110099-002-AC (PSD-FL-305)
Midway Energy Center, St. Lucie County

Dear Mr. Linero:

We appreciate the time you and your staff have taken to review and discuss our air permit application for our Midway site in St. Lucie County.

As promised, enclosed with this letter, please find a copy of suggested language for Conditions 13 and 14 of Section III. The objective of this proposal is to capture the language suggested by your staff in our meeting last week. We therefor trust that the attached will address any remaining concerns, and demonstrate our shared interest at further controlling the proposed facility's emissions through operational initiatives. We will call you in the next couple of days to follow up on this and other items.

Again, we appreciate the time you and your staff have taken on this matter, which will help to ensure that the State of Florida has adequate electric capacity to meet its needs.

Sincerely,
Midway Energy Center, LLC

David A. Kellermeyer

David A. Kellermeyer
Authorized Agent

Attachment

cc: Greg Krause
Raimund Grube
Ben Jacoby
Scott Osbourn, ENSR

ATTACHMENT

13. Maximum allowable hours: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any calendar year, as may be adjusted in condition 14 below, based on oil fired run hours. ~~The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any calendar year.~~ No single combustion turbine shall operate more than 5,000 hours in a single year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: ~~The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period. The Department may waive this requirement during the first 24 months of operation based on natural gas availability.~~ In order to encourage the maximum use of natural gas as fuel, during any calendar year the three stationary gas turbines shall operate on fuel oil for no more than an average of 1,000 hours per installed unit. Furthermore, during any calendar year, the maximum allowable operating hours referenced in condition 13 above shall be reduced by two hours for each oil fired hour in excess of an average of 500 per installed unit. For example, if the three stationary gas turbines operate on fuel oil in any calendar year for an average of 550 hours per installed unit, the total maximum allowable operating hours shall be decreased to 3,400.
[Rule 62-212.400, F.A.C. (BACT)]

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

JAN 19 2001

4APT-ARB

RECEIVED
JAN 23 2001
BUREAU OF AIR REGULATION

Mr. Alvaro A. Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation, Division of
Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Comments on Preliminary Determination and Draft PSD Permit for Midway Energy Center, located in St. Lucie County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for the Midway Energy Center dated December 15, 2000. The draft PSD permits are for the proposed construction of an electric power generating plant consisting of three simple cycle combustion turbines (CTs), one natural gas heater and associated fuel storage tanks. The combustion turbines proposed for the facility will be General Electric (GE) PG7241FA units with a nominal generating capacity of 170 megawatts (MW) each. The CTs will combust pipeline quality natural gas and distillate oil. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist and particulate matter (PM/PM_{10}).

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

1. Section III. Emission Units Specific Conditions, Applicable Standards and Regulations, 6.: 40 C.F.R. Subpart Dc is an applicable requirement for the gas heater. In 40 C.F.R. § 60.41c, a steam generating unit is defined as a device that combusts any fuel and produces steam or heat water or any other heats transfer medium. Heat transfer medium is defined as any material that is used to transfer heat from one point to another point. The natural gas heaters meet the definition of steam generating unit; therefore, they are an affected facility as defined in 40 C.F.R. § 60.40c(a). Also, pursuant to 40 C.F.R. § 60.48c(g), the permittee must record the amount of each fuel combusted each day. Please include this applicable requirement in the permit.

2. Section III. Emission Units Specific Conditions, General Operation Requirements, 13. Maximum allowable hours: To limit the potential to emit, the operation limitations (hours of operation per year) should be expressed in terms of 12 consecutive months, rather than

calendar year. This 12-month consecutive limit prevents the enforcing agency from having to wait for long periods of time to establish a continuing violation before initiating enforcement.

3. Section III. Emission Units Specific Conditions, Excess Emissions, 25.: The Florida Department of Environmental Protection should include definitions of what constitutes "startup" and "shutdown" as referenced in this section.

Thank you for the opportunity to comment on the preliminary determination and draft PSD permit for Midway Energy Center. If you have any questions regarding these comments, please direct them to either César Zapata at (404) 562-9139 or Jim Little at (404) 562-9118.

Sincerely,

Paul Wagner

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

cc: C. Holladay
B. Jacobs, MDC
B. Burgess, P.E., ENSR
J. Bunyak, NPS
I. Goldman, DEP SED

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

FACSIMILE TRANSMITTAL SHEET

To	Al Linero - FDEP
Fax Number	(850) 922-6979
From	César Zapata Air and Radiation Technology Branch, Air Permits Section Phone: (404) 562-9139 Fax: (404) 562-9095 E-mail: zapata.cesar@epa.gov
Subject	Midway Energy Center
Date	January 19, 2001
Pages	3 (including this sheet)

Original letter will be sent by mail.

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

JAN 19 2001

4APT-ARB

Mr. Alvaro A. Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation, Division of
Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Comments on Preliminary Determination and Draft PSD Permit for Midway Energy Center, located in St. Lucie County, Florida

Dear Mr. Linero:

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4APT-ARB

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Bureau of Air Regulation, Division of
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Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

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Thank you for the opportunity to comment on the preliminary determination and draft PSD permit for Midway Energy Center. If you have any questions regarding these comments, please direct them to either César Zapata at (404) 562-9139 or Jim Little at (404) 562-9118.

Sincerely,

Paul Wagner

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

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

DEP File No. 1110099-002-AC (PSD-305)
Midway Energy Center, Units 1 – 3
St. Lucie County

Enclosed is the Final Permit Number PSD-FL-305 to construct three 170-megawatt dual-fuel combustion turbines with inlet chillers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Midway Energy Center to be located in St. Lucie County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 2/14/01 to the person(s) listed:

Ben Jacoby, MDC*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, DEP SED
Chair, St. Lucie County BCC
Blair Burgess, P.E., ENSR

Clerk Stamp

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

Charlotte J. Hayes 2/14/01
(Clerk) (Date)

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Ben Jacoby, Director
Midway Development Co., L.L.C.
1400 Smith St.
Houston, Texas 77002-7631

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* H. WYATT

B. Date of Delivery 2-20-01

C. Signature X H. Wyatt ☐ Agent ☐ Addressee

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

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

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

2. Article Number *(Copy from service label)*
7099 3400 0000 1449 3799

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

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

7099 3400 0000 1449 3799

Article Sent To:
Mr. Ben Jacoby, Director

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

Name *(Please Print Clearly) (to be completed by mailer)*
Mr. Ben Jacoby
Street, Apt. No.; or PO Box No.
1400 Smith St.
City, State, ZIP+4
Houston, Texas 77002-7631

PS Form 3800, July 1999 See Reverse for Instructions

FINAL DETERMINATION
File No. 1110099-002-AC (PSD-FL-305)
MIDWAY DEVELOPMENT COMPANY, L.L.C.
510 MW SIMPLE CYCLE FACILITY

The Department distributed a Public Notice package on December 18, 2000 for the project to construct a nominal 510-megawatt (MW) natural gas and fuel oil-fired simple cycle facility to be known as the Midway Energy Center near Port St. Lucie and Fort Pierce in St. Lucie County. The project consists of three nominal 170 MW General Electric 7FA combustion turbine-electrical generators, three 150-foot stacks, a 2.5 million gallon fuel oil storage tank, a 0.6 million gallon fuel oil "day" tank, and other ancillary equipment.

The Public Notice of Intent to Issue was published on December 21, 2000 in The Tribune. Written comments were received from EPA Region IV and the applicant, Midway Development Company, L.L.C (Midway - an affiliate of Enron North America).

The written comments (in italics) are addressed below. Each is followed by the Department's response.

EPA Comments

1. *Section III. Emission Units Specific Conditions, Applicable Standards and Regulations, 6.: 40 C.F.R. Subpart Dc is an applicable requirement for the gas heater. In 40 C.F.R. § 60.41c, a steam generating unit is defined as a device that combusts any fuel and produces steam or heat water or any other heats transfer medium. Heat transfer medium is defined as any material that is used to transfer heat from one point to another point. The natural gas heaters meet the definition of steam generating unit; therefore, they are an affected facility as defined in 40 C.F.R. § 60.40c(a). Also, pursuant to 40 C.F.R. § 60.48c(g), the permittee must record the amount of each fuel combusted each day. Please include this applicable requirement in the permit.*

   The Department agrees with EPA and the requirements of 40 CFR Subpart Dc will be included for the heaters.

2. *Section III. Emission Units Specific Conditions, General Operation Requirements, 13. Maximum allowable hours: To limit the potential to emit, the operation limitations (hours of operation per year) should be expressed in terms of 12 consecutive months, rather than calendar year. This 12-month consecutive limit prevents the enforcing agency from having to wait for long periods of time to establish a continuing violation before initiating enforcement.*

   The Department agrees with EPA and the hours per year will be changed to read 12 consecutive months.

3. *Section III. Emission Units Specific Conditions, Excess Emissions, 25. The Florida Department of Environmental Protection should include definitions of what constitutes "startup" and "shutdown" as referenced in this section.*

The Department does not allow extended operation at low loads, during which such emissions typically occur. The facility must also employ good operating practices to allow excess emissions.

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

The Department will progressively implement EPA's comments for future projects as we get emissions data from facilities required to demonstrate compliance by CEMS. As drafted, the permit includes Specific Conditions (22, 23, 24, 44, 45) related to excess emissions during startup, shutdown, and valid, documented malfunctions. See condition 43 of Section III of this permit for provisions that relate to excluding periods of CEM system data recorded for NO_X and CO for episodes of startup, shutdown and malfunction. However, these periods are recorded and reported as excess emissions as stated in conditions 24 and 45.

Gas turbine startup is the commencement of operation of a gas turbine which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, or pollution control device imbalances, which may result in elevated emissions. Shutdown is the process of bringing a gas turbine off line and ending fuel combustion.

Midway's comments:

4. *Section II. Administrative Requirements, Specific Condition (SC) 8 (page 5 of 15): At our request, the permit expiration date was extended. However, we believe it was the Department's intent to revise the language as follows: "The expiration date is June 30, 2003. Physical construction shall be complete by December 31, 2002~~3~~."*

   The typographical error was corrected to read 2002.

5. *Section III. General Operation Requirements, SC 13 and 14 (pages 7 and 8 of 15): As suggested in a separate letter to the Department, dated January 23, 2001, it's requested that the language in SC 13 and 14 be revised. The suggested language below provides the Department with reasonable assurance that the intent is for natural gas to be the primary fuel for this proposed project:*

   Specific Condition 13 - Maximum allowable hours: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any calendar year, as may be adjusted in condition 14 below, based on oil fired run hours~~. The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any calendar year~~. No single combustion turbine shall operate more than 5,000 hours in a single year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

   Specific Condition 14 - Fuel oil usage: ~~The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period. The Department may waive this requirement during the first 24 months of operation based on natural gas availability.~~

In order to encourage the maximum use of natural gas as fuel, during any calendar year the three stationary gas turbines shall operate on fuel oil for no more than an average of 1000 hours per installed unit. Furthermore, during any calendar year, the maximum allowable operating hours referenced in condition 13 above shall be reduced by two hours for each oil fired hour in excess of an average of 500 per installed unit. For example, if the three stationary gas turbines operate on fuel oil in any calendar year for an average of 550 hours per installed unit, the total maximum allowable operating hours shall be decreased to 3,400.

[Rule 62-212.400, F.A.C. (BACT)]

Note: In a phone conversation with Midway representatives on February 8, the company further proposed to reduce to 250 hours the level at which the "2 for 1" trigger would kick in. Therefore if the three stationary gas turbines operate on fuel oil in any calendar year for the permitted average of 1000 hours per installed unit, the total maximum allowable operating hours shall be decreased to 2,000 hours.

The Department met with Midway representatives on January 17 to discuss these matters. The Department emphasized that a major part of the Best Available Control Technology (BACT) is the use of natural gas. The company argued that there is not yet enough firm supply of natural gas to insure that in a given year or in a given 12-month period they can commit to firing more gas than fuel oil.

Apparently Florida Gas Transmission (FGT) Phase IV and V (and proposed Phase VI) Expansions extend to points North and West of the planned Midway site. Therefore Midway will rely on interruptible supply from the existing FGT capacity in Southeast Florida if it chooses to purchase gas from FGT. This situation could change as FGT considers possible future capacity expansion in Southeast Florida.

The approved Gulfstream Pipeline will extend from Manatee County and includes segments to St. Lucie and Belle Glade. This presents another opportunity for Midway to obtain gas. Additionally, Enron (parent of Midway) has announced a possible project involving construction of a liquefied natural gas (LNG) handling terminal in the Bahamas together with a pipeline to the Southeast Florida Coast.

If the company actually uses more fuel oil than gas, then a better effort needs to be made to reduce emissions while firing fuel oil. For example, nitrogen oxides (NO_X) emissions while firing fuel oil are 42 parts per million by volume dry (ppmvd), whereas emissions while firing natural gas are only 9 ppmvd.

Midway and other companies argue that the NO_X guarantee while burning fuel oil is still 42 ppmvd from General Electric. They are not willing to commit to further wet injection to reduce emissions to less than the guaranteed values. However, it is clear that lower emissions are feasible with wet injection than indicated by the guarantees. For example, initial compliance tests on a GE 7FA simple cycle combustion turbine at the JEA Kennedy Plant indicated NO_X emissions of 30 ppmvd @15% O_2. The added costs in terms of reduced lifetime and increased maintenance are unknown.

There is already a requirement (within Section III, Condition 19) for Midway to develop a NO_X reduction plan when the hours of oil firing reach 500 hours per year per unit. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised.

The Department concludes that Midway's proposed draft permit revision, the fuel oil use hammers, and the various gas supply options will encourage Enron to make sure more gas becomes available for its planned Midway Project as well as for its other projects planned in Broward County. The permit will be modified accordingly.

It is noted that Midway's potential to emit will be significantly reduced because maximum oil use will reduce total hours of operation by an average of 1500 per unit. For example, potential NO_X emissions from the facility will be reduced from roughly 735 tons per year to approximately 600 tons per year.

6. <u>*Section III. SC 17 (page 8 of 15):*</u> *The permit language states that "The permittee shall provide manufacturer's emissions vs. load diagrams for the DLN and wet injection systems prior to their installation." Past requests of the manufacturer for these types of diagrams have been unsuccessful. Typically, the manufacturer will provide emission estimates at various load points corresponding to various inlet temperature cases. These emission values, that are the basis for this permit, were previously provided in the permit application. It's requested that the word "diagrams" in the above sentence be replaced with the word "estimates".*

   The Department has regularly obtained such diagrams from operators throughout the State. The Department will to change the language from "prior to installation" to "upon installation and completion of testing" for submittal of the required diagrams.

7. <u>*Section III. SC 19 (page 9 of 15):*</u> *The language concerning fuel oil firing should be revised as follows: "In addition, NO_X emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd at 15% O_2 to be demonstrated by <u>initial</u> stack test."*

   The Department revised this condition to include the word initial as suggested. Reference to Method 20 will be added for consistency with the previous condition.

8. <u>*Section III. SC 20 (page 9 of 15):*</u> *The CO emission limit for fuel oil presented in the permit application was based on 20 ppmvd. At a temperature of 30 °F, this corresponds to 69.6 lb/hour, not 46 lb/hour, as shown in the draft permit. The 20 ppm concentration is based on 100% load. Concentrations of CO are estimated to be as high as 22 ppm at 75% load factor and 30 ppm at 50% load factor. The peak emission estimate is 78.3 lb/hour at 50% load and 91°F. Based on these factors we request that the permit limit for oil firing be expressed as follows: "The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 31 lb/hr (gas) and neither 20 ppmvd nor 70 lb/hour (fuel oil) to be demonstrated by stack tests at full load operation."*

   This condition will be revised as suggested. The Department notes, however, that initial testing of General Electric 7FA combustion turbines indicates emissions in the range of 0.5 to 2 ppm whether burning natural gas or fuel oil. Such results have been observed at TECO Polk Power, JEA and City of Tallahassee facilities.

The Department will monitor long-term performance on CO at some of the combined cycle units that have continuous emissions monitors. This may result in lower emission limits issued to applicants for combustion turbine projects in the future.

9. Section III. SC 27 (page 10 of 15): *The last sentence should be revised as follows: "...periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. ~~18 and~~ 19."*

   This condition was revised to read 19.

10. Section III. SC 29 (page 11 of 15): *The permit language indicates that emission testing by EPA Reference Methods 9 and 10 (for visible emissions and CO emissions, respectively) are to be conducted both initially and annually for both fuels. In the past, the Department has issued permits (e.g., Hines Energy Complex) with language that requires that annual testing be done on fuel oil (the backup fuel) only if a threshold number of operating hours on oil is exceeded (e.g., 400 hr/CT) during a rolling 12-month period. This is because it's a financial hardship to require operation on the more expensive fuel. It's requested that the conditions be revised to include annual testing for VE and CO emissions on oil, only if a CT exceeds 400 hours of operation in a 12-month rolling period.*

    The Department does not consider it to be a financial hardship for Midway to test for CO and VE while firing fuel oil and it is not clear that fuel oil is exclusively just the back-up fuel. In the case of Hines, the allowable hours on fuel oil operation are much lower than the hours on natural gas operation. At Midway, the fuel oil firing can be very significant compared with natural gas. Additionally, permitted CO emissions are much higher than for the fuel oil case than for the natural gas case.

11. Section III. SC 33 (page 11 of 15): *It's requested that the same language be included here regarding the annual testing requirement for visible emissions while firing oil.*

    See discussion in 10 above.

12. Section III. SC 36 (page 12 of 15): *The second sentence should be revised as follows: "...corrected for the average inlet ~~ambient~~ air temperature during the test...".*

    The Department will revise this condition as suggested.

13. Section III. SC 45 (page 13 of 15): *The last sentence states that "these excess emissions periods shall be reported as required in Specific Conditions 24 and 46." The reference to SC 24 appears to be incorrect, as it refers to the limitation for visible emissions.*

    The reference to Specific Condition 24 in Specific Condition 45 will be revised to read Specific Condition 27.

14. Section III. SC 46 (page 14 of 15): *Although the language is intended to instruct on the procedure to determine compliance with the 24-hour rolling average, the second sentence refers to a separate compliance determination being conducted at the "end of each operating day". This language is appropriate in the context of a 24-hour*

block average, but should be deleted from SC 46, which is addressing rolling averages.

This condition was revised to read 24-hour block average.

15. <u>*Section III. SC 47 (page 14 of 15):*</u> *The Specific Conditions referenced in the last sentence of this condition (20, 21 and 29) all appear to be incorrect. The conditions need to be cross-referenced correctly or deleted. Also, the appropriate DEP office to notify would be the Southeast District, not the South District.*

    This condition was revised to read reference to Specific Conditions 18, 19 and 24. The District office was changed as suggested.

16. <u>*Section III. SC 49 (page 14 of 15):*</u> *Some of the text appears to be missing. There doesn't appear to be any schedule for testing of sulfur or nitrogen in natural gas in the bulleted items. In fact, the bulleted items appear to be related to compliance with the Acid Rain requirements of Parts 72 and 75, not with Part 60 Subpart GG compliance (which is what requires a Custom Fuel Schedule).*

17. <u>*Section III. SC 50 (page 15 of 15):*</u> *It's requested that the requirement to conduct sampling and analysis for fuel bound nitrogen content be deleted. Typically, the requirement to monitor water-to-fuel ratio, combined with the requirement to analyze for fuel bound nitrogen content, provides a surrogate for NO_X compliance. As recognized by the Department in the language of SC 48, the NO_X CEMS are to be used in lieu of the water/fuel monitoring system for reporting excess emissions. Given that NO_X CEMS will be used for compliance, the monitoring of the fuel bound nitrogen content serves no useful purpose, and should not be required.*

    The Department replaced the above conditions with the new condition (SC 49) below. The requirements of the 40CFR60, Subpart GG will be attached as Appendix GG. This new Appendix includes all the Department requirements regarding this Subpart GG.

New Specific Condition 49:

<u>Fuel Sulfur Records</u>: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

Compliance with the fuel sulfur limit for *natural gas* shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

Compliance with the *fuel oil* sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

18. *Particulate Limits: The Department has determined that measurement of front-half catch by EPA Method 5 is sufficient to demonstrate the BACT emission limit for PM_{10}.*

EPA Method 5 measuring the front-half catch only is now specified for compliance with the PM_{10} standard. Because the back-half catch is excluded, the emission limits are reduced from 18 to 10 and from 34 to 17 pounds per hour while firing natural gas and fuel oil respectively. These values are equal to previous BACT determination for GE 7FA simple cycle units.

CONCLUSION

The Department will issue the permit with the changes noted above.

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

PERMITTEE:

Midway Development Company
1400 Smith Street
Houston, Texas 77002-7631

Permit No.	PSD-FL-305
File No.	1110099-002-AC
SIC No.	4911
Expires:	June 30, 2003

Authorized Representative:

Ben Jacoby

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers; one 2.5-million gallon fuel oil storage tank; one 0.6 million gallon fuel oil storage tank; a natural gas heater; and three 80-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located Northwest of the intersection of I-95 and W. Midway Road near Port St. Lucie and Ft. Pierce in unincorporated St. Lucie County. UTM coordinates are Zone 17; 556.7 km E; 3028.5 km N.

STATEMENT OF BASIS:

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

Attached Appendices and Tables made a part of this permit:

Appendix GG	40 CFR 60 NSPS, Subpart GG
Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes
Howard L. Rhodes, Director
Division of Air Resources
Management

"More Protection, Less Process"

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SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers, three 80-foot stacks, one 2.5-million gallon fuel oil storage tank, one 0.6-million gallon storage tank, a gas heater and ancillary equipment. Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSION UNIT	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
004	Fuel Storage	One 2.5-Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	One 0.6 Million Gallon Fuel Oil Storage Tank
006	Fuel Heating	One 13 million Btu per hour Natural Gas heater

REGULATORY CLASSIFICATION

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

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 12/21/00 Notice of Intent published in The Tribune, St Lucie County
- 12/18/00 Distributed Intent to Issue Permit
- 11/09/00 Received Application

RELEVANT DOCUMENTS:

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

- Application received on November 9, 2000
- Letters from Enron North America dated December 5, 2000; January 23, and February 2, 2001.
- Letter from U.S. EPA Region IV dated January 19, 2001
- Department's Intent to Issue and Public Notice Package dated December 15, 2000
- Updated application received from Enron North America on January 17, 2001
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the *Permitting Authority*: Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the *Compliance Authority*: DEP Southeast District office, 400 North Congress Avenue W, West Palm, Florida, 33401 and phone number 561/681-6755, fax 561-681-6755. Copies shall be sent to the DEP Port St. Lucie Branch office, 1801 SE Hillsmoore Dr, C 204, Port St. Lucie, Florida 34952 and phone number 561/398-2806, fax 561/398-2815.

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

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

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

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

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

7. BACT Determination Revision: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will

also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing (e.g. conversion to combined-cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

8. Completion of Construction: The permit expiration date is June 30, 2003. Physical construction shall be complete by December 31, 2002. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

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

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

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

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southeast District and a copy to the DEP's Port St. Lucie Branch offices by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

13. Quarterly Reports: Semiannual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (2000 version), shall be submitted to the DEP's Southeast District and a copy to the DEP's Port St. Lucie Branch offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

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

3. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

4. ARMS Emission Unit 004, Fuel Storage, consisting of one 2.5 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Unit 005, Fuel Storage, consisting of one 0.6 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. ARMS Emission Unit 006, Fuel Heating, consisting of one 13 million Btu per hour natural gas heater to heat natural gas used by the combustion turbines. This unit shall comply with applicable requirements of 40CFR60, Subpart Dc.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in these units.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
{Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

8. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 30 °F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,700 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,900 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing.
[Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Southeast District as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.
[Rule 62-4.130, F.A.C.]

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

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any consecutive 12-month period. This

amount shall be reduced by two hours for each fuel oil-fired hour in excess of an average of 250 per installed unit. No single combustion turbine shall operate more than 5,000 hours in any consecutive 12-month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any consecutive 12-month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

Control Technology

15. Dry Low NO_X (DLN-2.6) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

16. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems upon completion of initial testing. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology.

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	11/17 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC (not PSD)	As Above	2.8 ppmvd @15% O_2 (Gas or Fuel Oil)
CO	As Above	9 ppmvd @15% O_2 (Gas) 20 ppmvd @15% O_2 (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	2 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and limited Fuel Oil usage	9 ppmvd @15% O_2 (Gas) 42 ppmvd @15% O_2 (Fuel Oil)

19. Nitrogen Oxides (NO_X) Emissions:

- *While firing Natural Gas*: The emission rate of NO_X in the exhaust gas shall not exceed 9 ppmvd @15% O_2 on a 24-hr block average as measured by the continuous emission monitoring system (CEMS) in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 62 pounds per hour nor 9 ppmvd @15% O_2 to be demonstrated by the initial stack test using EPA Method 20. [Rule 62-212.400, F.A.C.]
- *While firing Fuel Oil*: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd @15% O_2 on the basis of a 3-hr block average as measured by the CEMS in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd @15% O_2 to be demonstrated by initial stack test using EPA Method 20. [Rule 62-212.400, F.A.C.]
- *NO_X Reduction Plan*: The permittee shall develop a NO_X reduction plan when the hours of oil firing reach 500 hours per year per unit. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without adversely affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. [Rule 62-212.400, F.A.C., BACT Determination].

20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 9 ppmvd @15% O_2 nor 31 lb/hr (gas) and neither 20 ppmvd @15% O_2 nor 70 lb/hr (fuel oil) at 30°F to be demonstrated by stack tests. [Rule 62-212.400, F.A.C.]

21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas shall exceed neither 2.8 ppmvd @15% O_2 nor 6 lb/hr (gas or fuel oil) to be demonstrated by initial stack tests. [Non-applicability of Rule 62-212.400, F.A.C.]

22. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Emissions: SO_2 and SAM emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or No. 2 distillate fuel oil with a maximum 0.05 percent sulfur for 1000 hours per year per unit. Emissions of SO_2 shall exceed neither 11 lb/hr (natural gas) nor 104 lb/hr (fuel oil). Emissions of sulfuric acid mist shall exceed neither 2 lb/hr (natural gas) nor 16 lb/hr (fuel oil). These emissions shall be measured by applicable compliance methods described below. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]

23. Particulate Matter (PM/PM_{10}): PM/PM_{10} emissions shall exceed neither 10 lb/hr (gas) nor 17 lb/hr (fuel oil) to be demonstrated by initial stack tests. [Rule 62-212.400, F.A.C.]

24. Visible Emissions: Visible Emissions shall not exceed 10 percent opacity to be demonstrated by visual observation tests.
[Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. Excess Emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

26. Excess Emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southeast District within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Following the NSPS format, 40 CFR 60.7 Subpart A, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 19.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (2000 version)].

COMPLIANCE DETERMINATION

28. Compliance Test Schedules: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit and as required by the *Compliance Authority*. [Rules 62-204.800 and 62-4.070(3) F.A.C.]

- *Initial*: Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors.
- *Annual*: Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated.
- *Prior Permit Renewal*: All tests shall be conducted within 12 months prior permit renewal.

29. Reference Methods: The following reference methods as described in 40 CFR 60, Appendix A (2000 version), and adopted by reference in Chapter 62-204.800, F.A.C. shall be used to demonstrate compliance with the allowable emissions limits. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

    - EPA Reference Method 5, "Determination of Particulate Matter Emissions from Stationary Sources" (I).
    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for NO_X compliance with 40CFR60 Subpart GG.
    - EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements.
    - EPA Reference Method 25A, "Determination of Total Hydrocarbon Concentrations." Correction for methane by EPA Method 18 is allowed. Initial test only.

30. Compliance with CO emission limits: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75

31. Compliance with the VOC emission limits: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.

32. Compliance with the NOx emission limits: Compliance with the NO_X emissions limits shall be determined by stack tests and a CEMS as specified in specific conditions 30, 45 and 46.

33. Compliance with the PM/PM_{10} and VE emission limits: Initial and annual tests are required for visible emissions (VE). Initial stack test is required for PM/PM_{10}. Tests for PM and VE shall be conducted concurrently.

34. Continuous compliance with the PM/PM_{10}, SO_2 and sulfuric acid mist emission limits: Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and the restricted use of No. 2 distillate fuel oil (or superior grade) are the methods for determining continuous compliance for PM/PM_{10}, SO_2 and sulfuric acid mist.

35. Test Method for Natural Gas and Fuel Oil Sulfur Content: For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM D 2880-71 (or equivalent) for sulfur

content of *liquid fuel* and ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of *gaseous fuel* shall be utilized in accordance with the EPA-approved custom fuel monitoring schedules. Natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Refer to Appendix GG.

36. Testing procedures: Initial testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average inlet air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for compressor inlet temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

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

38. Test Notification: The DEP's Southeast District and the DEP's Port St. Lucie Branch District offices shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

39. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

40. Test Results: Compliance test results indicating the results of the required compliance tests shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie Branch District offices no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

42. Notifications: All notifications and reports required by 40 CFR60, Subpart A shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie Branch District offices.

MONITORING REQUIREMENTS

43. Continuous Monitoring System Procedures: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the NO_X emissions from each CT. Each device shall properly function prior to the initial performance tests and comply with the applicable monitoring system requirements of 40 CFR 75.62. Upon request from DEP, the CEMS emission rates for NO_X on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 62-4.130, F.A.C and 40CFR75]

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

45. Continuous Monitoring System Operation: The continuous monitoring systems (CEMS) for NO_X shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Valid hourly emission rates shall not include periods of startup, shutdown, fuel switching, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as require in Specific Conditions 27 and 46.
[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 60.13, 40 CFR 75].

46. Continuous Compliance with the NO_X Emission Limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on a 24-hour block average (gas) and 3-hr block average (oil). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of 24-hr (gas) and 3-hr (oil) valid hourly

measurements from the previous operating hours. A valid hourly emission rate shall be calculated for each hour (during which fuel is fired) in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction unless prohibited by Rule 62-210.700, F.A.C.
[Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

47. CEMS for Reporting Excess Emissions: The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (2000 version). Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40 CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15 % oxygen) are above the permit limits listed in Specific Conditions 18 and 19 shall be reported to the DEP Southeast District office as required in Specific Condition 24.

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

49. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

Compliance with the fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

50. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Midway Energy Center
PSD-FL-305 and 1110099-002-AC
St. Lucie County, Florida

BACKGROUND

The applicant, Midway development Company, L.L.C. (Midway, an affiliate of Enron North America) proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Midway Energy Center, East of Arcadia in unincorporated St. Lucie County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 80-foot stacks. Midway proposes to operate these units up to 3,500 hours per year per unit of which 1000 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated December 15, 2000, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on November 9, 2000 (revised December 5) and included a proposed BACT proposal prepared by the applicant's consultant, ENSR.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	9 ppmvd @ 15% O_2 (gas)[1] 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (1000 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	9 ppmvd (gas, baseload) 30 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	2 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

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

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by Midway is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the Midway Energy Center.

A National Emission Standard for Hazardous Air Pollutants (NESHAP) under development exists for stationary gas turbines. However this facility will not be subject to the NESHAP or to a requirement for a case-by-case determination of maximum achievable control technology because HAP emissions will be less than 10 TPY.

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple cycle turbines. Two (Carson and McClellan) were permitted in ozone non-attainment areas and two (Lakeland and PREPA) were permitted as continuous duty projects. The proposed Midway Energy Center is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 11/00. 1000 hrs on oil
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 10/00. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 2/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Issued. Gas only
Tenaska Heard, GA	960	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Issued. 1000 hrs on oil.
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
RockGen Cristiana, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous DLN = Dry Low NO_X Combustion FO = Fuel Oil GE = General Electric
SC = Simple Cycle SCR = Selective Catalytic Reduction NG = Natural Gas WH = Westinghouse
INT = Intermittent HSCR = Hot SCR WI = Water or Steam Injection ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	2.8 lb/hr – NG 7.5 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly

with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

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

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

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

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Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Midway project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 1000 hours per year (per CT).

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

NO_X Control Techniques

Wet Injection

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

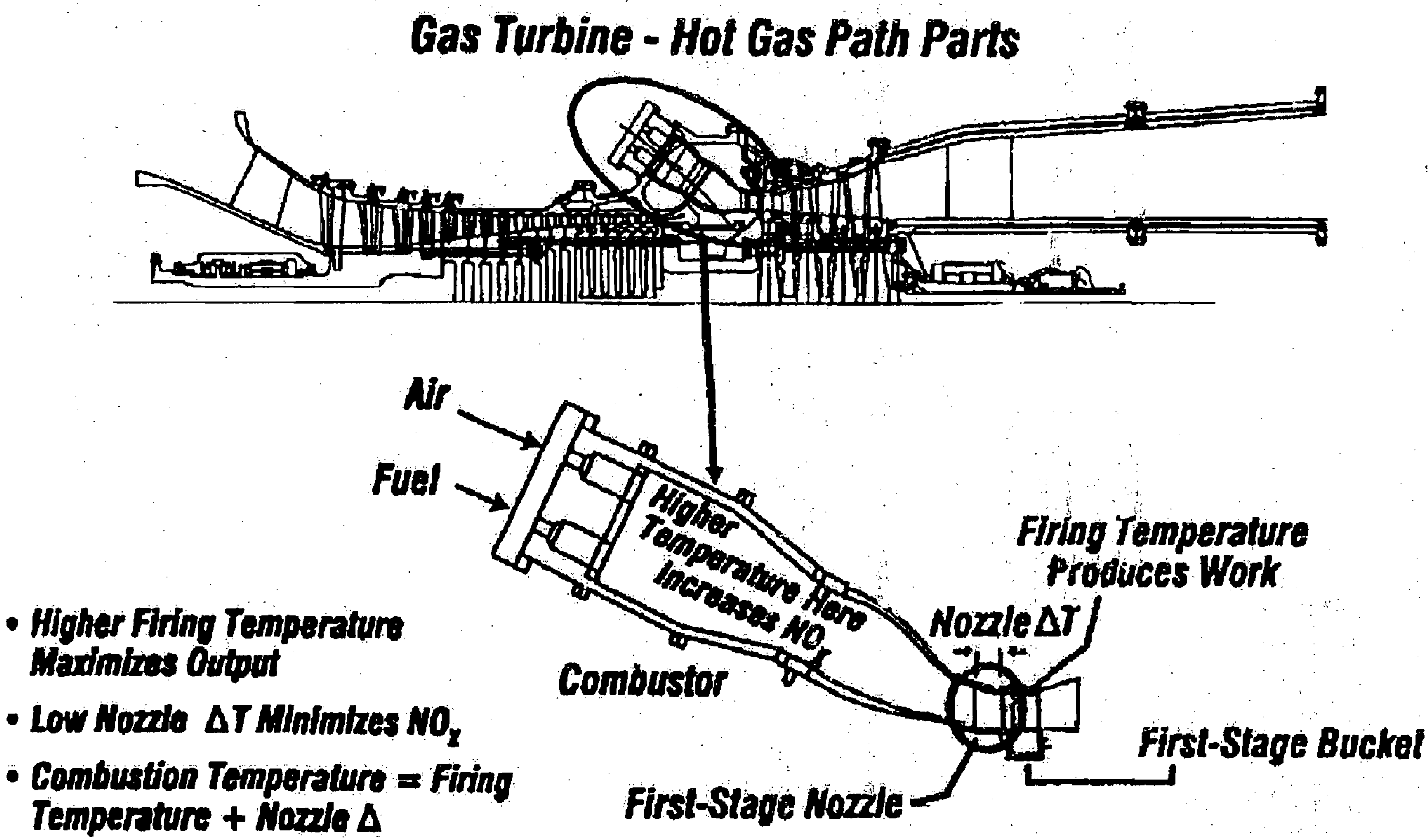

Figure 1 – Relation Between Flame Temperature and Firing Temperature

Combustion Controls

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

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X.

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd while burning natural gas. The results are all superior to the emission characteristics given in Figure 3.

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

Emissions characteristics by wet injection NO_X control while firing oil are shown in Figure 4 for the DLN-2.0, a predecessor of the DLN2-6. Operation on fuel oil is not in the premixed mode. Tests at the JEA[2] Kennedy Plant indicated that 30 ppmvd is achievable on a short-term basis.

Specialized premixed DLN burners for fuel oil operation were installed in a project in Israel[3] where water is scarce, but the Department has no information on the results. Mitsubishi (who also make a 501F) is developing a dual-fuel premixed DLN. Optimization of premix fuel-air nozzle and performance was verified in high-pressure combustion tests. Commissioning tests on gas and oil burning were completed at an undesignated site.[4] The details are not available in English.

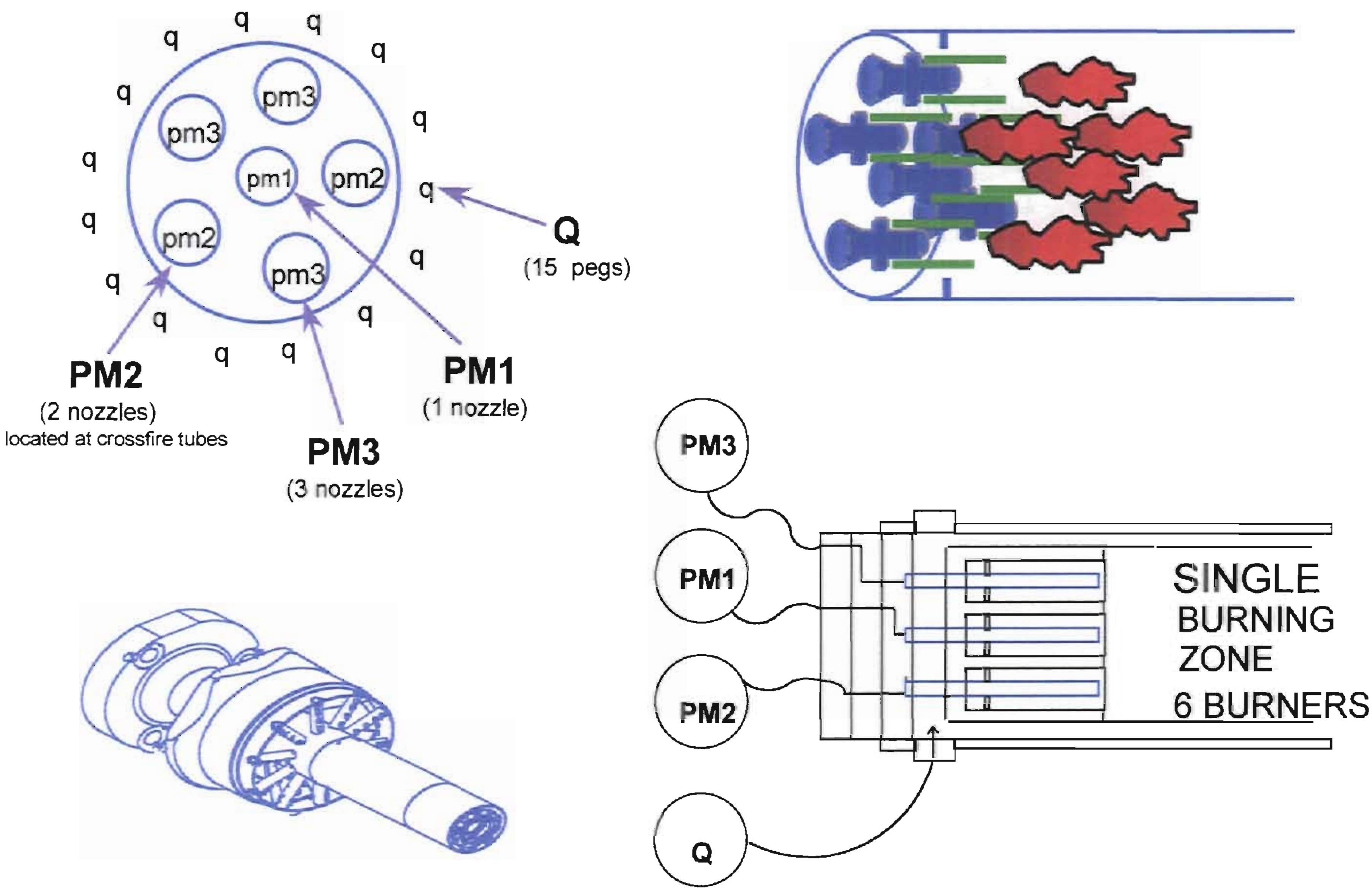

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

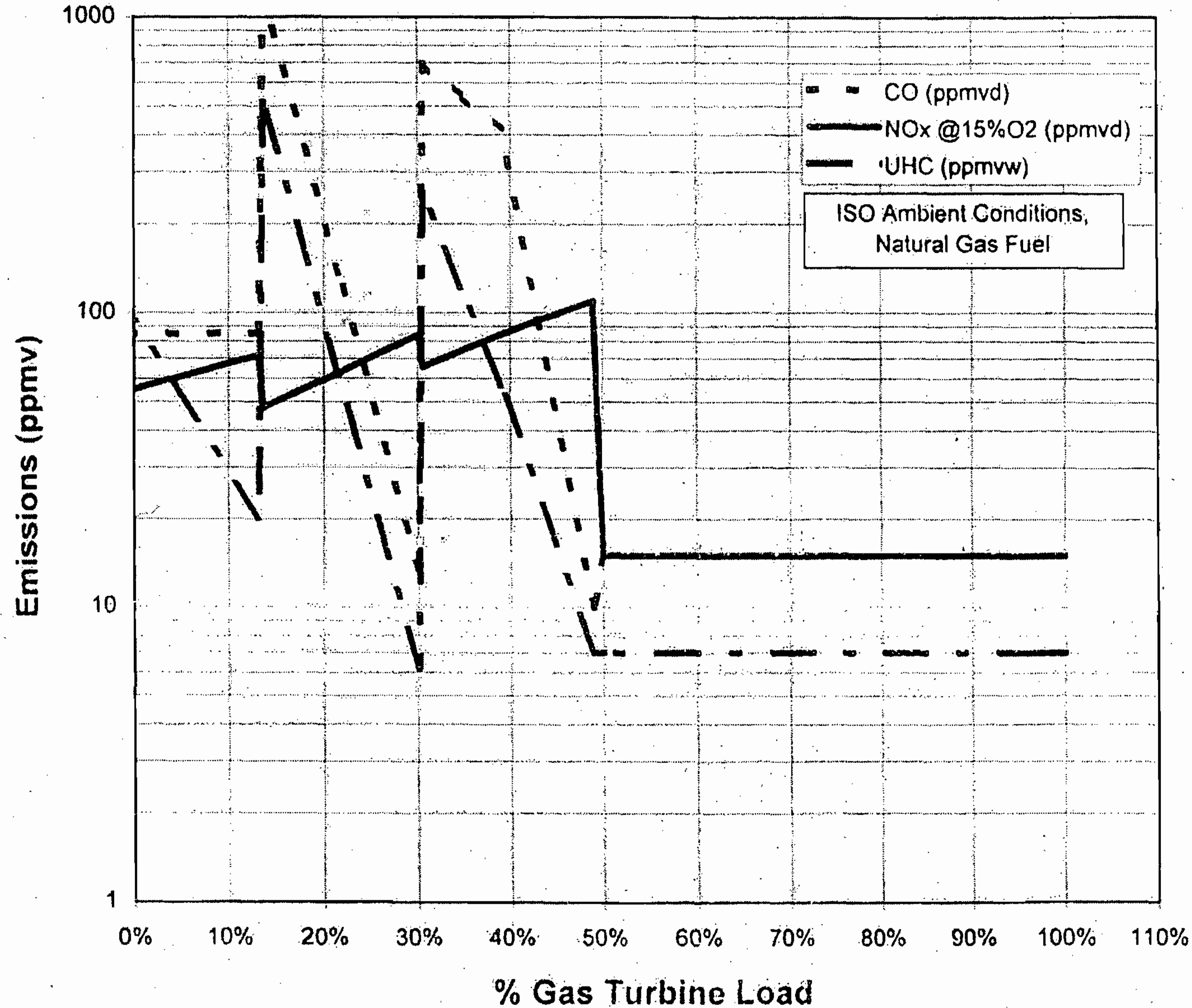

Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

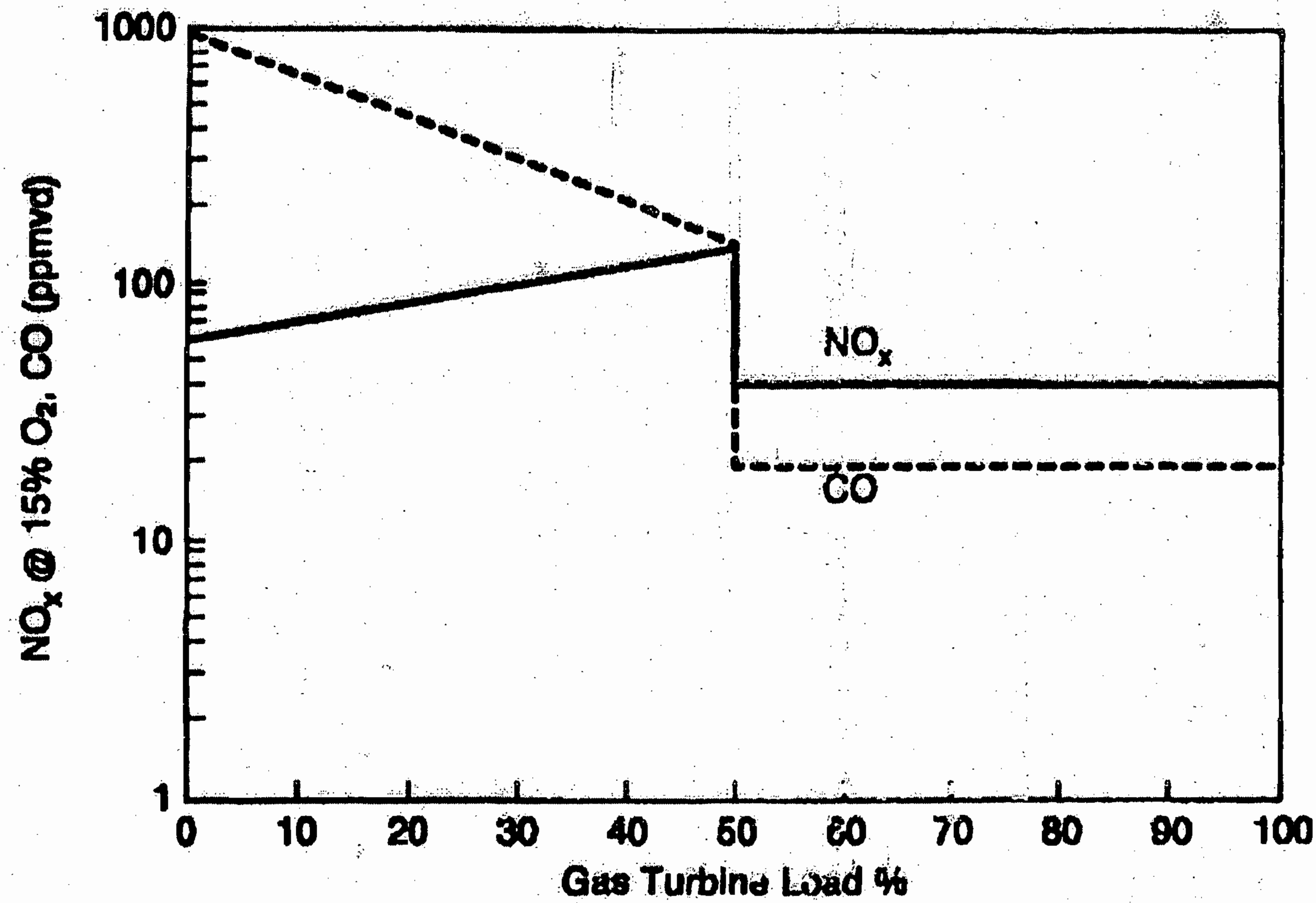

Figure 4 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 5 from an EPRI report.[5] Basically developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 5.

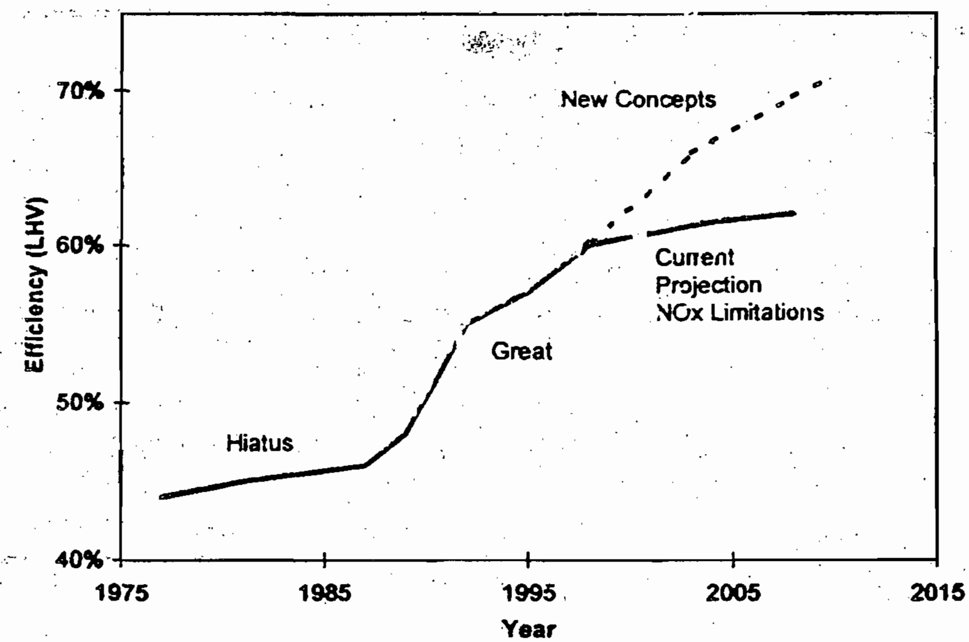

Figure 5 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by Midway. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air-cooling.

Catalytic Combustion: XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[6] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

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

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[7] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma which documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

Recently, Catalytica and GE announced that the XONON™ combustion system has been specified as the *preferred* emissions control system with GE 7FA turbines that have been ordered for Enron's proposed 750 MW Pastoria Energy Facility.[8] The project will enter commercial operation by the summer of 2001. However actual installation of XONON™ is doubtful.

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

Selective Catalytic Combustion

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

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

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998.

Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 (Paynes Creek) project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority,[9] FPC, TECO, and Competitive Power Ventures will install SCR on combined cycle projects to achieve 3.5 ppmvd. Limits as low as 2 ppmvd NO_X have been specified using SCR on combined cycle F Class projects in various parts of the country.

Selective Non-Catalytic Combustion

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

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

$SCONO_X$™

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

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

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

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X. [13] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmv.

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[14]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

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

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

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 190 TPY of SO_2 and 29 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grain of sulfur per 100 standard cubic feet (gr S/100scf). This value is well below the "default" maximum value of 20 gr. S/100 scf, but high enough to require a BACT determination.

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 1000 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 119 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[15]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 9 and 30 ppmvd for gas and oil respectively at baseload proposed in Midway's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Midway for this project are 1.4 ppmvw for gas and fuel oil firing at baseload. These limits are sufficient to keep annual emissions of VOC below the 40 TPY threshold and a BACT determination is not required. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[16]

BACKGROUND ON PROPOSED GAS TURBINE

Midway plans to install three nominal 170 MW General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

Typically, companies obtain a guarantee from GE to achieve 9 ppmvd NO_X during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation. With the frequent start-ups and shutdowns of the units, some applicants are concerned about the ability to maintain the low NO_X values for long periods of time. As a result, some of them agreed to a "new and clean" limit of 9 ppmvd but requested a continuing BACT limit of 10.5 ppmvd.

As detailed in the table above, the Department has issued quite a number of permits for simple cycle GE 7FA requiring achievement of 9-10.5 ppmvd without the requirement of any additional control equipment. The ones with limits of 9 ppmvd are allowed to operate for as many as 1000 hours per year on back-up fuel oil whereas the ones permitted at 10.5 ppmvd are allowed only 750 hours per year of fuel oil. A smaller GE unit known as the 7EA can routinely achieve 9 ppmvd NO_X or lower based on numerous installations in Florida and elsewhere. The 7EA has a lower flame temperature, compression ratio, and power rating (85 versus 170 MW) than the 7FA.

The ability to meet a NO_X emission limit of 9 ppmvd by DLN technology involves a substantial efficiency and energy penalty as previously discussed. For example, the 7FA is characterized by a 15.5:1 compression ratio, a 2400 °F firing temperature, 56 percent efficiency, and produces 263 MW in combined cycle. On the other hand, GE offers a more efficient F-Class model known as the 7FB, but guarantees a NO_X limit of 25 ppmvd by DLN.

The 7FB is characterized by an 18.5:1 compression ratio, a 2500 °F firing temperature, 57.3 percent efficiency, and produces 280 MW in combined cycle. The clear implication is that the

power penalty to reduce NO_X from 25 to 9 ppmvd by DLN technology alone is on the order of 20 MW for a combined cycle (roughly 13 MW on a simple cycle unit).[17]

Another example of this point is the ABB GT24. It is characterized by a 30:1 compression ratio and 58 percent efficiency in combined cycle. The unit is guaranteed to meet 25 ppmvd of NO_X. The simple cycle version is rated at 183 MW compared to 170 for the GE7FA.

It is not surprising that some compromises were made by ABB, which resulted in greater power and efficiency but slowed progress toward single-digit NO_X emissions. According to ABB, "rather than just concentrating on ever lower NO_X levels, ABB has chosen a total solution that limits pollutants and at the same time increases energy efficiency."[18] A lower compression, lower efficiency version of the ABB GT24 might be capable of 15 ppmvd NO_X or less by DLN technology.

The results during the "new and clean" test of the GE PG7241 at the Polk Power Station (discussed above) are nothing short of spectacular in comparison with the permitted emission limits. It is doubtful that these values can be maintained indefinitely. However, there is good reason to believe that performance will continue to be better than the permitted emission limits. For reference, the values while burning oil were equally good in comparison to the permitted limits for CO and VOC, whereas the NO_X emissions were very close to the permitted value of 42 ppmvd @15% O_2. Visible emissions were 0 percent opacity when firing natural gas or fuel oil.

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

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Midway project assuming full load. Values for NO_X and CO are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions Nos. 18 through 23.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 10/17 lb/hr – Gas/Fuel Oil (Front-half)
CO	As Above	9 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	As Above	2 grain of sulfur per 100 ft^3 gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	9 ppmvd – Gas 42 ppmvd – F.O. for 1000 of 3,500 hrs

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are Hot SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- Hot SCR is not commonly required as BACT on simple cycle combustion turbines. Although it was required on the fuel oil-fired PREPA project (to achieve 10 ppmvd), the requirement has been removed from the permit. It is noted that the specification of the fuel oil was 0.15 percent sulfur. This does not imply that hot SCR it is not technically feasible for intermittent duty simple cycle combustion turbines firing natural gas with 0.05 percent sulfur fuel oil as back-up fuel.
- Hot SCR is required at the simple cycle continuous duty Lakeland McIntosh Unit 5 project if the Westinghouse 501 G unit fails to achieve 9 ppmvd while firing natural gas. Hot SCR was considered cost-effective because the unit will operate continuously and the expected NO_X reduction is from 25 to 9 ppmvd).
- The levelized costs of NO_X removal by Hot SCR for the Midway Project were estimated by ENSR at $20,700 per ton assuming 3,500 hours of dual-fuel operation. The estimates are based on emissions controlled to 4.5 and 7.5 ppmvd @15% O_2 NO_X while burning gas and fuel oil respectively and 5 ppmvd @15% O_2 ammonia slip.
- The levelized costs of NO_X removal by Hot SCR for the DeSoto project were estimated by Golder at $11,350 per ton assuming 3,390 hours of operation on natural gas and a reduction to 3.6 ppmvd on gas and 17 ppmvd on fuel oil. The estimates are based on an ammonia slip of 9 ppmvd for gas and 12 ppmvd for oil.
- The Department does not accept the precise hot SCR cost calculations presented by Midway and considers them on the high end. The costs calculated by Golder for the DeSoto Project are probably more accurate. With the actual performance of the GE 7FA at TECO Polk Power Station with no add-on control (5-8 ppmvd @15%O_2), it is easy to see that hot SCR would not be cost-effective. Hot SCR is rejected as BACT.
- The Department will limit operation of the three units to 3,500 hours per year per unit. No single unit may operate more than 5,000 hours per year to insure that the conclusion regarding cost-effectiveness remains applicable.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out

the possibility of $SCONO_X$. XONON is available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X. This value is equal to that required at the Lakeland continuous duty combustion turbine, which has an alternative hot SCR requirement.
- Typical permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them.
- The 9 ppmvd limit at Oleander, Vandolah, Shady Hills, DeSoto, Virginia Power, and Midway while firing natural gas is the lowest known BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42-ppmvd limit for limited fuel oil firing is typical.
- The gas-based NO_X emission limit of 9 ppmvd will be difficult to maintain over short term averaging times. That is the main reason why some operators cannot provide reasonable assurance they can meet such a low limit by DLN. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into an emissions limit with a long-term averaging time for continuous duty. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion.
- The Department issued permits for the TEC Polk Power, JEA Brandy Branch, and Reliant Osceola Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander, Vandolah, Shady Hills, and DeSoto.
- The proposed BACT limit of 9 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO_X is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[20]
- Based on test results at the JEA Kennedy Plant, it is possible that the NO_X emissions while firing oil from may be reduced from 42 to 30 ppmvd. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.

- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.
- The fuel oil-based NO_X emissions limit of 42 ppmvd can be maintained over a short-term averaging period by varying the amount of water injected. The Department has determined that a 3-hour averaging time is appropriate.
- The Department's overall BACT determination is equivalent to approximately 0.4 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- The applicant estimates VOC emissions of 1.4 ppmvd while firing gas and 1.4 ppmvd while burning fuel oil. The Department will set the limits at 2.8 ppmvd because at this concentration, the project will still not trigger PSD or a requirement for a BACT determination.
- The Department will set CO limits achievable by good combustion at full load as 9 ppmvd @15% O_2 (gas) and 20 ppmvd (oil). These values are in the lower range of values from permitted or proposed simple cycle units. These limits are equal to or lower those proposed by the Department for the Oleander, Vandolah, DeSoto, Reliant, JEA Brandy Branch, and TEC Polk Power projects.
- Midway estimated levelized costs for CO catalyst control at $31,800 per ton. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- Golder evaluated the use of oxidation catalyst for the DeSoto project with 90 percent control efficiency. Golder estimated levelized costs for CO catalyst control at $7,500 per ton.
- The cost of CO control by oxidation catalyst is probably closer to the Golder estimate based on reducing *permitted* CO emissions. However in view of the performance of GE 7FA units without add-on control (~1 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- The Department will not set a continuous CO limit reflecting the "new and clean test" because GE will not guarantee it. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.
- There is no benefit in penalizing the applicant or with a lower limit at this time just because the performance at another site was far better than guaranteed or expected.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limits for PM_{10} will be set at 10 pounds per hour during gas operation and 17 pounds per hour while operating on fuel oil. These values are based on front-half catch.

- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power, DeSoto Power, Vandolah, Shady Hills and quite a number of combined cycle projects.

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Carbon Monoxide	Annual Method 10
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (gas - 24-hr block average) (oil – 3-hr block average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed. During gas operation, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C.
SO_2 and SAM	Custom Fuel Monitoring Schedule- Refer to Appendix GG

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
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Recommended By:

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

Date: 2/14/01

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 2/14/01

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NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

11. Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable NOx emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NOx emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

<u>Department requirement</u>: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 10.0 for natural gas and 10.6 for fuel oil. The equivalent emission standards are 108 and 102 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

12. Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

13. Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

<u>Department requirement</u>: The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.

[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

<u>Department requirement</u>: The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

<u>Department requirement</u>: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

14. Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as pro-vided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\,e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

where:

NOx = emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.

Noxo = observed NOx concentration, ppm by volume.

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

Po = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20

following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: The permit species sulfur testing methods and allows the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Florida Department of

Memorandum Environmental Protection

TO: Howard Rhodes

THRU: Clair Fancy

FROM: Al Linero 2/12
Teresa Heron

DATE: February 12 , 2000

SUBJECT: Midway Energy Center
Three 170 MW Combustion Turbines
DEP File No. 1110099-002-AC (PSD-FL-305)

Attached is the final package for construction of three dual-fuel, intermittent duty, simple cycle, 170 MW GE 7FA combustion turbines with inlet air chillers, two fuel oil storage tanks, a gas heater, and ancillary equipment at the planned (Enron) Midway Energy Center in St. Lucie County.

NO_X emissions from the combustion turbine will be controlled to 9 ppmvd Dry Low NO_X (DLN-2.6) technology while firing natural gas. The facility may operate 3,500 hours per year per unit. Use of fuel oil (during which emissions of 42 ppmvd are allowed) will be permitted up to 1000 hours per year per unit.

Conditions in the draft permit required Midway to burn more gas than oil. Midway did not petition the permit, but asked relief from this condition based on claims that the gas supply is actually uncertain during the first few years of operation.

To insure there is still a big incentive to fire gas when available and to encourage further development of firm supplies in the area, Midway proposed a condition that will result in cutbacks in total hours of operation after Midway fires 250 hours per year per unit. For example, if Midway actually burns fuel oil for 1000 hours each unit can only operate for 2000 hours.

The permit will also require Midway to examine the possibility of NO_X reductions (from 42 ppmvd) while firing fuel oil. We are aware that JEA achieved 30 ppmvd while firing fuel oil during the initial compliance test at their GE 7FA unit at the Kennedy Plant.

We are reviewing almost two identical applications from Enron in Broward County. I expect similar permits unless any Class I Area issues are raised by the National Park Service.

We recommend your approval of the attached Intent to Issue.

AAL/al

Attachments

Midway Development Company, L.L.C.

Houston, TX

ENSR INTERNATIONAL

PSD Permit Application for the Midway Energy Center

ENSR International
Revised January 2001
Document Number 6792-140-300R

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1.0 INTRODUCTION

1.1 Application Summary

Midway Development Company, LLC is proposing to construct and operate a 510 MW (nominal) simple-cycle combustion turbine peaking electric generating facility in St. Lucie County. The facility, to be known as the Midway Energy Center (MEC), will be located on approximately 30 acres of property near Port St. Lucie, Florida. From an air emissions perspective, the key elements of the proposed action include:

- Three (3) combustion turbines;
- Natural gas fuel heater; and
- Two distillate oil storage tanks.

Midway Development Company, LLC desires to commence construction in April 2001 and begin commercial operation no later than May 1, 2002. These dates are goals, but are highly dependent on the receipt of all necessary local and environmental approvals as well as the availability of the combustion turbines.

As part of its application, the Midway Energy Facility is requesting increased flexibility regarding the ability to burn 1,000 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission ("FGT") pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 Bcf/day during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMbtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for greater oil burning flexibility is necessitated by near term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and oil will be used only to the extent transmission capacity constraints on FGT preclude the delivery of natural gas to the site

Since the proposed action will be a major stationary source under the Part C of the Clean Air Act, MEC is applying to the Florida Department of Environmental Protection (FDEP) for a Prevention of Significant Deterioration (PSD) permit and for a State Air Construction Permit. This application provides technical analyses and supporting data for a permit to construct the facility under the federal PSD program, as well as the state construction permit program. The federal PSD program in Florida is administered by the FDEP under a State Implementation Plan program approved by U.S. EPA under 40 CFR 51.166.

This application addresses the air construction permitting requirements specified under the provision of Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The application is divided into seven additional sections. Section 2.0 presents an overview of the proposed action and processes covered by this permit application. Section 3.0 describes the methods used to calculate facility emissions and provides a summary of expected emissions. Section 4.0 reviews the regulatory requirements with which the facility must comply. Section 5.0 presents a control technology evaluation for those pollutants subject to PSD review. Section 6.0 presents the air dispersion modeling analysis required by PSD and FDEP regulations. Finally, Section 7.0 provides the additional impacts analysis required by PSD regulations.

FDEP application forms are located in Appendix A. Supporting emission calculations are presented in Appendix B. Information supporting the control technology review is presented in Appendix C. BPIP output data for establishing modeling downwash parameters is presented in Appendix D. Appendix E provides a description of the dispersion modeling input data and output files, which have been submitted to FDEP on CD-ROM.

General information about the applicant and the location of the project site, are presented below. A more detailed discussion on the organization of this document is also presented. To facilitate FDEP's review of this document, individuals familiar with both the facility and the preparation of this application have been identified in the following section. FDEP should contact these individuals if additional information or clarification is required during the review process.

1.2 General Applicant Information

Listed below are the applicant's primary points of contact, and the address and phone number where they can be contacted. Since this permit application has been prepared by a third party under the direction of Midway Development Company, L.L.C., a contact has been included for the permitting consultant.

1.2.1 Applicant's Address

Corporate Office	Midway Development Company, LLC 1400 Smith Street Houston, TX 77002-7631
Project Site	Midway Energy Center Northwest of the intersection of I-95 and W. Midway Rd.

St. Lucie County (Port St. Lucie approximately 1.5 km to the southeast)

1.2.2 Applicant's Contacts

Corporate Officer	Ben Jacoby Director 1400 Smith Street Houston, TX 77002-7631
Environmental Contact	Dave Kellermeyer Director 1400 Smith Street, EB-3146 C Houston, TX 77002-7631 Telephone: (713) 853-3161 Fax: (713) 646-3037
Permitting Consultant	Robert Iwanchuk Project Manager ENSR International 2 Technology Park Drive Westford, MA 01886 Telephone (978) 589-3000 X3265 Fax (978) 589-3100

1.3 Project Location

The Midway Energy Center will be located on an approximately 30-acre parcel of rural land located in St. Lucie County, Florida. The site is located northwest of the intersection of I-95 and W. Midway Road. The facility will be connected to electrical transmission lines and a natural gas pipeline located in close proximity to the site. The approximate project property boundary and local road network is shown on Figure 1-1. A detailed representation of the property boundary is shown on the plot plan drawing contained in Figure 1-2. The site exhibits low topographic relief and is currently occupied by an abandoned citrus grove. Stormwater will be handled by the facility's storage water management system, which includes one on-site stormwater detention pond.

Benchmark Universal Transverse Mercator (UTM) coordinates for the plant, corresponding to the middle combustion turbine stack location shown in Figure 1-2 and the power island grade elevation are as follows:

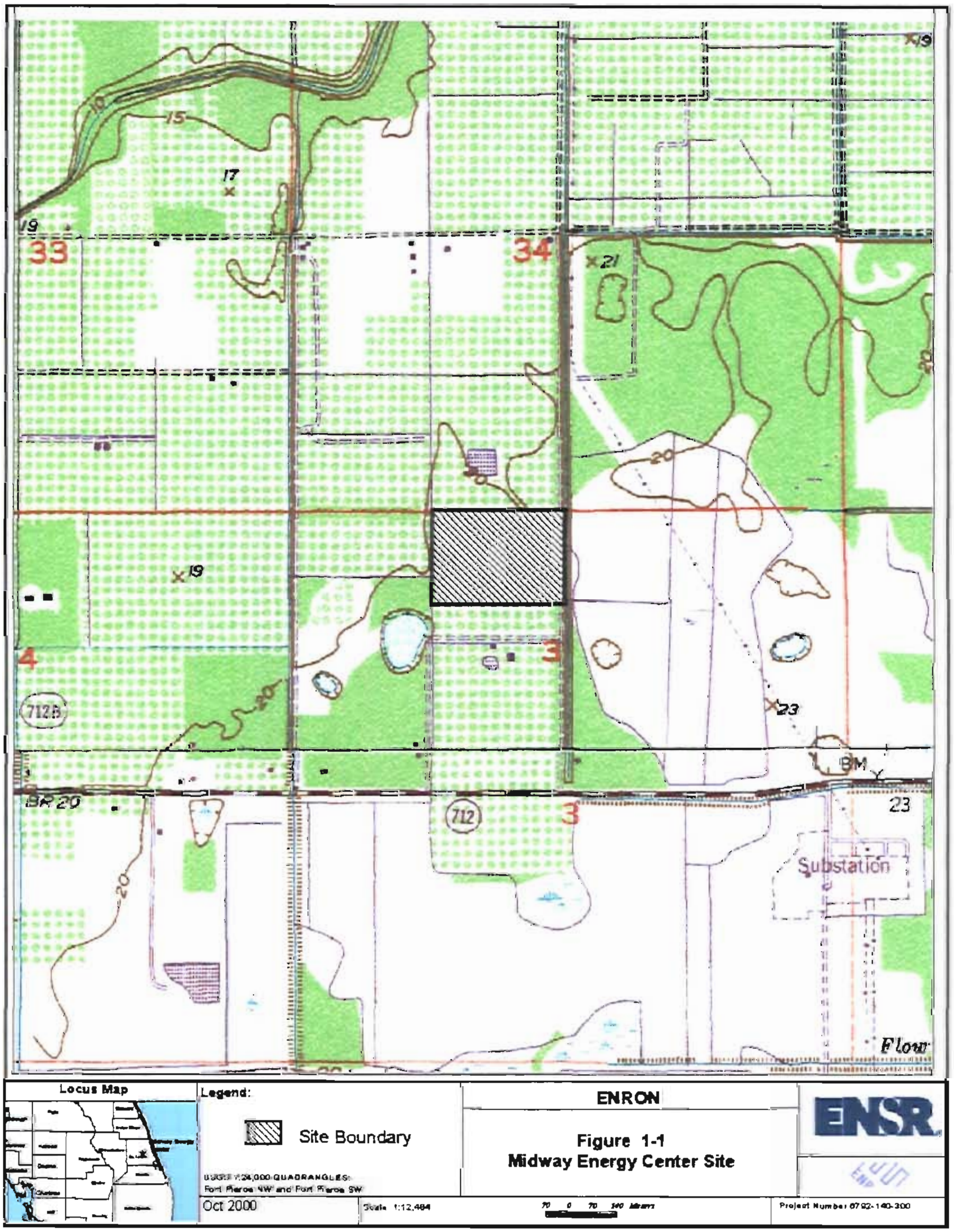
Zone Number	17
Northing (m)	3,028,548
Easting (m)	556,670
Site Elevation (ft msl)	20

1.4 Document Organization

The balance of this document is divided into sections which address the major issues of a preconstruction air quality permit review. The outline below provides an overview of the contents of each of the remaining sections.

- **Section 2.0 - Project Description** provides an overview of the facility including major facility components. A general description of the Simple-Cycle process by which power will be produced at this site is presented.
- **Section 3.0 - Emissions Summary** presents a detailed review of the emissions which will be generated at the project site subsequent to the completion of project development, under normal operating conditions. The basis and methods used to calculate emissions from the project are presented.

Figure 1-1 Site Plan



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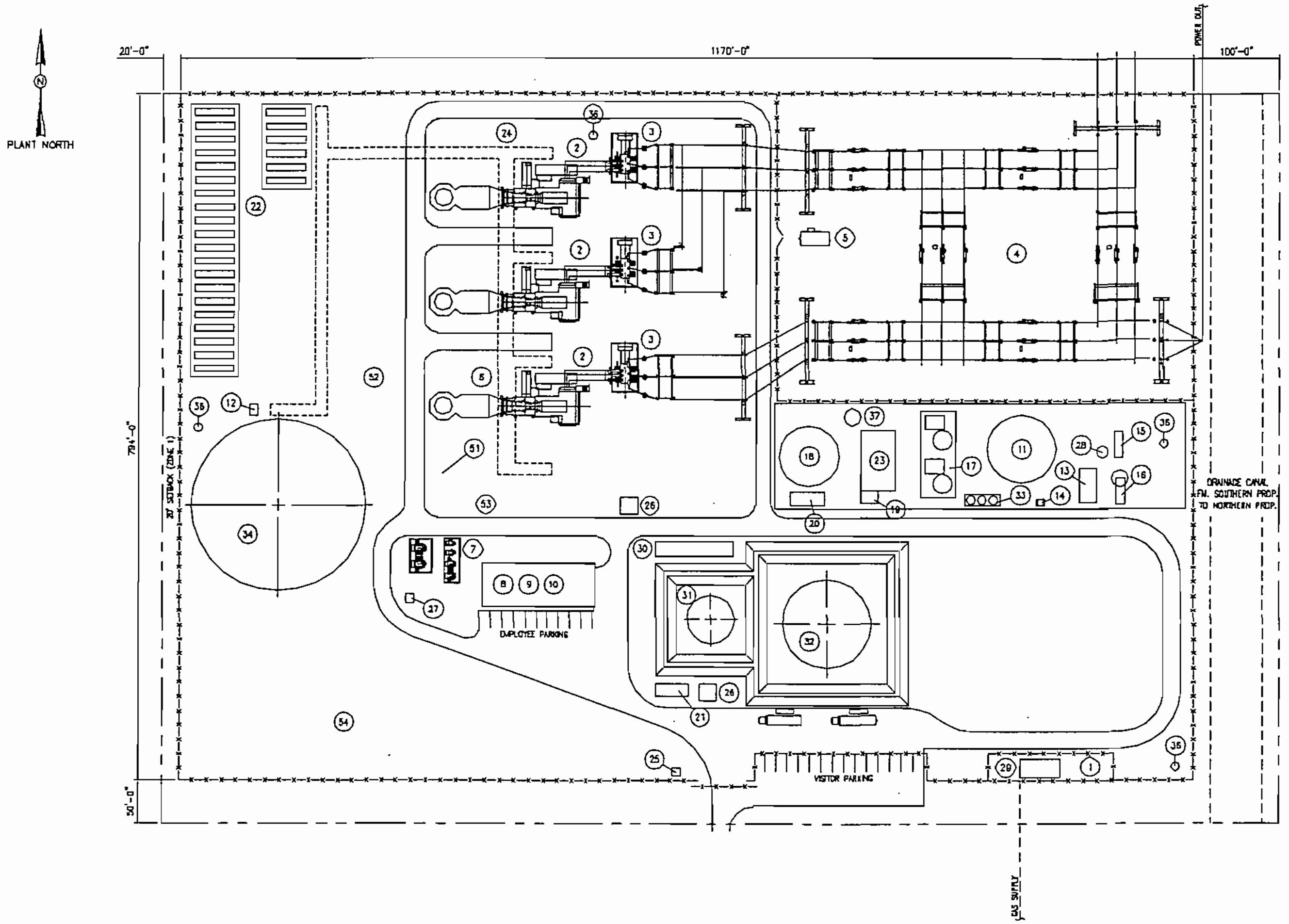
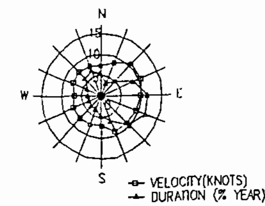




WIND ROSE

SCHEDULE OF COMPONENTS	
1	GAS RECEIVING/METERING
2	GAS TURBINE/GENERATOR
3	MAIN STEP-UP TRANSFORMER
4	SUBSTATION
5	SUBSTATION CONTROL ROOM
6	EXHAUST STACK
7	PLANT SWITCHGEAR/MCC AREA
8	ELECTRICAL ROOM BUILDING
9	CONTROL ROOM/MAINTENANCE/STORAGE BLDG.
10	ADMINISTRATION BUILDING (2 STORIES)
11	FILTERED WATER (23,810 BBL)
12	FIRE WATER PUMP HOUSE
13	PACKAGE BOILER
14	AERATION TOWER
15	SPRAY DRYER (EQUIPMENT SKID)
16	SPRAY DRYER AND SOLIDS DUMPSTER
17	BRINE CONCENTRATOR
18	DEMINERALIZED WATER TANK (22,800 BBL)
19	LABORATORY
20	CHEMICAL STORAGE
21	OIL DRUM STORAGE
22	AIR COOLED CHILLER
23	POLISHER BUILDING (70'x40')
24	PIPE/CABLE WAY
25	GUARD HOUSE
26	OILY WATER SUMP (TWO)
27	SEWAGE TREATMENT
28	FILTER BACKWASH SETTLING TANK
29	FUEL GAS COMPRESSOR ENCLOSURE
30	FUEL TREATMENT/FORWARDING EQUIPMENT
31	FUEL OIL DAY TANK (14,700 BBL)
32	FUEL OIL STORAGE (58,800 BBL)
33	FILTER SKID
34	CHILLER WATER TANK (297,000 BBL)
35	STORMWATER RETENTION POND (LOCATED NORTH OF PLANT PERIMETER. EXACT LOCATION TO BE DETERMINED LATER)
36	WATER WELL PUMP
37	POLISHER FEED TANK (4780 BBL)

COMBINED

CONCEPTUAL

60 0 60 120 180 240
FEET

DWG. NO.	REFERENCE DRAWING TITLE	NO.	REVISION - DESCRIPTION	BY	DATE	CHKD	APPD
		C	GENERAL REVISIONS	JDC	10/19/00		
		B	GENERAL REVISION	WW	10/12/00		
		A	ISSUED PRELIMINARY	JDO	08/25/00		

DWG. STATUS	CHECKED BY	DATE	APPROVED BY	DATE	BY	DATE
PREL'Y						
BID						
CONSTR.						
CADDS						

PLOT DATE: 10/19/2000 - 13:33
FILE NAME: 531M3381.DWG

FA./STA. ACCT. NO.
CONSTRUCTION YR

	BY	DATE
DESIGN		
DRAWN	ESC	8/00
ASBUILT		

FILE NO. -531M3381M.DWG
SCALE 1"=60'-0" @ 34"x22"

Enron Engineering & Construction Co.

FIGURE 1-2
MIDWAY ENERGY CENTER
(3) GE 7FA SIMPLE CYCLE
PLOT PLAN
ST. LUCIE COUNTY, FLORIDA

AFE/WORK ORDER
ASBUILT DWG. NO.
CONSTRUCTION DWG. NO. M3-03-B
SHEET 1 OF 1
REV. NO. C

- **Section 4.0 - Applicable Regulations and Standards** presents a detailed review of both Federal and State regulations. The focus of this section will be on establishing which regulations are directly applicable to the proposed project and for which compliance must be demonstrated.

- **Section 5.0 - Control Technology Evaluation** is a substantial requirement for the PSD application. Since the proposed project will result in a significant increase in the emission of certain criteria pollutants, as defined under PSD regulations, a detailed review of control technologies is provided. Annual "Potential-to-Emit" (PTE) emissions, as defined by FDEP, are expected to be significant for Carbon Monoxide (CO), Particulate Matter ($PM\backslash PM_{10}$), Sulfur Dioxide (SO_2) Nitrogen Oxides (NO_x) and Sulfuric Acid Mist (H_2SO_4). Therefore, control technology analyses for these pollutants have been prepared. The review conforms to the EPA's Top-Down protocol.

- **Section 6.0 - Air Dispersion Modeling Analysis** provides the results of the air quality impact assessment required under the PSD regulations to demonstrate compliance with National Ambient Air Quality Standards (NAAQS), PSD Class II Increments, and the significant impact levels defined for them. The air quality impact analysis predicted no significant impacts; therefore no further modeling for compliance with the NAAQS and PSD increments was required. The air dispersion modeling was done in conformance with EPA modeling guidelines.

- **Section 7.0 - Additional Impacts** contains supplemental information regarding the potential impacts of the project. Specifically this section discusses the potential for impacts on local soils, vegetation, visibility, and growth related air quality impacts. PSD Class I area assessments of regional haze, increment and deposition impacts using the CALPUFF dispersion model will be submitted as a supplement to this permit application.

- **Section 8.0 - References** include a list of the documents relied upon during the preparation of this document.

- **Appendix -** Permit application forms, emission calculations, and supplemental materials supporting the information presented herein are contained in the appendices to this document. Modeling results, both input and output files, are provided on the enclosed CD-ROM.

2.0 PROJECT DESCRIPTION

The following section provides an overview of the facility addressed by this permit application. The facility will be owned and operated by Midway Development Company, LLC. The proposed project is a dual fuel Simple-Cycle merchant power plant to be located near Port St. Lucie, Florida. A merchant power plant is a non-utility generation facility designed to produce power within the emerging deregulated electricity market. The Midway Energy Center is designed to have a nominal generating capacity in the range of 510 MW. Commercial operation is scheduled to commence by May 1, 2002. As a merchant plant in a deregulated electricity market, the MEC is being designed to convert fuel to useful power quickly, cleanly, and reliably.

As part of its application, the Midway Energy Facility is requesting increased flexibility regarding the ability to burn 1,000 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission ("FGT") pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 Bcf/day during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMbtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for greater oil burning flexibility is necessitated by near term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and oil will be used only to the extent transmission capacity constraints on FGT preclude the delivery of natural gas to the site

2.1 Power Generation Facility

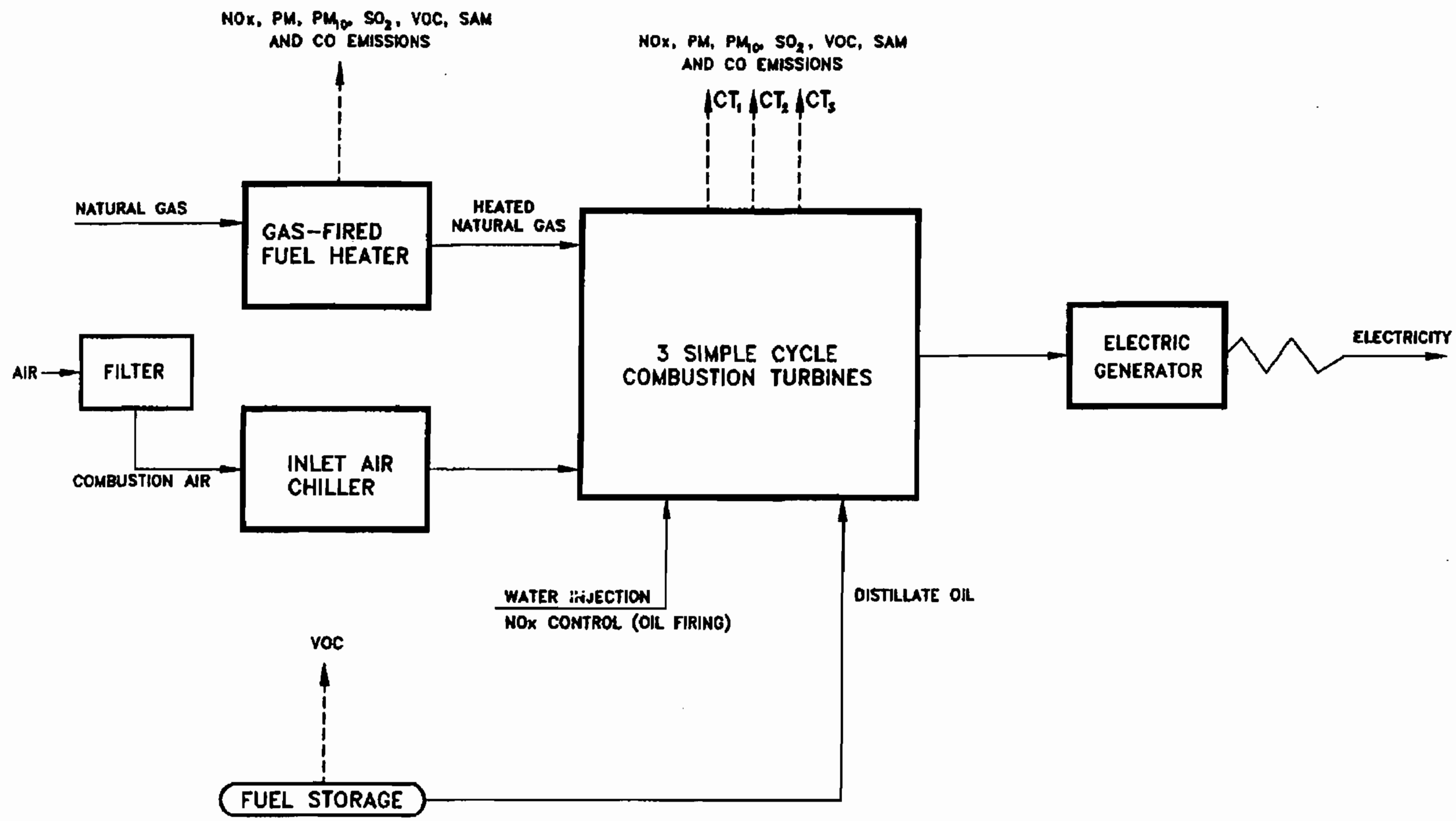
The MEC will include three (3) General Electric 7FA combustion turbine generators (CTGs) operating in Simple-Cycle mode. The CTGs will be designed to operate on both natural gas and low-sulfur diesel oil. Dry, low NO_X combustors will be used to minimize NO_X formation during combustion, and water injection will be employed during diesel oil-firing to reduce NO_X emissions. Each turbine will be equipped with its own exhaust stack.

The proposed generation facility will utilize the Best Available Control Technology (BACT), as defined by U.S. EPA, for NO_X, CO, SO_2, Sulfuric Acid Mist, and PM/PM_{10} to minimize air emissions. The project will not be a major source of hazardous air pollutants.

2.2 Major Facility Components

The primary source of criteria pollutants associated with the MEC are the three combustion turbine generators which exhaust through three separate stacks. A process flow diagram for a simple-cycle combustion turbine is shown in Figure 2-1. There will be a minor amount of emissions associated with the plant's ancillary facilities, including the two diesel fuel storage tanks and a fuel gas heater. A brief description of the major components of the facility is provided in the following sections.

Operating parameters for the combustion turbine at three loads (100%, 75%, 50%), and four ambient temperatures (30°F, 42°F, 50°F, 91°F), are presented in Appendix B. This covers the expected operating range of the facility.



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ENSR CONSULTING AND ENGINEERING

FIGURE 2-1
PROCESS FLOW DIAGRAM
SIMPLE CYCLE COMBUSTION TURBINE
MIDWAY ENERGY CENTER

DRAWN:	JK	DATE:	10/00	PROJECT NUMBER:	REV.
APPV'D:	DD	REVISED:	X	6792-140	0

679209A.DWG

2.2.1 Gas Turbines

MEC proposes to install three (3) General Electric combustion turbine generators in Simple-Cycle mode with independent exhaust stacks. Each turbine will include an advanced firing combustion turbine air compressor, gas combustion system (dry, low NO_X combustors), power turbine, and a 60-hertz (Hz), 13.8 kilovolt (kV) generator. The turbines will run predominantly on pipeline-quality natural gas, but will have the capability to operate on diesel oil. Each turbine is designed to produce a nominal 170 MW of electrical power.

The power output from a combustion turbine generator (CTG) is proportional to the mass flow rate of air and fuel through the expansion (power) turbine. Thus at high ambient temperatures the power available from a CTG is significantly reduced due to the lower density of the inlet air. As the CTG's proposed are intended to provide peak power generation, in an area where ambient temperatures frequently rise above 80°F, the CTG's have been equipped with inlet air chilling equipment. At high ambient temperatures, inlet air chillers will be operated to cool the inlet air to the turbines in order to compensate for the loss of power output due to lower compressor inlet density. At an ambient temperature of 91°F, chilling will reduce the compressor inlet temperature to 50°F resulting in an approximately 24 MW increase in gross power output per CTG unit. The inlet air chillers will operate using a closed loop cooling circuit, with waste heat exhausted to the atmosphere using dry, air-cooled cooling towers. These cooling towers will be of a non-contact design and thus do not represent a source of air emissions.

The gas turbine is the heart of a Simple-Cycle power system. First, air is filtered and compressed in a multiple-stage axial flow compressor. Compressed air and natural gas are mixed and combusted in the turbine combustion chamber. Dry, low NO_X combustors and water injection are used to minimize NO_X formation during combustion, depending on which fuel is fired. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine which drives both the air compressor and electric generator. The exhaust exits the power turbine at atmospheric pressure and approximately 1,100°F.

2.2.2 Simple-Cycle

The MEC will use Simple-Cycle power generation technology to deliver electrical peaking power during periods when short-term demand exceeds base load requirements. Peaking power units are able to be brought on and off-line quickly, in response to nearly instantaneous fluctuations in electricity demand.

2.2.2.1 The Brayton "Simple" Cycle

The production of electricity using a combustion turbine engine coupled to a shaft driven generator is referred to as the Brayton Cycle. This power generation cycle has a thermodynamic efficiency which generally approaches 40%. This is also referred to as "Simple-Cycle" and has been traditionally utilized for electricity peaking generation since the turbine(s) and subsequent electrical output can be brought on line very quickly. The largest energy loss from this cycle is from the turbine exhaust in which heat is discarded to the atmosphere at about 1,100°F.

2.2.3 Fuel Gas System

Pipeline-quality natural gas is delivered to the plant boundary at a sufficient pressure so that no additional fuel compression will normally be required. If gas compression is required, it will be accomplished using an electrically-driven compression system. The gas is first sent through a knockout drum for removal of any large slugs of liquid which may have been carried through from the pipeline. Only one knockout drum is provided.

The natural gas then passes through a filter/separator to remove particulate matter and entrained liquids. The gas flows through the filter/separator's first chamber, the filtration section, where entrained liquid is coalesced on the filter cartridges, drops to the bottom of the chamber and either vaporizes and returns to the main gas stream or drains to the sump below. The gas then flows through the coalescing filters which remove any particulate matter. Next, the gas passes to the second chamber, the separation section, where any entrained liquid remaining in the stream is further separated by impingement on a net or labyrinth and drains to the bottom sump.

The gas is then heated by a natural gas-fired heater, prior to being split for distribution to the three GE turbines. The fuel gas heater is designed for use as a means to prevent condensation of moisture and hydrates in the natural gas used in the CTGs. Each stream is sent through one last knockout drum to protect against the presence of liquid in the fuel. Finally, the gas is delivered to the turbines and combusted as part of the power generation cycle.

2.2.4 Distillate Oil Storage

Diesel fuel will be provided by tanker trucks and stored in two, above-ground storage tanks made of steel. These tanks will also supply fuel to the combustion turbines during diesel oil-firing. On site oil storage requirements have been estimated to be a maximum of 2.5 million gallons, with a maximum day storage tank requirement of 0.6 million gallons.

2.2.5 Ancillary Facilities

Other systems supporting plant operations and safety include:

- Auxiliary Cooling Water System
- Fire Protection System

- Service Water System
- Process Waste Water System
- Potable Water and Sanitary Waste Water System
- Storm Water System
- Plant and Instrument Air System
- Continuous Emissions Monitoring System (CEMS)
- Maintenance Lifting System
- Unit Control System

3.0 PROJECT EMISSIONS

This section discusses the basis and methods used to calculate emissions for the MEC. The section is organized according to the primary emission source groups. Within each section the methods used to calculate emissions and any adjustments that are required appear first, followed by a summary of the emissions resulting from the specific operation or activity.

The calculation procedures used during the development of this application rely on process information developed by MEC for the operations to be conducted at the MEC, manufacturers' data, and methods presented by the U.S. EPA in the "Compilation of Air Pollution Emission Factor, AP-42". The summary presented below has been prepared for each major emission-generating component of the proposed project, which includes:

- Combustion Turbines (3 Units);
- Natural gas fuel heater; and
- Fugitive Emissions from distillate oil storage .

Detailed emission calculations for each emission source or source category are presented in Appendix B.

3.1 Combustion Turbines

3.1.1 Criteria Pollutants

Criteria pollutant emissions are those that contribute to the formation of ambient air concentrations of pollutants for which the EPA has established National Ambient Air Quality Standards (NAAQS) based on health effects criteria. The PSD-regulated criteria pollutant emissions associated with natural gas combustion are CO, NO_X, VOC, SO_2, and Particulates (PM/PM_{10}). The only PSD-regulated non-criteria pollutant expected to be emitted in significant quantities is sulfuric acid mist (SAM).

The primary emission sources at the MEC will be the three(3) combustion turbines. Hourly emissions from these units were calculated from manufacturers' operating parameters and guaranteed in-stack concentrations for CO, NO_X, and VOC. SO_2 emissions were calculated using the manufacturers' supplied fuel consumption data and fuel gas sulfur content. Particulate emissions include front-half and back-half particulate matter as measured by EPA Methods 5 and 202.

Maximum hourly emission rates for each compound are based on the type of fuel fired, the four ambient temperatures, and the three turbine load conditions (100%, 75%, and 50%) that represent the range of expected operating conditions. Annual emissions are based on the hourly emission rates for the worst-case loads during both natural gas and distillate oil-firing at an ambient temperature of 50°F (the inlet temperature for the majority of expected operating hours during the summer with inlet chilling). Annual emission estimates for NO_X, CO, VOC, SO_2, and PM/PM_{10} are calculated using a worst-case operating schedule of:

- 3,500 hours total operation per turbine, considering both natural gas and distillate oil;
- up to 3,500 hours of operation per year per turbine on natural gas; and
- 1,000 hours of operation per year per turbine on distillate oil.

The PSD permit will limit each turbine to 3,500 hours of operation per year.

The data used in this analysis is presented in Appendix B. Table 3-1 presents a summary of worst-case hourly emissions for the three combustion turbines. Table 3-2 presents a summary of estimates of annual potential emissions.

3.1.2 Non-Criteria Pollutants

Non-criteria pollutant emissions include PSD-regulated non-criteria pollutants and pollutants regulated by U.S. EPA under the National Emissions Standards for Hazardous Air Pollutants (NESHAPS). Estimates of Sulfuric Acid Mist and Lead emissions are included in tables 3-1 and 3-2, and have been prepared using the same calculation methodology as presented for PSD-regulated criteria pollutants.

An estimate of total Hazardous Air Pollutants emissions has also been performed. The calculation procedures used during the development of this application rely on process information developed for the proposed project, manufacturers' data and emission factors presented by U.S. EPA in the "Compilation of Air Pollution Emission Factor, AP-42". The summary presented below has been prepared for each source category identified previously. Detailed emission calculations for each emission source or source category are presented in Appendix B.

The primary emission sources at the MEC will be the three (3) combustion turbines. Hourly emissions from these units were calculated using the manufacturers' fuel feed rate (as MMBtu/hr). Emission factors were derived from one of two sources: 1) Section 3.1 of AP-42 or 2) information from the California Air Resources Board (CARB) CATEF database. The source of emission factors for each pollutant is identified in the Appendix B.

Maximum hourly emission rates for each compound were established using the highest hourly fuel feed rate (as MMBtu/hr, Higher Heating Value (HHV)) for the three load and the four ambient temperature conditions identified above. Annual emissions were based on the hourly fuel feed rate for 50°F, 100% load and 3,500 hours of operation with up to 1,000 hours of distillate oil operation. Table 3-3 presents a summary of emissions for the combustion turbines and the fuel heater.

Table 3-1 Hourly Emission Rate Summary for the MEC Combustion Turbines

Compound	Load (%)	Temperature (°F)			
		91	50	42	30
Emissions for One GE 7FA Turbine – Natural Gas Operation					
NO_x	100	53.5	59.6	60.4	61.6
	75	43.5	47.5	48.1	49.0
	50	34.4	37.7	38.1	38.7
CO	100	26.5	29.6	30.1	30.9
	75	21.8	23.5	23.8	24.3
	50	18.4	19.5	19.7	20.0
VOC	100	2.6	2.9	2.9	3.0
	75	2.2	2.3	2.3	2.3
	50	1.8	1.9	1.9	1.9
SO_2	100	9.5	10.6	10.7	10.9
	75	7.8	8.5	8.6	8.8
	50	6.2	6.8	6.9	7.0
H_2SO_4	100	1.5	1.6	1.6	1.7
	75	1.2	1.3	1.3	1.3
	50	0.9	1.0	1.1	1.1
PM/PM_{10}	100	18.0	18.0	18.0	18.0
	75	18.0	18.0	18.0	18.0
	50	18.0	18.0	18.0	18.0
Emissions for One GE 7FA Turbine – Distillate Oil Operation					
NO_x	100	289.6	321.0	325.5	332.1
	75	232.7	254.0	257.9	263.2
	50	181.9	199.2	201.5	204.6
CO	100	59.5	66.6	67.8	69.6
	75	50.7	56.8	57.5	58.5
	50	78.3	66.5	64.6	67.6
VOC	100	2.7	3.0	3.0	3.1
	75	2.2	2.3	2.3	2.4
	50	1.8	1.9	1.9	1.9
SO_2	100	90.3	100.2	101.6	103.6
	75	73.3	80.0	81.3	82.9
	50	57.9	63.4	64.2	65.1
H_2SO_4	100	13.8	15.3	15.6	15.9
	75	11.2	12.2	12.4	12.7
	50	8.9	9.7	9.8	10.0
PM	100	34.0	34.0	34.0	34.0
	75	34.0	34.0	34.0	34.0
	50	34.0	34.0	34.0	34.0
Pb	100	0.025	0.027	0.028	0.028
	75	0.020	0.022	0.022	0.023
	50	0.016	0.017	0.018	0.018

Table 3-2 Annual Emission Summary for the MEC Combustion Turbines

Turbine	NO_x	CO	VOC	SO_2	H_2SO_4	PM	PM_{10}	Pb
	Emissions for One Combustion Turbine (tons/year) [1]							
GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	39.5	0.013
	Emissions for All Combustion Turbines (tons/year) [1]							
3 x GE7FA	705.0	210.9	15.3	190.2	29.1	118.5	118.5	0.042

Notes:
[1] **Based on worst case hourly emission rate over the load range (50% - 100% base load), at the effective Annual Average Temperature of 50°F, and the following operation schedule:**
NG Annual Operation 2,500 hrs/year/turbine
Oil Annual Operation 1,000 hrs/year/turbine
Total Annual Operation 3,500 hrs/year/turbine

Table 3-3 Facility HAP Emission Summary

		3500 hrs Natural Gas	2500 hrs NG	1000 hrs Oil	2500 hrs NG & 1000 hrs Oil	CTGs All Cases	Fuel Heater	Facility Total
Total HAPs	Tpy	5.0	3.6	3.9	7.5	7.5	0.04	7.6
Max Single HAP	Tpy	2.6	1.8	2.4	2.4	2.6	4.01E-02	2.6
Max HAP Compound		Formaldehyde	Formaldehyde	Manganese	Formaldehyde	Formaldehyde	Hexane	
							Major Total HAPs	**No**
							Major Single HAP	**No**

3.2 Natural Gas Fuel Heater

Emission calculations for this unit are presented in Appendix B and summarized in Table 3-4 for criteria pollutants.

Table 3-1 Criteria Pollutant Emissions Summary for the Fuel Heater

Criteria Pollutants	Emission Rate - per Unit Hourly (Lbs/Hr)	Emission Rate - per Unit Annual (Tons/Year)
Nitrogen Oxides	1.3	2.3
Carbon Monoxide	1.2	2.1
Volatile Organic Carbon	0.78	1.37
Sulfur Oxides	0.07	0.13
Particulate	0.13	0.23

3.3 Fugitive Emissions

Breathing and working losses from the two, above-ground distillate oil storage tanks will constitute the main fugitive emissions from the MEC. The emission calculations were performed using Tanks 4.0, a U.S. EPA computer model, which considers tank characteristics, meteorological data, and annual material throughput to estimate emissions. A summary of the tanks' fugitive emissions is presented in Appendix B.

3.4 Total Project Criteria Pollutant Emission Summary

Tables 3-5 and 3-6 combine the analyses summarized on the preceding pages to establish the maximum emissions for the MEC. The annual emissions summaries reflect the maximum number of hours the turbines and fuel heater will operate. This will become a federally enforceable limitation specified in the PSD permit upon issuance.

Table 3-1 Project Hourly Emissions (lb/hr) Summary, Criteria Pollutants, MEC

Source Name	Source	NO_x	CO	VOC	SO_2	H_2SO_4	PM/PM_{10}	Pb
		Hourly Emission Rates (lb/hr)						
Combustion Turbine No. 1	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Combustion Turbine No. 2	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Combustion Turbine No. 3	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Fuel Heater No. 1		1.3	1.2	0.78	0.07		0.13	<0.01
Fuel Tanks				3.19				
Total		**997.6**	**236.1**	**13.3**	**310.9**	**47.7**	**102.1**	**<0.1**
Note: This table presents the maximum emission rate over the potential operating range (50% to 100% load and 30 to 91°F) for all operating conditions (Natural Gas or Oil).								

Table 3-2 Project Annual Emissions (tons/yr) Summary, Criteria Pollutants, MEC

Source Name	Source	NO_x	CO	VOC	SO_2	H_2SO_4	PM/PM_{10}	Pb
Combustion Turbine No. 1	GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Combustion Turbine No. 2	GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Combustion Turbine No. 3	GE 7FA	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Fuel Heater No. 1		2.3	2.1	1.37	0.13		0.23	<0.01
Fuel Tanks				1.3				
Total		**707.3**	**213.0**	**18.0**	**190.3**	**29.1**	**118.6**	**<0.1**
Note: This table presents the annual potential emissions based on maximum hourly emissions over 50% to 100% load range at the effective annual average temperature of 50 °F for all operating conditions (Natural Gas or Oil)								

Table 4-1 Project PTE (TPY) Criteria Pollutant Emissions Summary, Midway Energy Center

Source Name	NO_X	CO	VOC	SO_2	PM/PM_{10}	H_2SO_4	Pb
Combustion Turbine No. 1	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Combustion Turbine No. 2	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Combustion Turbine No. 3	235.0	70.3	5.1	63.4	9.7	39.5	0.014
Natural Gas Heater	2.3	2.1	1.4	0.13	0.23		<0.01
Distillate Oil Storage			1.3				
Total (Tons/year)	**707.3**	**213.0**	**18.0**	**190.3**	**29.1**	**118.6**	**<0.1**
PSD Major Source Threshold	**250**	**250**	**250**	**250**	**250**	**250**	**250**
PSD Significant Threshold	**40**	**100**	**40**	**40**	**25/15**	**7**	**0.6**

The following requirements are encompassed by PSD review.

- Compliance with any applicable emission limitation under the State Implementation Plan (SIP);
- Compliance with any applicable NSPS or NESHAPS;
- Application of Best Available Control Technology (BACT), as defined by the PSD rules, to emissions of NO_x, CO, SO_2, and PM/PM_{10} from all significant sources at the facility;
- A demonstration that the facility's potential emissions, and any emissions of regulated pollutants resulting from directly related growth of a residential, commercial or industrial nature, will neither cause nor contribute to a violation of the NAAQS or allowable PSD increments;
- An analysis of the impacts on local soils, vegetation and visibility resulting from emissions from the facility and emissions from directly related growth of a residential, commercial, or industrial nature;
- An evaluation of impacts on Visibility and Air Quality Related Values (AQRVs) in PSD Class I areas (if applicable); and
- At the discretion of FDEP, pre-construction and/or post-construction air quality monitoring for NO_x, CO, SO_2, and PM/PM_{10}.

Potentially applicable SIP limitations, NSPS and NESHAPs requirements are discussed below. A detailed BACT analysis is presented in Section 5. Contributions to the NAAQS and PSD increments are discussed in Section 6. Impacts on local soils, vegetation, and visibility are addressed in Section 7.

4.2 NSPS

The NSPS regulation that applies to combustion turbines is Subpart GG. This standard is applicable to stationary gas turbine units that have a heat input of greater than 10 MMBtu/hr. Under Subpart GG, units with a heat input at peak load greater than 100 MMBtu/hr and which supply more than one third of their electric generating capacity to a utility distribution system shall not emit NO_x in excess of:

$$STD = 0.0075(14.4/Y) + F$$

Where:

STD is the allowable NO_x emission, percent volume (corrected to 15 percent oxygen dry basis)

Y is rated heat rate at peak load, kilojoules/watt hour

F is NO_x emission allowance for fuel bound nitrogen, percent volume (for nitrogen content greater than 0.25 percent weight, F is 0.005 percent volume)

Applying the heat rate to the proposed General Electric 7FA turbine results in an applicable NSPS for NO_x emissions of approximately 110 ppmv on a dry basis, corrected to 15 percent oxygen, when firing natural gas. For distillate oil firing, the applicable NSPS limit is 102 ppm @ 15% oxygen. Both of these emission limits are well above the levels proposed as BACT (see Section 5).

Subpart GG also regulates the discharge of SO_2 by requiring compliance with one of the following two options:

- Limit SO_2 emissions to 0.015 percent or less by volume at 15 percent O_2 on a dry basis, or
- Limit the sulfur content of the fuel to 0.8 percent by weight or less.

The proposed project will readily meet the NSPS for SO_2 as both the proposed natural gas (2 grains/100 SCF) and distillate oil (<0.05 wt%) fuels will contain less than 0.8 percent sulfur content by weight.

Subpart Kb applies to each storage vessel, with some specified exceptions, with a capacity greater than or equal to 40 m^3 that is used to store volatile organic liquids for which construction commenced after July 23, 1984. Subpart Kb establishes storage vessel control equipment specifications, testing and associated procedures, and reporting and record keeping requirements. For this project, the distillate oil storage vessels will be subject to Subpart Kb based upon their maximum storage capacity. Due to the low vapor pressure of No. 2 distillate oil, these tanks will only be required to maintain records of the dimensions and maximum capacity of the tanks. No control requirements will apply.

4.3 NESHAPS

There is currently no NESHAPs for stationary gas turbines, although this is a source category scheduled for a determination of Maximum Achievable Control Technology (MACT) under 40 CFR Part 63. However, 40 CFR Part 63, Subpart B governs the construction or reconstruction of major sources of Hazardous Air Pollutants (HAPs) for which a NESHAP has not been promulgated. The rule requires new major sources of HAPs to install MACT for HAPs. MACT must be determined as a condition of pre-construction approval. A major source of HAPs is any stationary source that has the potential to emit 10 tons/year or more of a single HAP or 25 tons/year of combined HAPs.

Table 4-2 summarizes the project PTE for non-criteria pollutants. The project is not a major HAP source, and, therefore, 40 CFR Part 63 Subpart B does not apply.

Table 4-1 Project PTE Non-Criteria Pollutant Emissions Summary

Emission Source	HAP Emission Rate		Maximum HAP Emission Rate	
	Lbs/Hr	tons/year	Lbs/Hr	tons/year
Combustion Turbines[a]	8.1	7.5	5.0	2.6
Fuel Heater[b]	$2.5x10^{-2}$	0.043	$2.3x10^{-2}$	0.04
Total	8.1	7.6	5.0	2.6

(a) Formaldehyde is the single HAP that has the greatest contribution to the Total HAP Potential to Emit from the combustion turbines.
(b) Hexane is the single HAP that has the greatest contribution to the Total HAP Potential to Emit from the fuel heater.

4.4 Acid Rain

The proposed facility meets the definition of "utility unit" and will be an affected Phase II unit under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act. Title IV requirements for the proposed facility will be included in the Title V permit. Title IV requires requires that the facility hold calendar-year allowances for each ton of SO_2 that is emitted and conduct emissions monitoring for SO_2 and NO_x pursuant to the requirements in 40 CFR Parts 72, 73, and 75.

4.5 CAA Operating Permit Program

FDEP administers the CAA Operating Permit Program under Rule 62-213 which has been approved by EPA under 40 CFR Part 70. A new major source must submit a Title V operating permit application to FDEP within 180 days after commencing operation. The Title V application will incorporate applicable emission limitations, monitoring, record keeping and reporting requirements from the PSD construction permit.

4.6 State SIP Rules

In addition to the above regulations, the proposed facility is also subject to the Florida Air Pollution Control Regulations codified in Chapters 62-204 through 62-297 of the Florida Administrative Code (F.A.C.). The F.A.C. rules that are potentially applicable to the proposed project are as follows:

- General Pollutant Emission Limiting Standards

  Rule 62-296.320 limits visible emissions from any activity not specifically addressed by another Florida Regulation in Chapter 62-296. The general visible emission standard for stacks limits opacity to 20%. Compliance with the visible emission standard must be done in accordance with U.S. EPA Method 9. A companion rule limits visible emissions from fugitive sources by requiring sources to take reasonable precautions to prevent such emissions. Fugitive emissions may occur during construction of the facility. Wet suppression or similar techniques will be used to control emissions as necessary during construction activities

- General Construction Permitting Requirements

  Rule 62-210.310 requires that an air construction permit be obtained prior to commencing construction. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, and 62-210.300(1). This document includes the general information required by the FDEP for a construction permit application.

- Stack Height Policy

  Rule 62-210.550 specifies the stack height requirements and permissible dispersion techniques for permitting air emission sources. The facility will comply with the provisions of this regulation as presented in the air quality impact assessment (Section 6).

- Excess Emissions

  Rule 62-210.700 provides allowances for excess emissions for emission units that may occur during periods of startup, shutdown, malfunction, and load changes (non steady-state operations). Excess emissions from the combustion turbines are expected to occur during startup and shutdowns. The facility will apply best operational practices to minimize the duration of excess emissions.

- Annual Emissions Reporting

  Rule 62-210.370 requires Title V sources to submit an annual operating report that provides emissions information for the previous calendar year. Midway Development Company, LLC will submit to the FDEP annual emissions reports by March 1 of the following year.

5.0 CONTROL TECHNOLOGY EVALUATION

5.1 Introduction

In accordance with PSD requirements, FDEP requires the application of Best Available Control Technology (BACT) for the control of each regulated pollutant emitted in significant quantities from a new major stationary source located in an attainment area for that pollutant. The proposed Midway Energy Center's combustion turbines must demonstrate the application of BACT for oxides of nitrogen (NO_X), carbon monoxide (CO), fine particulate (PM_{10}), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4).

5.1.1 Top-Down BACT Approach

The BACT requirements are intended to ensure that a proposed facility or major modification will incorporate air pollution control systems that reflect the latest demonstrated practical techniques for each particular emission unit, and will not result in the exceedance of a National Ambient Air Quality Standard (NAAQS), PSD Increment, or other standards imposed at the state level. The BACT evaluation requires the documentation of performance levels achievable for each air pollution control technology applicable to the Midway Energy Center.

EPA and FDEP recommend a "top-down" approach when evaluating available air pollution control technologies. This approach to BACT involves determining the most stringent control technique available, known as the Lowest Achievable Emission Rate (LAER) for a similar or identical emission source. If it can be shown that the LAER is technically, environmentally, or economically impractical on a case-by-case basis for the proposed emission source, then the next most stringent level of control is similarly evaluated. This process continues until a control technology and associated emission level is determined that cannot be eliminated by any technical, environmental, or economic objections. The top-down BACT evaluation process is described in U.S. EPA's draft document "New Source Review Workshop Manual (U.S. EPA, October 1990). The five steps involved in a top-down BACT evaluation are:

- Identify options with practical potential for control of the regulated pollutant under evaluation;
- Eliminate technically infeasible or unavailable technology options;
- Rank the remaining control technologies by control effectiveness;
- Evaluate the most effective controls and document the results; if the top option is not selected as BACT, evaluate the next most effective control option; and

- Select BACT, which will be the most effective practical option not rejected based on prohibitive energy, environmental, or economic impacts.

ENSR employed the "top-down" approach in evaluating available pollution controls for the Midway Energy Center.

5.1.2 Cost Determination Methodology

Economic analyses of certain BACT alternatives were performed to compare capital and annual control costs in terms of cost-effectiveness (i.e., dollars per ton of pollutant removed). Capital costs include the initial cost of components intrinsic to the complete control system. High-temperature SCR, for example, would include catalyst modules, transition piece, support frame, ammonia storage tanks, ammonia dilution air and injection system, piping, flue gas attemperation system, provisions for catalyst cleaning and removal, instrumentation, and installation costs. Annual operating costs consist of the financial efficiency losses, parasitic loads, and revenue loss from operation of the control system and include overhead, maintenance, labor, raw materials, and utilities.

5.1.3 Capital Costs

The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation costs. This technique is a modified version of the "Lang Method," whereby installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA guidance manual (OAQPS Control Cost Manual) on estimating control technology costs (U.S. EPA, January 1996). The estimation factors used to calculate total capital costs are shown in Table 5-1.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for continuous operation of the device. These may include such items as reagent storage tanks, supply piping, turbine outlet transition piece, catalyst removal crane, spare parts and catalyst, and air dilution system. Auxiliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage based on the average requirements of typical systems and their auxiliary equipment (U.S. EPA, January 1996). In this BACT evaluation, basic equipment costs were obtained from data provided by qualified vendors (see Appendix C). Instrumentation, which is usually not included in the basic equipment cost, is estimated at 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor including site preparation, foundations, structural steel, insulation erection, piping, electrical, painting, and enclosure.

Table 5-1 Capital Cost Estimation Factors

Item	Basis
Direct Costs	
Purchased Equipment Cost	
Equipment cost + auxiliaries[1]	A
Instrumentation	0.10 x A
Sales taxes	0.06 x A
Freight	0.05 x A
Total Purchased equipment cost, (PEC)	B = 1.21 x A
Direct installation costs	
Foundations and supports	0.08 x B
Handling and erection	0.14 x B
Electrical	0.04 x B
Piping	0.02 x B
Insulation for ductwork	0.01 x B
Painting	0.01 x B
Total direct installation cost	0.30 x B
Site Preparation, SP	As Required
Buildings, Bldg	As Required,
Total Direct Cost, DC	1.30B + SP + Bldg.
Indirect Costs (installation)	
Engineering	0.10 x B
Construction and field expenses	0.05 x B
Contractor fees	0.10 x B
Start-up	0.02 x B
Performance test	0.01 x B
Contingencies	Variable
Other[2]	As Required
Interest during construction[3]	DC x i x n
Total Indirect Cost, IC	0.28B + Interest + Contingencies
Total Capital Investment (TCI) = DC + IC	**1.58B+ SP + Bldg. + Interest + Contingencies**

[1]Auxilliaries include ammonia tank, transition piece, crane, spare catalyst, dilution air system, etc.

[2]Emergency Response Plan (ERP), Spill Prevention Countermeasure and Control (SPCC), Risk Management Plan (RMP), etc.

[3]Simple Interest During Construction, i = interest rate; n = interest period

Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, contingencies, and additional permits and licensing costs.

Direct installation costs are expressed as a function of the purchased equipment cost, based on average installation requirements of typical systems. Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment startup and performance testing, contingencies, and working capital.

5.1.3.1 Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include electricity losses, labor, maintenance, replacement parts, raw materials, and utilities. Indirect operating costs include overhead, taxes, insurance, general administration, contingencies, and capital charges. Annualized cost factors used to estimate total annualized cost are listed in Table 5-2, and are consistent with the EPA guidance on estimating control technology costs (U.S. EPA, January 1996).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of total direct cost (TDC). Replacement part costs, such as the cost to replace aged or failed catalyst, have been included where appropriate. Reagent and utility costs are based upon estimated annual consumption and the unit costs are summarized in Table 5-2. The presence of a catalyst bed would increase turbine back pressure resulting in heat rate (efficiency) losses to the system. This is reflected in the economic analysis as the value of lost power output and is based on turbine vendor estimates. Based on the experience of other facilities contacted, the catalyst for a catalytic oxidation or reduction technology is assumed in this analysis to require replacement every 3 years due to failure or aging. The cost of replacement catalyst was provided by catalyst vendors which was then annualized over 3 years.

With the exception of overhead and contingency, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where "i" is the annual interest rate and "n" is the equipment economic life (years). An emission control system's economic life is typically 10 to 20 years (U.S. EPA, January 1996). In this analysis, a 10-year equipment economic life (typical length of financing) was used. The average interest rate is assumed to be 7 percent (U.S. EPA, January 1996). CRF is therefore calculated to be 0.142.

Table 5-1 Annualized Cost Factors

Item	Cost Factor	Unit Cost
DIRECT ANNUAL COSTS, DC		
Electricity		
Heat rate loss due to pressure drop	0.1% output loss for every inch of delta P	$0.10/kW-hr
Dilution air fan electricity	Dilution air to prevent catalyst deterioration	$0.10/kW-hr
Operating labor		
SCR Labor Req.	0.5 hr/shift	$30.00/hr
Supervisor	15% Operating Labor	NA
Ammonia Delivery Requirement	24 hr/yr (3 deliveries per year)	
Ammonia Recordkeeping and Reporting	40 hr/yr (1 week of reporting)	
Catalyst Cleaning	80 hr/yr (2 workers x 40 hr/yr)	
Maintenance		
Catalyst Replacement Labor	8 workers, 40 hr, every 3 years	$30.00/hr
Catalyst System Maintenance Labor Req.	0.5 hr/shift	$30.00/hr
Ammonia System Maintenance Labor Req.	1 hr/day, 365 day/yr	$30.00/hr
Material	100% Maintenance Labor	NA
Ammonia	Ammonia	$315 per ton
Process Air	350 scf/lb NH_3	$0.20 per thousand scf
Catalyst	100% replaced/3 years plus disposal	
INDIRECT ANNUAL COSTS, IC		
Overhead	60% labor + materials	
Administrative Charges	2% TCI	
Property Taxes	1% TCI	
Insurance	1% TCI	
Capital Recovery	CRF x TCI	
Contingency for new technology	NA	0-20% DC
Total Annual Cost (TAC) ($)		Sum of Annual Costs
Total Pollutant Controlled (ton/yr)		As Calculated
COST EFFECTIVENESS ($/ton)		**TAC/tpy controlled**

5.1.3.2 Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the technology and its annual pollutant emission reduction. Cost-effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical tons of pollutant that would be removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on comparing the uncontrolled emission rate with the achievable emission rate based on information contained in issued permits, EPA literature and vendors of the control equipment.

5.2 Previous BACT/LAER Determinations for Simple-Cycle Combustion Turbines

The proposed Midway Energy Center is a "Simple-Cycle" electrical peaking facility. A Simple-Cycle peaking project is fundamentally different than the more common "Combined-Cycle" base load systems that represent the majority of listings in EPA's RACT/BACT/LAER Clearinghouse. The differences in these two types of power generation technology are reviewed in Sections 5.2.1 and 5.2.2.

In a deregulated market for electricity, new generation capacity will be built only when there is a sufficient customer demand for that capacity. The electric output of any new capacity must be sold (and must therefore be priced competitively with existing capacity) in order to earn a Return On Investment (ROI) commensurate with the financial risk of building the powerplant. A market need exists in Florida for peak load power and, therefore, the Midway Energy Center is being developed to serve that specific peak power market.

5.2.1 Base Load Power (Combined-Cycle)

Regional power demand is variable from night to day, from hot summer days (which reflect air-conditioning loads) to cold winter days, from workdays to weekends, etc. However,, there is a certain constant level of electrical demand that is always present, referred to as "base load". The nature of generation capacity built to provide base load power is that it is designed to maximize annual operation at a constant or "base" load at the lowest operating cost possible. Since fuel cost is the single biggest component of the cost to produce power, competitive base load generators must be designed to operate at the highest possible fuel efficiency and to produce their rated output continuously at maximum availability. The Combined-Cycle plant meets these criteria.

A rotating combustion turbine, driving a generator via a connecting shaft represents a thermodynamic cycle known as the Brayton Cycle; this arrangement is also referred to as "Simple-Cycle". In a Simple-Cycle turbine, air and products of combustion exiting the turbine are exhausted to the atmosphere at temperatures of about 1,100°F, which represents a substantial energy loss.

A boiler that produces steam which is then used to generate electricity in a steam turbine/generator is referred to as the Rankine Cycle. In this thermodynamic cycle, energy lost as waste heat from a surface condenser is typically rejected to cooling towers or a large body of cooling water. Traditional central utility powerplants are of this design. Condensation of steam with cooling water also represents a substantial energy loss.

Each of these cycles is significantly limited in achievable "heat rate" (the amount of electricity that can be generated per Btu of fuel input) because in each case substantial amounts of heat energy are wasted. When a Brayton Cycle turbine is connected in series with a Rankine Cycle waste heat boiler, a much lower heat rate (higher thermal efficiency) can be achieved. This is referred to as "Combined-Cycle". While a Combined-Cycle powerplant exhibits much higher initial capital cost, these costs can be quickly recovered in greater fuel efficiency in a base load plant which operates around the clock at near full capacity. The Combined-Cycle powerplant therefore, by definition incorporates a waste heat boiler or Heat Recovery Steam Generator (HRSG) and steam turbine generator. The HRSG recovers waste heat exiting the turbine at about 1,100°F and exhausts at about 220°F. With an HRSG as a component of the above-mentioned combined cycle, a temperature "window" exists which has allowed catalytic pollution control technology to be widely applied to new Combined-Cycle powerplants. This post combustion control technology is responsible for the very low (i.e. 2.5 – 3.5 ppm) NO_x emission rates reported for recent Combined-Cycle units in EPA's RACT/BACT/LAER Clearinghouse.

5.2.2 Peaking Power (Simple-Cycle)

Once base load demand is satisfied, a need still exists to supply additional power at certain times when base load requirements are exceeded by the short term peak power demand. Average peak power prices tend to be higher than for base load power. However, peaking units operate substantially fewer hours per year than base load units. The economics of providing peak power favor lower initial capital cost (there are fewer operating hours per year in which to earn back the capital investment) and are less sensitive to optimization of heat rate. Most importantly, peak power must be able to come on-and off-line very quickly and, in some cases is designed to "follow" electrical demand.

Simple-Cycle is the only combustion turbine configuration that meets this requirement. For example, a common application of combustion turbine engines that do not employ an HRSG is for aircraft applications. Helicopters and turbo-prop commuter aircraft utilize combustion turbine engines that drive a mechanical propeller shaft. These engines are routinely shut down during boarding, started up for taxiing and accelerated to full output during takeoff, all within a matter of minutes. Combined-Cycle units, on the other hand require a cold start-up schedule, measured in hours, to be brought from ambient temperature to full load. This is because the heat transfer surfaces and catalyst beds within the HRSG are sensitive to "thermal shock". Ceramics and steel that are heated too quickly are subjected to uneven thermal expansion and will warp, crack and/or fail if not allowed sufficient time to be brought to temperature more gradually. Start up schedules that are designed to protect back end equipment typically involve several steps of "ramping" and "soaking." This soaking time is required to protect the back-end equipment from failure due to thermal stress limits the feasibility of HRSG's and catalysts for use in quick response peaking applications. On any given day, the demand for peak power may only last three to four hours. By the time a Combined-Cycle unit has been warmed up to full operating load, the market demand to produce the peak power may be over.

5.2.3 BACT Determinations for Simple-Cycle Combustion Turbines

When reviewing emission levels that have been permitted as BACT or LAER in EPA's database, it is important to distinguish between Simple-Cycle and Combined-Cycle source categories, although the Clearinghouse listings are not always clearly categorized. It should also be noted that natural gas pipeline compressor engines are mechanical compressor drive applications; while they do not employ HRSG's, these sources are much smaller units (2-5 MW equivalent) and do not cycle on and off to meet demand as quickly or as frequently as power generation peaking turbines do. Compressor station turbines are not representative of a large scale peaking powerplant application.

A list of previous BACT/LAER determinations for all types of combustion turbines is presented in Appendix C. These tables are compiled from EPA's RACT/BACT/LAER Clearinghouse and from ENSR's database of combustion turbine projects. The RACT/BACT/LAER Clearinghouse keeps a listing of RACT/BACT/LAER determinations by governmental agencies for many types of air emission sources, and is available in hard copy or through a computerized database. While the RACT/BACT/LAER Clearinghouse covers information from the past 10 to 12 years, only the more recent decisions (1993-present) have been included here.

It should be noted that all listings in California represent LAER, even though they are often listed as BACT (BACT and LAER in California are identical). LAER is a much more stringent requirement than BACT, and involves application of control technology regardless of cost. This is not the case for the proposed Midway Energy Center peaking project. ENSR also reviewed the California Air Pollution Control Officers Association (CAPCOA) on-line BACT Clearinghouse and found the only LAER decisions listed after 1993 to be for the same facilities. ENSR also called regulators in Indiana, California and several other states to determine levels of control which are being proposed or required of the most recent projects. Finally, ENSR contacted the turbine and catalyst manufacturers. Our search identified several Simple Cycle projects not listed in EPA's BACT/RACT/LAER Clearinghouse which have been permitted recently in California with lower emission limits and which employ add-on control technology.

5.2.4 Combustion Turbine Fuel Use

As part of its application, the Midway Energy Facility is requesting increased flexibility regarding the ability to burn 1,000 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission ("FGT") pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the

FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 Bcf/day during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMbtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for greater oil burning flexibility is necessitated by near term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and oil will be used only to the extent transmission capacity constraints on FGT preclude the delivery of natural gas to the site

As the proposed facility is intended to provide peak power which will typically occur during periods when natural gas demand will be high, the ability to operate using distillate oil as an alternative fuel is necessary to provide system reliability. As the facility is being proposed as a duel fuel facility the control technology analysis has been performed assuming the maximum amount of oil consumption, when determining potential emissions.

5.3 BACT for Nitrogen Oxides (NO_x)

5.3.1 Formation

NO_x is primarily formed in combustion processes in two ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen (EPA 1996); therefore, NO_x emissions from combustion turbines when burning natural gas originate as thermal NO_x. The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. Liquid fuels such as No. 2 distillate contain significant levels of fuel bound nitrogen. The combustion of liquid fuels results in inherently higher emissions of NO_x due to the combination of both thermal NO_x and fuel NO_x which forms when fuel nitrogen is exposed to high flame temperatures in the presence of free oxygen.

5.3.2 Front – End Control

"Front-end" NO_x control techniques are aimed at controlling one or more of these variables. The primary front-end combustion controls for gas turbines include water or steam injection and dry low NO_x combustors. The addition of an inert diluent such as water or steam into the high temperature region of the flame controls NO_x formation by quenching peak flame temperature, which reduces emissions of both thermal and fuel NO_x. This technique can be operationally very hard on the turbine and combustors due to vibration and flame instability. Recent advances in the state-of-the-art have resulted in dry low NO_x combustors for gas firing that limit peak flame temperature and excess oxygen with lean, pre-mix flames, that can achieve equal or better NO_x control without the addition of water or steam. Catalytic combustion is an emerging front-end technology for gas-only fired turbines using an oxidation catalyst within the combustor to produce a lower temperature flame and hence, low NO_x. Catalytic combustion is potentially capable of reducing natural gas-fired turbine NO_x emissions to 2-5 ppmv, but is not applicable to oil-fired or dual fuel applications. Catalytica, Inc. was the first company to commercially develop catalytic combustion controls for certain (mostly smaller) turbine engines and markets them under the name XONON™. Catalytic combustion technology is not yet commercially available for 170 MW F-Class turbines, and is not a technically feasible technology for dual fuel operation. Therefore, XONON™ does not represent an available control option for the Midway Energy Facility.

5.3.3 Back – End Control

Other control methods, known as "back-end" controls, remove NO_x from the exhaust gas stream once NO_x has been formed. Selective Catalytic Reduction (SCR) using ammonia as a reagent represents the state-of-the-art for back end gas turbine NO_x removal from base load, combined cycle turbines. Conventional SCR is not applicable to simple cycle turbines due to materials temperature limitations which preclude its application in high temperature simple cycle turbine exhaust. A high temperature SCR technology has recently been introduced for potential application to simple-cycle turbines but with limited success to date. In particular, high temperature SCR has been applied at a few small peaking turbines in California.

Selective catalytic reduction (SCR) is a process which involves post-combustion removal of NO_x from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \qquad (2)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (3)$$

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \qquad (4)$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \qquad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling", design of the NH_3 injection system, and high NH_3 slip. There are only four U.S. installations of this technology on simple cycle peaking turbines (Booth, 1999), and none of these has a long-term history of success. Three of these applications are on relatively small natural gas-only peaking turbines that have limited hours of operation to date. While these units have reported some initial problems, U.S. EPA has indicated that they consider high temperature SCR to be "demonstrated in practice" for natural gas fired peaking turbines.

One of the high temperature SCR installations is the Puerto Rico Electric Power Authority (PREPA) Cambalache Electric Generating Facility, located in Puerto Rico. This project consists of three (3) ABB GT 11N1 combustion turbines operated in simple cycle mode, using distillate oil. The original permit issued for these turbines required the use of SCR to achieve NO_x emissions of 10 ppm, with a limit of 10 ppm on ammonia emissions. This plant has been operating since 1997 with very poor results for the operation of the SCR system. This project has not been able to operate for any extended period of time while staying within the NO_x and NH_3 limits and has been issued a Notice of Violation by EPA for exceedances of both NO_x and NH_3. Several attempts have been made to regenerate, or clean the catalyst, with no significant improvement in the performance of the system. EPA has been working with PREPA to solve the difficulties that have resulted from installation of hot SCR at the Cambalache facility, in January of 2000, US EPA Region 2 issued a press release stating: "...on oil-fired turbines, SCR cannot consistently achieve the expected reductions in nitrogen oxide emissions. As a result, EPA is removing the SCR requirement..." (US EPA Region 2 Press Release, the complete press release is included in Appendix C).

As a result of this experience, Englehard is no longer offering this technology for oil-fired turbine applications. The Midway Energy Center Facility is a dual fuel peaking project that must have the flexibility to burn liquid fuel as backup to natural gas. High temperature SCR is not technically feasible for oil fired combustion turbines, and has not been demonstrated in practice on dual fuel peaking turbines. However, at the request of FDEP, a cost effectiveness calculation for high temperature SCR has been performed for the proposed turbines, disregarding costs associated with a control technology that would represent a first of a kind application. Also not included in this cost evaluation is the impact of the catalyst on the operating strategies that would require an extended startup sequence to protect the catalyst bed. The results of this analysis clearly indicate that high temperature SCR would not be cost effective. As shown in Appendix C, high temperature SCR controlling NO_x emissions to the LAER levels of 3.5 ppmvd @ 15% O_2 while firing natural gas and 16 ppmvd @ 15% O_2 while firing distillate oil would cost over $15,000/ton of NO_x removed. If the lost revenue to the fundamental changes in operation were incorporated into this analysis, primarily resulting from extended startup duration, the overall cost effectiveness would exceed $20,000/ton.

On August 4, 2000 US EPA issued draft combustion turbine BACT guidance for public review (Appendix C). While this draft document is only being circulated for comment and does not represent official EPA policy, it does contain useful information relative to the application of SCR to GE's 9 ppm DLN generation turbines. Note that the discussion by EPA identifies several negative collateral environmental impacts associated with application of SCR to 9 ppm base load, combined cycle turbines. These negative impacts are exacerbated for simple cycle peaking applications, as discussed below:

Peaking turbines start and stop quickly, and may only operate a few hours at a time. Until the SCR catalyst reaches temperature, ammonia (NH_3) may not be introduced (resulting in less relative NO_x control), or if it is introduced will result in elevated NH_3 slip. Since a significant portion of a peaking turbines operation is spent warming up, following load (transient operation) and shutting down, high temperature SCR would control less NO_x and emit more slip when dispatched than a base load turbine would.

To reduce NO_x from 9 ppm to 3.5 ppm on units that will operate less than 3,500 hours per year will result in much lower NO_x reduction benefits than for EPA's analysis of combined cycle units. It should be noted that 3,500 hours represents an upper limit on operation for permitting, but in actual operation peaking units may in fact be normally dispatched less than 1,000 hours per year.

Peaking turbines may be thought of as similar to emergency generators. When they are called upon to operate, it is to fill a temporary shortfall in generation capability. SCR systems rob electrical output (due to backpressure) precisely when that output is most needed (peak demand).

High temperature SCR is therefore, not technically feasible, would exhibit overriding negative collateral environmental impacts, and in any event would not be cost effective for application to the dual fuel Midway Energy Facility.

An emerging technology called $SCONO_X^{TM}$, which also uses a back-end catalyst but operates without ammonia, has shown promise during initial trials on a 23 MW turbine installation in California, and a 5 MW turbine in Massachusetts. $SCONO_X^{TM}$ is an emerging technology that offers the promise of reducing NO_x concentrations to approximately 2-3.5 ppmv for smaller turbine applications. Despite this promise, $SCONO_X^{TM}$ is still very new and only operates effectively over a narrow 300°F to 500°F temperature range. According to the ABB Alstom internet website, ($SCONO_X^{TM}$ is marketed for applications greater than 100MW by Alstom). $SCONO_X^{TM}$ is not available for application to simple cycle combustion turbines. The planned Midway Energy Facility turbines will have exhaust temperatures of 1100 to 1200°F therefore, $SCONO_X^{TM}$ is not a technically feasible control option for the proposed Midway Energy Facility.

Two other back-end catalytic reduction technologies, Selective Non-Catalytic Reduction (SNCR) and Nonselective Catalytic Reduction (NSCR), have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1300 to 2100°F, with an optimum operating temperature zone between 1600 and 1900°F (Fuel Tech, 1991). Simple-cycle combustion turbines have exhaust temperatures of approximately 1100°F. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the Midway Energy Facility turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible and inappropriate for the Midway Energy Facility turbines.

The technologies that may represent effective controls for the proposed dual fuel peaking turbines are ranked and evaluated in the following sections. It should be stressed that levels of control being evaluated as BACT must be applicable to a dual fuel peaking power plant that will employ simple-cycle turbines for limited annual hours of operation.

5.3.4 Gas Turbines - Ranking of Available Control Techniques

Emission levels and control technologies for all types of combustion turbines have been identified and ranked for application to simple cycle dual fuel peaking turbines (see Table 5-3). Dry low NO_x controls (as described in EPA's draft turbine policy) represent the most stringent control technology for the planned turbine installation. Environmental, technical, and economic analyses of various DLN emissions levels are reviewed in the remaining BACT evaluation sections.

Table 5-1 Ranking of NO_x Control Technologies for a Dual Fuel Simple-Cycle Peaking Turbine

Control Technology	Typical Control Efficiency Range (% Removal)	Typical Emission Level[(a)] (ppmv)	Technically Feasible on Dual Fuel Simple-Cycle Gas Turbine
SCONOx™	90-95	2-3.5	No
XONON™ flameless combustion	80-90	2-5	No
NSCR	30-70	9-25	No
SNCR	30-70	9-25	No
Conventional (low temperature) SCR plus water injection or SCR plus low-NO_x combustor	50-95	2-6	No
High Temperature SCR plus water/steam injection or advanced low-NO_x combustor	50-95	5-12	No
Dry low-NO_x Combustor	30-70	9-25 (gas)	Yes
Water/steam injection Combustor	30-70	25-42 (oil)	Yes

(a) **Values represent long-term emission rates.**

A search of the U.S. EPA RACT/BACT/LAER Clearinghouse was completed to assist in the identification of potential control alternatives. The RACT/BACT/LAER Clearinghouse has become out of date due to the rapid pace of power projects being permitted due to deregulation of the power generation industry.

In order to determine the specific NO_x emission levels being permitted for recent peaking turbine projects, ENSR also reviewed an informal list of recent projects obtained from US EPA. The simple cycle turbines subject to BACT in EPA's list are provided in Table 5-4. It can be seen from this list that many simple cycle turbines are being permitted with dry low NO_x combustors in the range of 9–15 ppm. These emission levels are discussed in the following sections as candidates for BACT from the Midway Energy Center.

Table 5-2 US EPA National Simple Cycle PSD Turbine Projects

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 4	AL	Applic. Under review	South Eastern Energy Corp.	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		For NOx and CO: SC w/GE or SC w/SW501F or CC (either)
REGION 4	AL	applic. under review	Tenaska Alabama II Generating Station	3	3	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 720 FO	15/42 ppm (SC); 4/42 ppm (CC)	DLN/WI; SCR/WI		
REGION 4	FL	10-99	Polk Power (TECO)	2		GE 7 FA (165 MW)	NG; FO	SC	5,130; 750 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	11-99	Oleander Power	5		GE 7FA (190 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	10-99	Hardee Power Partners (TECO)	1		GE 7EA (75 MW)	NG; FO	SC	8,760; 876 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	12-99	Reliant Energy Osceola	3		GE 7FA (170 MW)	NG; FO	SC	3,000; 2,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	12-99	Florida Power Corp., Intercession City	3		GE 7EA (87 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	10-99	Jacksonville Electric Authority - Brandy Branch	3		GE 7FA (170 MW)	NG; FO	SC	4,000; 800 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	1-00	IPS Avon Park - Shady Hills	3		GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	draft permit	Palmetto Power	3		SW 501F (180 MW)	NG	SC	3,750	15 ppm	DLN		
REGION 4	FL	applic. under review	Granite Power Partners	3		(180 MW)	NG; FO	SC	3,000; 500 FO	10.5/15/15/25 ppm NG; 42 ppm FO	DLN		4 vendor options: GE 7FA/SW 501F/SW 501D5A/ABB GT-24
REGION 4	FL	draft permit	IPS Avon Park Corp. - DeSoto Power Project	3		GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	applic. under review	Florida Power & Light - Martin Power Plant	2		GE 7FA (170 MW)	NG; FO	SC	3,390; 500 FO	10.5 ppm NG (15 ppm HPM); 42 ppm FO	DLN; WI		HPM = High Power Mode (power augmentation)
REGION 4	GA	12-98	Tenaska Georgia Partners, L.P.	6		GE 7FA (160 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	GA	6-99	West Georgia Generating; Thomaston	4		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		
REGION 4	GA	10-99	Heard County Power	3		SW 501FD (170 MW)	NG	SC	4,000	15 ppm	DLN		
REGION 4	GA	8-99	Georgia Power, Jackson County	16		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		
REGION 4	KY	applic. under review	Duke Energy - Marshall Co.	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr	

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 4	FL	7-10-98	City of Lakeland, McIntosh Power Plant	1		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		Power Augmentation
REGION 4	MS	applic. under review	Duke Energy Southaven	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI		
REGION 4	MS	applic. under review	Warren Power LLC	4		GE 7EA (80 MW)	NG	SC	2,000	9 ppm	DLN		
REGION 4	NC	11-99	Carolina Power & Light, Richmond Co.	7		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		
REGION 4	NC	11-99	Carolina Power & Light, Rowan Co.	5		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		
REGION 4	NC	6-99	Rockingham Power (Dynegy)	5		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		
REGION 4	NC	applic. under review	Butler-Warner Generation Plant	2		GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	SC	draft permit	Santee Cooper, Rainey Generating Station	4		GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	SC	12-99	Broad River Energy (SkyGen)	3		GE 7FA (171 MW)	NG, FO	SC	3,000; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	TN	7-99	TVA, Johnsonville Fossil Plant	4		GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI ?		10% NG base mode, 10% NG peaking, 10% FO base
REGION 4	TN	7-99	TVA, Gallatin Fossil Plant	4		GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI ?		10% NG base mode, 10% NG peaking, 10% FO base
REGION 4	TN	applic. under review	TVA, Lagoon Creek Plant	16		GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI ?	30;15 day	10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
REGION 5	IL	Dec-98	Peoples Gas, McDonell Energy	4		170 MW	NG, ethane	SC	1,500	15 ppm	DLN	1-hr	BACT; operational
REGION 5	IL	Sep-99	Enron, Des Plaines Green Land	8	0	83 MW	NG	SC	3,250	9/12/15 ppm	DLN	an/mo/hr	BACT; Ox Cat rejected at $6800/ton
REGION 5	IL	Jan-00	Enron, Kendall New Century	8	0	83 MW	NG	SC	3,300	9/12/15 ppm	DLN	an/mo/hr	BACT; Ox Cat rejected at $6700/ton
REGION 5	IL	Jan-00	LS Power, Nelson Project	4		220 MW	NG; FO	SC	2,549 total, 2,000 each	25/15	DLN	1-hr	Synth Minor; minor until test under 15 ppm
REGION 5	IL	draft permit	Duke Energy	8	0	83 MW	NG; FO	SC	2,000; 500 FO	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 5	IN	Jul-99	Vermillion Generating Station	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI	an	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
REGION 5	IN	applic. under review	DeSoto Generating Station	8		GE 7EA (80 MW)	NG	SC	2,500	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	BACT
REGION 5	MN	draft permit	Lakefield Junction	6		GE model PG7121EA (92 MW)	NG; FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI	3-hr	PSD; SCR rejected @ $11,500/ton; Ox Cat rejected at $3000/ton
REGION 5	OH	Jul-99	Duke Energy Madison LLC	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.)	BACT; SCR rejected at $19,000/ton; Ox Cat rejected at $9000/ton
REGION 5	WI	Jan-99	RockGen Energy	3		GE 7FA (175 MW)	NG; FO	SC	3,800 Total, 800 FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst; 1 hr	BACT; SCR not chosen; cost $23,018/ton; Ox Cat rejected at $15 K/ton
REGION 5	WI	Feb-99	Manitowoc Public Utility	1		GE Frame 5 (24.5 MW)	NG; FO	SC	2,328 Total	77 ppm NG; 77 ppm FO	WI	1-hr	BACT
REGION 5	WI	Feb-99	Southern Energy	2		GE 7FA (180 MW)	NG; FO	SC	8,760 Total, 699 FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst; 1 hr	BACT; Ox Cat rejected at $14 K/ton
REGION 5	WI	Jul-99	Wisconsin Public Service	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	BACT; SCR rejected at $13,866/ton; Ox Cat rejected at $6053/ton incremental cost
REGION 5	WI	draft permit	Wisconsin Electric	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	BACT; SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost
REGION 7	KS	draft permit	Western Resources	3		2 - 100 MW, 1 - 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
REGION 7	MO	1-96	Kansas City Power & Light - Jackson	1		(200 MW)	NG	SC					
REGION 7	MO	draft permit	AECI - Nodaway	2		(100 MW)	NG	SC		25 ppm	DLN		
REGION 7	MO	applic. under review	Kansas City Power & Light - Jackson	2		(75 MW)	NG	SC		9 ppm	DLN		
REGION 7	MO	applic. under review	Duke Energy - Audrain	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 1-hr avg.); 42 ppm FO	DLN; WI		
REGION 7	MO	applic. under review	Duke Energy - Bollinger	8		GE 7EA (80 MW)	NG	SC	2,500	12 ppm (15 ppm 1-hr avg.)	DLN		
REGION 7	NE	7-99	Omaha Public Power	4		(25 MW)	NG; FO	SC		25 ppm NG; 42 ppm FO	WI		
REGION 7	NE	6-99	Lincoln Electric System	1		(90 MW)	NG; FO	SC		25 ppm NG; 42 ppm FO	DLN; WI		
REGION 8	CO	final 4/99	Colorado Springs Utilities/Nixon (66 MW)	2		GE PG6541(B)	NG	SC	8,660 (both CTs)	15 ppm	DLN	1-hr	did not trigger BACT for CO

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 8	CO	final 8/99	Fulton Cogeneration /Manchief (284 MW)	2		SW V84.3A1	NG	SC	8,760	15 ppm	DLN	1-hr	
REGION 8	CO	applic. 11/99	KN Energy/Front Range Energy Associates - Ft. Lupton (160 MW)	4		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
REGION 8	CO	applic. 3/00	Platte River Power Authority/Rawhide (82 MW)	1		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
REGION 8	CO	draft permit 5/00	Public Service Co. of Colo./Ft. St. Vrain Unit 4 (242 MW)	1	1	GE PG7241 (FA)	NG	SC/CC	8,760	4 ppm (CC); 9 ppm (SC)	DLN+SCR (CC); DLN (SC)	24-hr	plan startup 6/2001;
REGION 8	CO	applic. 11/99	Front Range Power Project/Ray Nixon Sta., Fountain, CO (480 MW)	2	2	GE Frame 7	NG	SC/CC	8,760	9 ppm/16 ppm w/ DB	DLN		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
REGION 8	SD	applic. 11/99	Black Hills Power & Light/Lange CT Facility (80 MW)	2		GE LM6000PD	NG	SC	8,760	25ppm (proposed)	DLN	24-hr	Characterized as peaking plant, but not restricted in operating hours
REGION 8	WY	final 3/00	Black HIlls Power & Light/Niel Simpson II (80 MW)	2		GE LM6000PD	NG	SC	8,760	25 ppm	DLN	24-hr	Region provided written comment disagreeing w/ NOx BACT determination; characterized as peaking plant, bur not restricted in operating hours
REGION 8	WY	final 2/98	Two Elk Generation Partners (33 MW turbine)	1		GE LM5000	NG	SC	8,760	25 ppm	DLN	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

The GE 7FA turbines proposed for the Midway Energy Facility will employ General Electric's state-of-the-art 9 ppm NO_x Dry low-NO_x (DLN) Combustion technology. EPA acknowledges that 9 ppm is the lowest Dry low- NO_x emission level that has been demonstrated for any combined cycle, base load turbine. Since add-on controls have previously been shown to be not technically feasible for application to the proposed dual fuel fired simple cycle peakers (and would not be cost effective in any case), the lowest emission rate continuously achievable using Dry low- NO_x combustors represents the next candidate for BACT. The Midway Energy Facility will utilize the lowest emitting DLN turbine technology on the market today to achieve a NO_x emission limit of 9 ppmvd @ 15% O_2 while firing natural gas, which therefore represents Best Available Control Technology (BACT).

While most of the discussion has been dealing with achievable NO_x emissions limits for natural gas fired operation, Midway Energy Center L.L.C. proposes a NO_x emission limit of 42 pmvd @ 15% O_2

achieved using water injection. Similar to other permits issued in Florida Midway Energy Center L.L.C. proposes that within 18 months after the initial compliance test, an engineering report will be prepared regarding the lowest NO_x emission rate that can be consistently achieved while firing distillate oil. This lowest NO_x emission rate would account for long-term performance expectations and reasonable operating margins. Based on the results of this report, the NO_x emission limit for distillate oil fired operation could be lowered.

5.3.4.1 Summary of Gas Turbine NO_x BACT

Midway Development Company L.L.C. proposes to implement NO_x BACT through the application of state-of-the-art GE 7FA turbines with 9 ppmvd @ 15% O_2 while firing natural gas, and 42 ppmvd @ 15% O_2 while firing distillate oil..

5.3.5 Natural Gas Fuel Heater

Based on a review of the RACT/BACT/LAER Clearinghouse the top NO_x control technology for heaters which fire less than 20 MMBtu/hr is the use of Low-NO_x burners. For a heater of this size, with limited hours of operation add-on control technology would not be cost effective. Midway Energy Facility will install a natural gas fired fuel heater equipped with Low-NO_x burner technology which will achieve a NO_x emission rate of less than 0.10 lb/MMBtu which will result in annual NO_x emissions of less than 2.3 tons/year. It should also be noted that the natural gas fuel heater is incorporated into this project to ensure that the natural gas fuel being used in the three combustion turbines is at the appropriate temperature for effective operation of GE's advanced DLN system.

5.4 BACT for Carbon Monoxide

5.4.1 Formation

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by water injection or aggressive dry lean pre-mix) tends to result in higher levels of CO emissions. Thus, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emission rates at acceptable levels.

5.4.2 Gas Turbines-Ranking of Available Control Techniques

CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Alternative Simple-Cycle turbine CO control methods include exhaust gas cleanup methods such as high temperature catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

A review of EPA's RACT/BACT/LAER Clearinghouse (Appendix C) indicates several levels of CO control which may be achieved for Simple-Cycle natural gas fired gas turbines. High temperature oxidation catalyst (analogous to high temperature SCR) is a relatively new add-on control technology that could be applied to Simple-Cycle peaking turbines. The Carson Energy project in California, a 64 MW peaker, uses this technology. As shown in Appendix C, the majority of projects in the Clearinghouse reference combustion controls (burner design) as BACT for CO. Emission levels and control technologies have been identified and ranked as follows:

- 2 to 6 ppm: High-temperature CO oxidation catalyst
- 10 to 50 ppm: Good combustion practices

These levels of CO control are evaluated in terms of Best Available Control Technology in the following sections.

5.4.2.1 LAER: 2 to 6 ppm CO with High-Temperature Catalytic Oxidation

The most stringent CO control level available for Simple-Cycle gas turbines would be achieved with the use of a high temperature (zeolite based) oxidation catalyst system, which can remove up to 90 percent of CO in the flue gas (Booth, 1998). According to the list of Simple-Cycle turbines in the RACT/BACT/LAER Clearinghouse with limits for CO, none are listed with high-temperature oxidation catalyst systems. Our search identified one Simple-Cycle peaking project in California, and Englehard offers the technology commercially. A high temperature CO oxidation catalyst is, therefore, concluded to represent a technically feasible add-on control technology to control CO from natural gas fired, Simple-Cycle turbines. This zeolite catalyst technology, however, exhibits many of the same start-up responsiveness limitations and negative environmental impacts expressed previously for high temperature SCR. The use of an oxidation catalyst would extend the startup period for the combustion turbines, and increase back pressure on the turbine, which in both cases would contribute to increased emissions of pollutants. Also the installation of an oxidation catalyst would contribute to increased formation of SO_3, which is a precursor for PM_{10} and H_2SO_4 formation.

<u>Technical Analysis</u>

As with SCR catalyst technology for NO_x control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to occur. Rather, the oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include turbine back pressure losses, unknown catalyst life due to masking or poisoning, greater emissions and reduced market responsiveness due to extended start-ups, and potential collateral increases in emissions of SO_3, sulfuric acid mist and condensible PM_{10}.

As with SCR, traditional CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 900°F.

Typical pressure losses across an oxidation catalyst reactor are in the range of 1.5 to 3.0 inches of water (Englehard, 1997). Pressure drops in this range correspond roughly to a 0.15 to 0.30 percent loss in power output and fuel efficiency (General Electric, 1997), or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

All catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement has been considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life, but no operating units were identified with more than about 3,500 hours. Periodic testing of catalyst material is necessary to predict actual catalyst life for a given installation. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system would also be expected to control as much as 40 percent of hydrocarbon (VOC) emissions.

Like high-temperature SCR, this technology has yet to be demonstrated-in-practice on Simple-Cycle turbines in this size range. It is, however, a passive control technology (does not require NH_3 injection) and can withstand higher turbine exhaust temperatures. It would however, limit the project's ability to come on line quickly enough to meet peak power market demand.

Environmental Analysis

A CO catalyst will also oxidize other species within the turbine exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, but will be further oxidized to SO_3 across a high temperature catalyst (70% conversion is assumed). SO_3 will be emitted and/or combined to form H_2SO_4 (sulfuric acid mist) in the exhaust stack or downstream in the ambient air. These sulfates condense as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and VOC, but would increase emissions of PM_{10} and $PM_{2.5}$.

The negative environmental impacts associated with this technology are less than for high-temperature SCR since no ammonia slip or ammonium salts are emitted. Collateral emissions due to efficiency losses or forced outages would still result in negative regional environmental impacts.

Economic Analysis

A high-temperature CO oxidation catalyst cost effectiveness evaluation was performed for the proposed Simple-Cycle General Electric 7FA turbines. Capital and annual costs associated with installation of a high temperature CO oxidation catalyst system were obtained from Engelhard, the vendor of high-temperature oxidation catalyst systems. Based on the quote from Engelhard (see Appendix C), the purchased equipment cost for each turbine is estimated at $1,484,700. Capital costs include the catalytic reactor, support structure, turbine transition piece, dilution air fan and flow straightener, spare parts and catalyst charge, freight, engineering and design, and installation. As shown in Table 5-5, when adding direct installation costs and indirect costs, the total capital cost (per turbine) is estimated at $2,390,300. Catalyst replacement is treated separately in this analysis as an operating cost. Annual operating costs, also summarized in Table 5-5, include operating labor (0.5 hour/shift), routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to increased back pressure. Annualized catalyst replacement cost was calculated based on a 3-year life.

Table 3-2 presents a worst-case CO emission estimate for the proposed project of 240 tons per year (79.6 tons per year per turbine). This estimate is based on 2,500 hours per year per turbine on natural gas at 50°F and 100 percent load and 1,000 hours per year per turbine on distillate oil at 50 °F and 100 percent load, which serves as a conservative estimate of the maximum annual emissions for the proposed turbines. The amount of CO removed annually by the oxidation catalyst would be 63.3 tons per turbine, based on estimated removal efficiency of 90 percent. The total annualized cost of oxidation catalyst for this case is estimated at $832,600, resulting in an overall cost-effectiveness of about $13,200 per ton of CO removed which is a prohibitive figure for non-LAER control of CO.

Another cost that has been removed from this analysis at the request of FL DEP is the lost revenue from this facility due to extended startup periods caused by the addition of an oxidation catalyst to the system. As the proposed turbines are intended to provide peak demand power, the ability to respond quickly to system demands is paramount to effective operation. Any operational constraints that restrict the ability of the proposed turbines to respond to these demands would result in lost revenues for the plant operators. The addition of an oxidation catalyst that is sensitive to sudden changes in temperature would require the plant operators to lengthen the startup sequence of the proposed turbines. A change of this type could potentially result in lost revenues in excess of $1,300,000 per year. If this cost is incorporated into the cost-effectiveness calculation the cost of installing an oxidation catalyst would exceed $30,000/ton.

5.4.2.2 Next Best Level of Control – 10 to 50 ppm with Combustion Control

The next best level of control is the General Electric 7FA combustors optimized CO emission rate of 9 ppmvd while firing natural gas and 20 ppmvd while firing distillate oil. This level of control is available, will not cause negative operational or environmental impacts, is cost effective, and represents BACT.

Summary

The use of a high temperature oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) NO_x, SO_2, and CO_2 emissions, is not cost effective, and does not represent BACT for the Midway Energy Center. Further, it would also lengthen peaking start-up times and limit the responsiveness of the project in its ability to address the peak power market. The next best level of control, 9 ppmvd while firing natural gas and 20 ppmvd while firing distillate oil using combustion control, is concluded to represent BACT for this facility.

5.4.3 Natural Gas Fuel Heater

The natural gas fuel heater will employ good combustion control for CO which has been determined to represent BACT for this source type. No add on control would be considered cost effective for control of CO emissions from this source.

Table 5-1 High Temperature Oxidation Catalyst (Carbon Monoxide) General Electric, Simple-Cycle, Model 7 FA

Facility Input Data

Item	Value
Operating Schedule	Assumed 8 hours per shift
Total Hours per year	3,500
Natural Gas Firing (Normal Operation)	2,500
Distillate Oil Firing (Normal Operation)	1,000
Source(s) Controlled[1]	One Power Block, 175 MW
CO From Normal Natural Gas Operation (lb/hr)	29.6
CO From Distillate Oil Operation (lb/hr)	66.6
CO From Source(s) (tpy)	70.3
Site Specific Enclosure (Building) Cost	NA
Site Specific Electricity Value ($/kWh)	0.10
Site Specific Natural Gas Cost ($/MMBtu)	NA
Site Specific Operating Labor Cost ($/hr)	30
Site Specific Maint. Labor Cost ($/hr)	30

[1]CO emissions are based on data at 100% load and intake air chilled to maximum of 50°F.

Capital Costs[1]

Item	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$1,227,000	Scaled Engelhard quote + auxiliaries, A
b.) Instrumentation	$122,700	0.10 x A
c.) Sales taxes	$61,400	0.05 x A
d.) Freight	$73,600	0.06 x A
Total Purchased equipment cost, (PEC)	$1,484,700	B = 1.21 x A
2.) Direct installation costs		
a.) Foundations and supports	$118,800	0.08 x B
b.) Handling and erection	$207,900	0.14 x B
c.) Electrical	$59,400	0.04 x B
d.) Piping	$29,700	0.02 x B
e.) Insulation for ductwork	$14,800	0.01 x B
f.) Painting	$14,800	0.01 x B
Total direct installation cost	$445,400	0.30 x B
3.) Site preparation, SP	NA	NA
4.) Buildings, Bldg	NA	NA
Total Direct Cost, DC	$1,930,100	1.30B + SP + Bldg
Indirect Costs (installation)		
5.) Engineering	$148,500	0.10 x B
6.) Construction and field expenses	$74,200	0.05 x B
7.) Contractor fees	$148,500	0.10 x B
8.) Start-up	$29,700	0.02 x B
9.) Performance test	$14,800	0.01 x B
10.) Contingencies	$44,500	0.03 x B
Total Indirect Cost, IC	$460,200	0.28B
Total Capital Investment (TCI) = DC + IC	**$2,390,300**	**1.58B + SP + Bldg**

1 See Appendix C, Tables C-1 and C-1A

Table 5-5 High Temperature Oxidation Catalyst (Carbon Monoxide) General Electric, Simple-Cycle, Model 7 FA (Continued)

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Press. Drop (in. W.C.)	2.2	Pressure drop - catalyst bed	Vendor
Power Output of Turbine (kW)	175,000		
Power Loss Due to Pressure Drop (%)	0.23%	0.105% for every 1" pressure drop	Vendor
Power Loss Due to Pressure Drop (kW)	404		
Unit Cost ($/kWh)	$0.10	Estimated Market Value	Estimate
Cost of Heat Rate Loss ($/yr)	$141,490		
Fan for Ambient Air Cooling (kW)	75	Estimated from Cooling Air Requirements	
Energy Required for Fan (kWh)	262,500		
Unit Cost ($/kW-hr)	$0.10	Estimated Market Value	Estimate
Cost of Cooling Fan Power ($)	$26,250		
Total Electricity Cost ($)	$167,740		
2) Operating Labor			
Requirement (hr/yr)	218.75	1/2 hr/shift, 3,500 hours per year	OAQPS
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Cost ($/yr)	$6,560		
3) Supervisory Labor			
Cost ($/yr)	$980	15% Operating Labor	OAQPS
4] Maintenance			
Labor Req. (hr/shift)	218.75	1/2 hour per shift	OAQPS
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Labor Cost ($/yr)	$6,563		
Material Cost ($/yr)	$6,560	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$13,120		
7) Catalyst Replacement			
Catalyst Cost ($)	$680,000	Catalyst modules	Vendor
Catalyst Disposal Cost ($)	$50,000	Disposal of catalyst modules	Estimate
Sales Tax ($)	$34,000	5% sales tax in Indiana	Estimate
Catalyst Life (yrs)	3	n	OAQPS
Interest Rate (%)	7	i	
CRF	0.38	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$291,120	(Volume)(Unit Cost)(CRF)	
9] Indirect Annual Costs			
Overhead	$12,400	60% of O&M Costs	OAQPS
Administration	$47,800	2% of Total Capital Investment	OAQPS
Property Tax	$23,900	1% of Total Capital Investment	OAQPS
Insurance	$23,900	1% of Total Capital Investment	OAQPS
Capital Recovery	$245,100	10 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	$353,100		

Total Annualized Cost ($/yr)	**$832,600**
Total CO Controlled (tpy)	**63.3**
Cost Effectiveness ($/ton)	**$13,200**

Additional Cost of Extended Startup sequence.

Power Loss Due to Extended Startups (kW-hr)	13,125,000	Extended startup time due to catalyst bed	Estimate
Cost of Extra Startups ($/yr)	$1,312,500	$0.10/kWh	

Total Annualized Cost ($/yr)	**$2,145,100**
Total CO Controlled (tpy)	**63.3**
Cost Effectiveness ($/ton)	**$33,900**

5.5 BACT for Particulate Matter and Trace Metals

5.5.1 Formation

Particulate (PM) emissions from natural gas and distillate oil combustion sources consist of inert contaminants in the fuel, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulates of carbon and hydrocarbons resulting from incomplete combustion, and condensibles, including sulfates and nitrates. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions. Trace metals that may be emitted from natural gas combustion are discussed in this section because they form a portion of particulate emissions. Lead and mercury, which are regulated in Florida's SIP regulations, may be a metal constituent of distillate fuel oils. However, neither lead nor mercury are estimated to emit more than the significant emission rates established in 40 CFR 52.21.

5.5.2 Gas Turbines

When the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that "particulate emissions from stationary gas turbines are minimal," and noted that particulate control devices are not typically installed on gas turbines and that the cost of installing a particulate control device is prohibitive (U.S. EPA, September 1977). Performance standards for particulate control of stationary gas turbines were, therefore, not proposed or promulgated.

The most stringent particulate control method demonstrated for gas turbines or diesel engines is the use of low ash fuel (such as natural gas or low sulfur transportation diesel) and the avoidance of catalytic technologies such as SCR when not required for LAER. No particulate matter or mercury-specific add-on control technologies are listed in the RACT/BACT/LAER Clearinghouse listings for Simple Cycle combustion turbines as shown in Appendix C. Proper combustion control and the firing of fuels with negligible or zero ash content (natural gas and 0.05% sulfur transportation diesel) is the predominant control method listed.

Add on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas fired turbines. The use of ESPs or baghouse filters is technically infeasible, and does not represent an available control technology.

The use of negligible or zero ash fuels such as natural gas and low sulfur diesel, and good combustion control is concluded to represent BACT for PM control for the proposed Simple-Cycle peaking turbines and diesel engine. BACT for PM_{10} precludes the selection of high-temperature SCR for NO_x control as NH3 slip at 10 ppm could result in additional PM_{10} (and PM_{10} precursor) emissions.

5.5.3 Natural Gas Fuel Heater

The most stringent particulate control method demonstrated for, natural gas fired heaters is the use of low ash fuel (such as natural gas). Proper combustion control and the firing of fuels with negligible or zero ash content is the predominant control method listed in the RACT/BACT/LAER Clearinghouse for similar sources. Add-on controls, such as ESPs or baghouses, have never been applied to small natural gas fired heaters. The use of ESPs and baghouse filters is considered technically infeasible, and does not represent an available control technology.

5.6 BACT for Sulfur Dioxide and Sulfuric Acid Mist

5.6.1 Formation

Sulfur dioxide (SO_2) is exclusively formed through the oxidation of sulfur present in the fuel. The emission rate is a function of the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_2. Another by-product of sulfur oxidation is when sulfur trioxide (SO_3) combines with water to form sulfuric acid (H_2SO_4). As a condensable gas, the sulfuric acid will appear in mist form in the stack if the temperatures are sufficiently low for condensation to occur. Since the stack exhaust will be in the 1050°F – 1250°F range, and the boiling point of sulfuric acid is less than 650°F, sulfuric acid mist will not form in the stack.

5.6.2 Gas Turbines and Fuel Gas Heater

The proposed simple cycle gas turbines will fire pipeline-quality natural gas and low sulfur transportation grade distillate fuel, the natural gas fuel heater will fire pipeline-quality natural gas only. Pipeline grade natural gas typically averages between 1-10 grains of sulfur per hundred standard cubic feet gas. A review of EPA RACT/BACT/LAER Clearinghouse information shows low sulfur fuel as the only available SO_2 control method selected as BACT in previous determinations for gas turbines. This indicates that the firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel is the most stringent SO_2 control methodology that has been demonstrated in practice for any combustion turbine. Therefore, this evaluation concludes that that firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel in the proposed Simple-Cycle peaking turbines and pipeline quality natural gas in the proposed fuel gas heater is BACT for SO_2.

If BACT were to be applied to H_2SO_4, which would preclude the use of an oxidation catalyst or SCR as the catalysts would further oxidize SO_2 to SO_3 which is a precursor of H_2SO_4. We should also state that H_2SO_4 would not be directly emitted from the turbine stack as the stack temperatures are too high. We should state that even though H_2SO_4 would not be emitted directly the test method used for sampling SO_2 if used could cause the formation of H_2SO_4 when the sample is cooled.

5.7 Summary and Conclusions

A summary of technologies determined to represent BACT for the MEC project is are presented in Table 5-6. Expected total emissions are summarized in Section 3 which are estimated based on 100% load for 3,500 hours per year including up to 1,000 hours per year of distillate oil operation and application of BACT as determined in this analysis.

Table 5-1 Summary of Selected BACTs

Pollutant	Gas Turbines
NO_x	Dry Low NO_x Combustors with Natural Gas (9 ppmvd, 15% O_2, 24 hour average, Water injection with Distillate Oil (42 ppmvd, 15% O_2)
CO	Good combustion control (9 ppmvd with Natural Gas, 20 ppmvd with Distillate Oil)
PM	Good combustion control; low ash, low sulfur fuel
SO_2	Low sulfur fuel; natural gas (2 grains S / 100 scf gas) distillate oil (0.05 wt% S)

6.0 AMBIENT AIR QUALITY IMPACT ANALYSIS

6.1 Overview of Analysis Methodology

The PSD rules require an analysis of the impact of the proposed facility on ambient concentrations of pollutants emitted in significant quantities, for which there is a National Ambient Air Quality Standard or PSD Increment. For the proposed facility, this includes NO_x, CO, SO_2, and PM_{10}. Although the project is not subject to PSD review for lead, the air quality standards analysis included a compliance assessment of this pollutant.

The ambient concentrations of PSD pollutants resulting from allowable emissions from the proposed facility are predicted using an approved U.S. EPA atmospheric dispersion model in accordance with U.S. EPA's "Guideline on Air Quality Models" (U.S. EPA, 1999). The atmospheric dispersion of emissions is simulated for a record of representative sequential hourly meteorological conditions over a historical five-year period. Ground-level concentrations at various averaging periods depending on the pollutant are predicted for a grid of ground-level model "receptors" surrounding the proposed facility. The following sections detail the specific aspects of the ambient air quality impact analysis.

6.2 Model Selection

The selection of an appropriate dispersion model must take into consideration the physical geometry of the sources, the local dispersion environment, and terrain characteristics. These factors, which formulate the basis for choosing one or more of the models recommended in the U.S. EPA modeling guidelines for both screening and refined modeling, are discussed below.

6.2.1 Physical Source Geometry

The sources of PSD pollutants from the proposed facility consist of high velocity, high temperature exhausts from stacks connected to the combustion turbines. This requires the use of a model capable of simulating the dispersion of buoyant releases from elevated point sources. The U.S. EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from elevated point sources. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" (GEP) stack height analysis. Stacks with heights below physical GEP are considered to be subject to building downwash. In the absence of structural effects, U.S. EPA has established a "default" GEP height of 213 feet. Any portion of a stack above the maximum of the physical or default GEP height cannot be used in the dispersion modeling analysis for purposes of comparison to U.S EPA's ambient impact criteria.

Each of the three combustion turbines at the proposed facility will have its own stack. A GEP stack height analysis was performed for the proposed project configuration in accordance with U.S. EPA's guidelines (U.S. EPA, 1985). Per the guidelines, the physical GEP height, H_{GEP}, is determined from the dimensions of all buildings which are within the region of influence using the following equation:

$$H_g = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_g, and

L = lesser dimension (height or projected width) of the structure.

For a squat structure, i.e., height less than projected width, the formula reduces to:

$$H_g = 2.5H$$

In the absence of influencing structures, a "default" GEP stack height is credited up to 65 meters (213 feet). The locations and dimensions of the various structures at the proposed facility relative to the exhaust stacks are depicted in Figure 6-1. An analysis of the potential for building downwash is presented below.

The significant structures of the proposed facility will include the turbine enclosures, turbine air intake structures, control room/electrical room/administration building, water storage tanks, and fuel storage tanks. U.S. EPA's Building Profile Input Processor (BPIP), as implemented in Lakes-Environmental *BPIP View* software, was used to determine the GEP stack height and to develop building input data for the modeling analysis. The output of the BPIP analysis is provided in Appendix D. A summary of the GEP analysis and the controlling building is provided in Table 6-1. The table lists the physical GEP stack height calculated for each influencing structure. Based on the BPIP analysis, the GEP stack height for the turbine stacks is 135 feet. Since the proposed height of the combustion turbine stacks is 80 feet, building downwash affects must be simulated in the dispersion modeling analysis. Also, since the stacks are less than the default GEP height of 213 feet, their full height can be considered in the modeling.

Figure 6-1 Location of Turbine Stacks Relative to Structures Included in the GEP Analysis

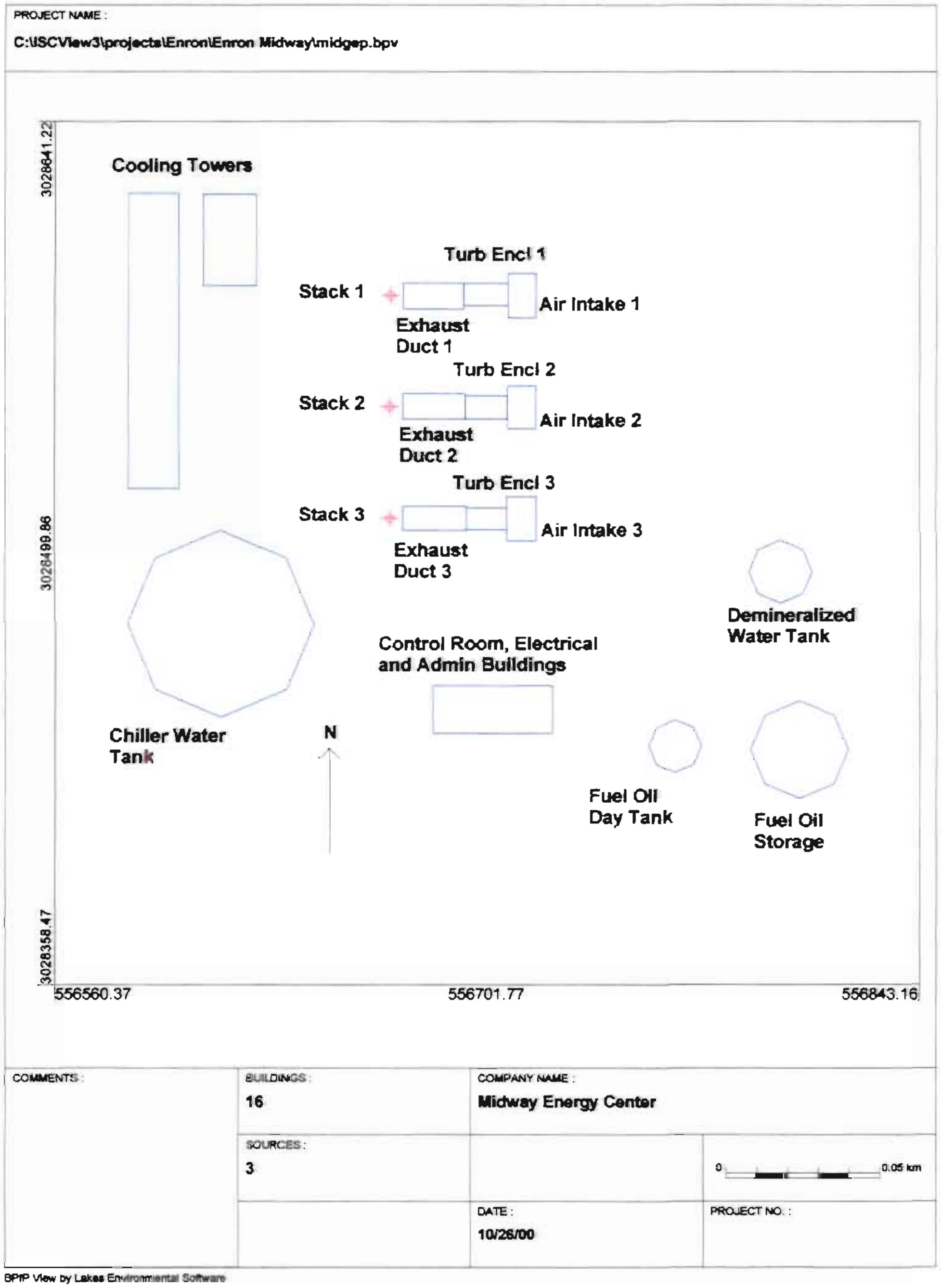


Table 6-1 Summary of GEP Analysis (Units in Feet)

Structure	Height	Length	Width	MPW(2)	GEP Formula Height	5L(3)	Distance to Turbine Stack (4)	Turbine Stack(s) Potentially Effected By Downwash Yes/No
Turbine Air Intake(1)	54	45	36	57	135	270	112	Yes
Turbine Enclosure (1)	45	49	23	54	113	225	62	Yes
Exhaust Duct (1)	27	62	26	67	67.5	135	0	Yes
Control/Admin Building	45	110	45	119	112.5	225	180	Yes
Chiller Water Tank	48	210	210	210	120	240	105	Yes
Demineralized Water Tank	48	59	59	59	120	240	380	No
Fuel Oil Day Tank	40	55	55	55	100	200	355	No
Fuel Oil Storage Tank	48	100	100	100	120	240	440	No
Chiller	8	310	50	315	20	40	135	No

(1) One associated with each turbine (see Figure 6-1).
(2) Maximum projected width.
(3) 5 times the lessor of the MPW or height is the maximum influence region.
(4) Closest distance relative to all turbine stacks.

6.2.2 Dispersion Environment

The selection and application of the model requires characterization of the local (within 3 km) dispersion environment as either urban or rural, based on a U.S. EPA-recommended procedure that characterizes an area by prevalent land use. This land use approach classifies an area according to 12 land use types. In this scheme, areas of industrial, commercial, and compact residential land use are designated urban. According to U.S. EPA modeling guidelines, if more than 50 percent of an area within a three-kilometer radius of the proposed facility is classified as rural, then rural dispersion coefficients are to be used in the dispersion modeling analysis.

For this analysis, the 1:24,000 scale United States Geological Survey (USGS) topographic maps for West Dixie Bend was obtained. Visual observation of the land use depicted on these maps clearly indicates that the region within 3 km is predominately rural.

6.2.3 Terrain Considerations

The U.S. EPA modeling guidelines require that the differences in terrain elevations, between the stack base and each location (receptor) at which air quality impacts are predicted, be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;

- intermediate terrain – locations where the terrain is between the height of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological condition);
- complex terrain – locations where the terrain is above the plume centerline.

Based on a review of USGS topographical maps, the area throughout the modeling domain is generally flat. The dispersion model must therefore be capable of simulating impacts on simple terrain only.

Based on a review of the factors discussed above, the ISCST3-Version 00101 dispersion model was selected for use in the modeling analysis.

6.3 Model Application

The ISCST3 model was used to calculate concentrations at simple receptor locations. The model was applied using the ISCST3 regulatory default option, in accordance with the U.S. EPA Guidelines.

6.3.1 Meteorological Data

The ISCST3 model requires a sequential hourly record of dispersion meteorology representative of the region within which the proposed source is located. In the absence of site-specific measurements, the EPA Guidelines recommend the use of data from nearby National Weather Service (NWS) stations, provided they are representative. For this analysis a five-year sequential meteorological data set was used consisting of surface observations and concurrent mixing height data from the NWS station at West Palm Beach International airport from 1987 through 1991. The West Palm Beach data are the closest representative data available and were recommended by the DEP for use in this application. The DEP provided the data in the processed format required for input to ISCST3.

6.3.2 Model Receptor Grid

A cartesian receptor grid was generated for use in the ISCST3 modeling. The grid consisted of densely spaced receptors at 100 meters apart starting at and extending to 3000 meters from the fenceline. Beyond 3000 meters, a spacing of 500 meters was used out to five kilometers from the facility. From six to ten kilometers, a spacing of 1000 meters was used. Between ten and twenty kilometers, a spacing of 2000 meters was used. Additional receptors were placed approximately every 50 meters along the property fence-line for increased resolution of impacts. As recommended by DEP, terrain elevations were not used for the receptors given that the terrain in the study area is generally flat. The extent of this grid was sufficient to capture maximum impacts.

Figure 6-2 shows the near-field receptors (out to three kilometers) including the near-field portion of the cartesian grid and fence-line receptors. The full cartesian receptor grid out to twenty kilometers is shown in Figure 6-3.

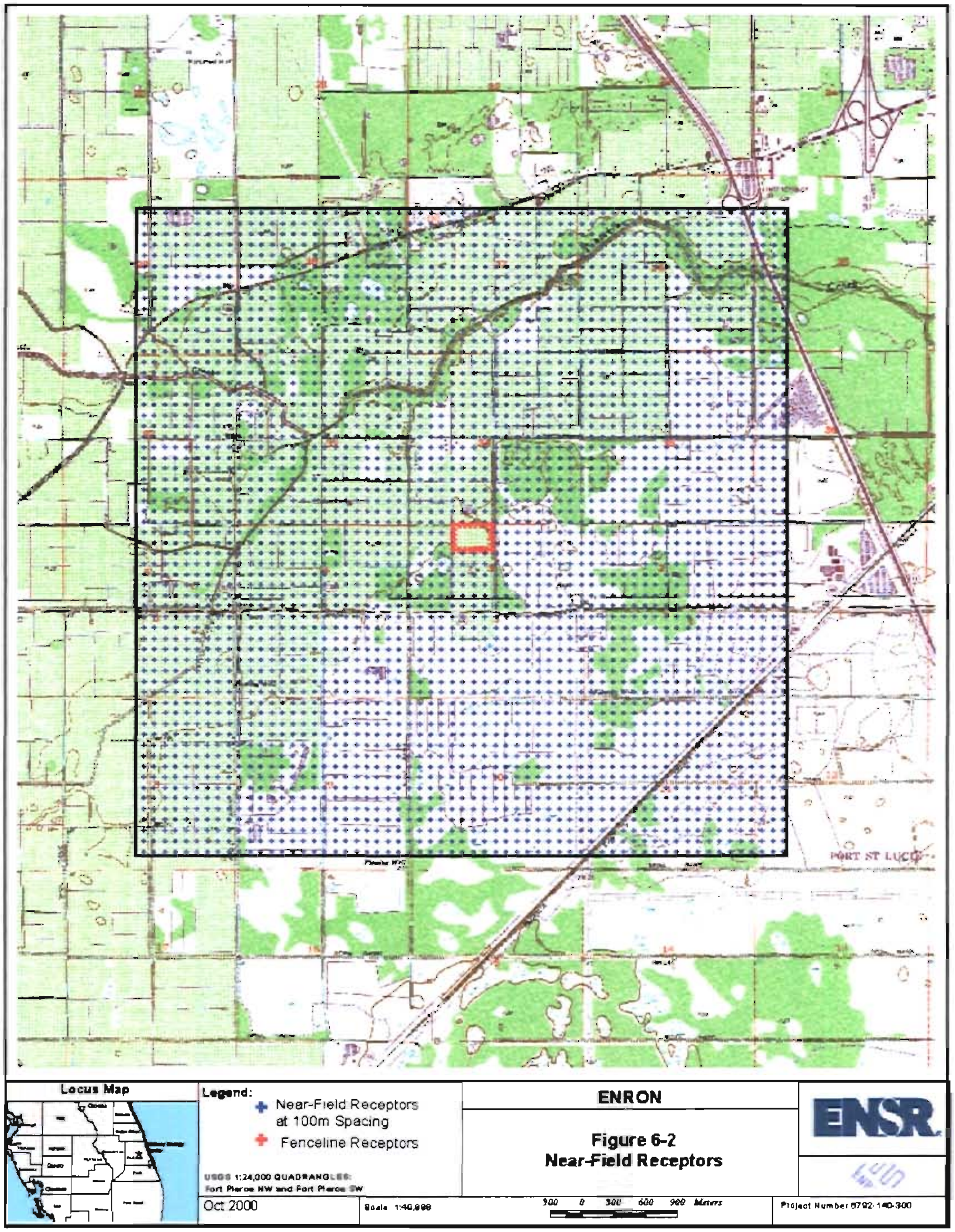
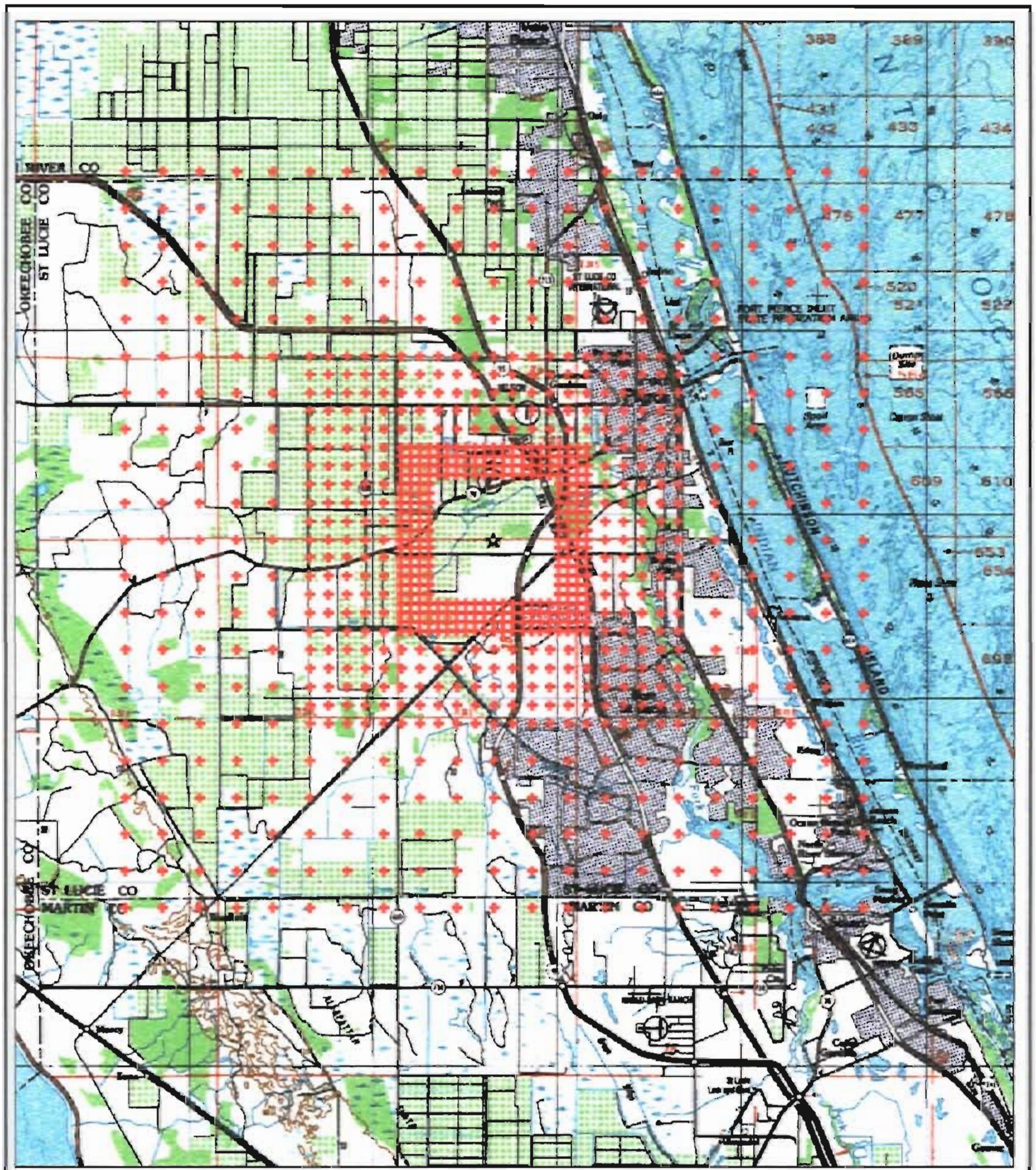


Figure 6-2
Near-Field Receptors



Locus Map

Legend:
Far-Field 20km Receptor Grid
Midway Energy Center

USGS 1:250,000 QUADRANGLES:
West Palm Beach and Fort Pierce

ENRON

Figure 6-3
Far-Field Receptors

ENSR

Scale 1: 313,674

Project Number 6792-140-300

6.3.3 Physical Source and Emissions Data

The air dispersion modeling analysis was conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) that are expected to represent the worst-case parameters among the range of possible values for the GE turbine model under consideration. Because turbine emission rates and flue gas characteristics for a given turbine load vary as a function of ambient temperature and fuel use, data were derived for four ambient temperatures for each proposed fuel at each of the three operating load scenarios (100%, 75% and 50%). The temperatures selected were:

- 30°F, an extreme lower boundary
- 42°F,
- 50°F, the effective inlet air temperature when the chillers are operating
- 91°F, a representative upper boundary

A summary of the exhaust data and emission rates for the PSD regulated pollutants for each fuel at each temperature and the three operating loads is provided in Table 6-2 for the GE 7FA turbines. Detailed calculations of the emissions parameters are presented in Appendix B.

In order to conservatively calculate ground-level concentrations, a composite "worst-case" set of emissions parameters was developed for each proposed fuel for input to the modeling. For each operating load, the highest pollutant-specific emission rate, the lowest exhaust temperature and the lowest exhaust flow rate were selected. Table 6-3 summarizes the worst-case emissions parameters for the two fuels at three operating loads.

Wind-direction-specific dimensions of the structures potentially causing building downwash of the turbine stacks were derived using the U.S. EPA BPIP processor. The BPIP inputs to the ISCST3 model are provided in Appendix D.

6.4 Ambient Impact Criteria

The U.S. EPA has established specific ambient impact criteria against which to evaluate the impact of a proposed new source. These are listed in Table 6-4 for the pollutants considered in this analysis. A description of each of the criteria and the relevance to the PSD application is described below.

Table 6-1 Combustion Turbine Performance Data for Natural Gas and Distillate Fuel Oil Operation

100 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1149	1109	1100	1087
Exit Velocity (Ft./sec)		150.4	160.6	162.0	164.0
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	71.4	79.5	80.5	82.1
	CO	26.5	29.6	30.1	30.9
	SO_2	9.5	10.6	10.7	10.9
	PM_{10}	18.0	18.0	18.0	18.0

75 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1180	1147	1142	1134
Exit Velocity (Ft./sec)		125.8	130.8	131.5	132.7
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	58.0	63.4	64.1	65.3
	CO	21.8	23.5	23.8	24.3
	SO_2	7.8	8.5	8.6	8.8
	PM_{10}	18.0	18.0	18.0	18.0

50 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1200	1194	1189	1182
Exit Velocity (Ft./sec)		106.9	111.3	111.8	112.4
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	45.9	50.3	50.8	51.6
	CO	18.4	19.5	19.7	20.0
	SO_2	0.9	1.0	1.1	1.1
	PM_{10}	18.0	18.0	18.0	18.0

Table 6-2 Combustion Turbine Performance Data for Natural Gas and Distillate Fuel Oil Operation (continued)

100 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1138	1088	1079	1065
Exit Velocity (Ft./sec)		154.4	165.0	166.5	168.6
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	289.6	321.0	325.5	332.1
	CO	59.5	66.6	67.8	69.6
	SO_2	90.3	100.2	101.6	103.6
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.03	0.03	0.03	0.03

75 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1186	1153	1148	1142
Exit Velocity (Ft./sec)		128.3	133.0	134.0	135.5
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	232.7	254.0	257.9	263.2
	CO	50.7	56.8	57.5	58.5
	SO_2	73.3	80.0	81.3	82.9
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.02	0.02	0.02	0.02

50 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1200	1200	1200	1193
Exit Velocity (Ft./sec)		109.0	112.5	112.9	113.4
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	181.9	199.2	201.5	204.6
	CO	78.3	66.5	64.6	67.6
	SO_2	57.9	63.4	64.2	65.1
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.02	0.02	0.02	0.02

Table 6-2 Worst-Case Turbine Stack Data for Dispersion Modeling

Natural Gas Operation

Parameter		Value		
Load (%)		100	75	50
Stack Height (Ft.)		80	80	80
Stack Diameter (Ft.)		18	18	18
Exit Temperature (^oF)		1087	1134	1182
Exit Velocity (Ft./sec)		150.4	125.8	106.9
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	82.1	65.3	51.6
	CO	30.9	24.3	20.0
	SO_2	10.9	8.8	7.0
	PM_{10}	18.0	18.0	18.0

No. 2 Fuel Operation

Parameter		Value		
Load (%)		100	75	50
Stack Height (Ft.)		80	80	80
Stack Diameter (Ft.)		18	18	18
Exit Temperature (^oF)		1065	1142	1193
Exit Velocity (Ft./sec)		154.4	128.3	109.0
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	332.1	263.2	204.6
	CO	69.6	58.5	78.3
	SO2	103.6	82.9	65.1
	PM_{10}	34.0	34.0	34.0
	Lead	0.028	0.023	0.018

Table 6-3 Ambient Impact Criteria[1]

Pollutant	Averaging Period	NAAQS Primary	NAAQS Secondary	Maximum Allowable PSD Class II Increments	PSD Significant Monitoring Concentration	PSD Class II Significant Impact Levels	PSD Class I Significant Impact Levels
NO_2	Annual	100	100	25	14	1	0.1
CO	1-hour	40,000	NA	NA	NA	2,000	NA
	8-hour	10,000	NA	NA	575	500	NA
PM_{10}	24-hour	150	150	30	10	5	0.3
	Annual	50	50	17	NA	1	0.2
SO_2	3-hour	NA	1300	512	NA	25	1.0
	24-hour	365	NA	91	13	5	0.2
	Annual	80	NA	20	NA	1	0.1
Lead	Quarter	1.5	1.5	NA	NA	NA	NA

[1] All values in $\mu g/m^3$. Annual averages are the maximum over all receptors. Short-term averages are the highest of the second-highest concentration over all receptors.
NA = Not Applicable

National Ambient Air Quality Standards (NAAQS)

National Ambient Air Quality Standards (NAAQS) are set by U.S. EPA, based on specific health and welfare effects criteria. Hence the term "criteria" pollutants. Ambient air refers to the air to which the general public is exposed, not the air inside buildings or in workplaces. The combined impacts of all existing sources cannot exceed the NAAQS. The primary NAAQS are established to protect the health of sensitive individuals. The secondary NAAQS are established to protect the general welfare of the public-at-large from adverse impacts on air quality related values such as visibility.

Allowable PSD Increments

The PSD increments are maximum allowable incremental increases in the ambient concentrations of the criteria pollutants in NAAQS attainment areas. The net combined impacts of all emissions increases and decreases from all sources occurring after a specified baseline date cannot exceed the PSD Increments. The PSD Class II increments apply to most areas of the country, including most of Florida with the exception of the designated PSD Class I areas. PSD Class I areas are National Parks and Wilderness Areas designated by U.S. EPA for special protection, including tighter PSD increments. The nearest PSD Class I area to the proposed facility is the Everglades National Park located about 180 kilometers to the southwest. New sources are presumed to have an insignificant impact on a PSD Class I area if maximum modeled impacts are less than the levels shown in Table 6-4. Since long range transport modeling involving the use of the CALPUFF dispersion model is required for the Class I impact assessment, a separate analysis is being completed for this assessment in coordination with the National Park Service Air Quality Division. The results of the PSD Class I area assessment will be submitted as a supplement to this permit application.

PSD Significant Monitoring Concentrations

PSD applicants can be granted a discretionary waiver from PSD pre-construction air quality monitoring requirements if the modeled impacts of the new source are below these concentrations.

PSD Significant Impact Levels

As can be seen from the concentrations representing these levels, the Significant Impact Levels (SILs) are small fractions of the NAAQS and PSD increments. The U.S. EPA guidelines require these levels to be used to determine the extent of the area surrounding a proposed source within which the source could significantly add to ambient air quality concentrations. For proposed sources whose impacts are above these levels, an analysis of the combined impacts of the proposed source with other existing sources is required. If a proposed source's impacts are below these levels it is considered to be unable to either cause or contribute to violations of the NAAQS, PSD Class II, or Class I increments. Therefore, a cumulative impact assessment is not required.

6.5 Results of Ambient Air Quality Impact Analysis

The emissions from the turbine stacks (3) were modeled with ISCST3 to estimate the maximum concentrations for the criteria pollutants including NO_x, PM/PM_{10}, SO_2, CO, and lead for each year of meteorological data. Note that the modeling of annual impacts reflects limited operation of the combustion turbines (3500 hours/year/turbine including up to 1,000 hours/year/turbine of distillate fuel oil usage).

Class II Area Receptors

Tables 6-5 and 6-6 provide summaries of the ISCST3 modeling results for NO_x, PM/PM_{10}, SO_2, CO, and lead for the Class II cartesian grid and fence-line receptors for natural gas and oil firing, respectively. The maximum air concentrations over the five years modeled and corresponding receptor locations are listed for each turbine load case (100%, 75% and 50%). The modeling results

Table 6-1 ISCST3 Modeling Results for Natural Gas

100% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.015	547670	3033548
PM-10	24-hour	0.149	540670	3038548
	Annual	0.004	547670	3033548
SO_2	3-hour	0.369	562670	3012548
	24-hour	0.090	540670	3038548
	Annual	0.003	547670	3033548
CO	1-hour	2.469	555670	3029848
	8-hour	0.619	538670	3024548

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

75% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.014	547670	3033548
PM-10	24-hour	0.224	556730.6	3028621
	Annual	0.005	547670	3033548
SO_2	3-hour	0.601	556770	3028648
	24-hour	0.110	556730.6	3028621
	Annual	0.003	547670	3033548
CO	1-hour	4.977	556770	3028648
	8-hour	0.908	556730.6	3028621

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

50% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.013	547670	3033548
PM-10	24-hour	0.323	556580.9	3028573
	Annual	0.006	547670	3033548
SO_2	3-hour	0.622	556470	3028548
	24-hour	0.126	556580.9	3028573
	Annual	0.002	547670	3033548
CO	1-hour	4.744	556770	3028648
	8-hour	0.881	556730.6	3028621

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

Table 6-2 ISCST3 Modeling Results for Distillate Oil

100% Load

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.023	547670	3033548
PM-10	24-hour	0.277	540670	3038548
	Annual	0.003	547670	3033548
SO_2	3-hour	3.441	562670	3012548
	24-hour	0.844	540670	3038548
	Annual	0.007	547670	3033548
CO	1-hour	5.546	555670	3029848
	8-hour	1.371	538670	3024548
Lead	24-hour	2.28E-04	540670	3038548

* Annual concentrations based on a maximum of 1000 hours/year of oil use.

75% Load

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.021	547670	3033548
PM-10	24-hour	0.414	556730.6	3028621
	Annual	0.003	547670	3033548
SO_2	3-hour	5.536	556770	3028648
	24-hour	1.009	556730.6	3028621
	Annual	0.007	547670	3033548
CO	1-hour	11.721	556770	3028648
	8-hour	2.135	556730.6	3028621
Lead	24-hour	3.41E-04	556730.6	3028621

* Annual concentrations based on a maximum of 1000 hours/year of oil use.

50% Load

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.019	547670	3033548
PM-10	24-hour	0.593	556580.9	3028573
	Annual	0.003	547670	3033548
SO_2	3-hour	5.638	556470	3028548
	24-hour	1.136	556580.9	3028573
	Annual	0.006	547670	3033548
CO	1-hour	18.168	556770	3028648
	8-hour	3.371	556730.6	3028621
Lead	24-hour	4.88E-04	556580.9	3028573

* Annual concentrations based on a maximum of 1000 hours/year of oil use.

for all years of modeling are provided in Appendix E. Note that in Table 6-5 (results for natural gas), the maximum annual concentrations are based on a maximum of 3500 hours/year of natural gas firing (i.e., the results have been scaled by a factor of 3500/8760). Similarly, in Table 6-6 (results for oil), the maximum annual concentrations are based on a maximum of 1,000 hours/year of oil firing (i.e., the results have been scaled by a factor of 1000/8760).

A comparison of the overall maximum pollutant impacts with the Class II Significant Impact Levels is presented in Table 6-7. For each pollutant and averaging period, the table lists the maximum predicted concentration for all fuels, years of meteorology, and worst-case turbine operating load. All of the modeled concentrations are below the SILs. Based on these results it can be concluded that the proposed facility will neither cause nor contribute to a violation of the NAAQS or PSD Class II increments. It is also pointed out that these impacts are below the relevant PSD significant monitoring concentrations as well. Thus, the facility is eligible for a waiver from pre-construction monitoring.

Table 6-3 Comparison of Maximum ISCST3 Concentrations to Class II Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration (µg/m³)*	SIL (µg/m³)
NO_X	Annual	0.034	1
PM-10	24-hour	0.593	5
	Annual	0.007	1
SO_2	3-hour	5.638	25
	24-hour	1.136	5
	Annual	0.009	1
CO	1-hour	18.168	2,000
	8-hour	3.371	500
Lead**	Quarterly	4.88E-04	1.5

*** Annual concentrations based on a worst-case composite of maximum natural gas concentration scaled by 2500 hours/year plus maximum oil concentration scaled by 1000 hours/year.**

**** Lead concentration is conservatively represented by the maximum 24-hour value. There is no SIL for Lead. The lead concentration is compared to the NAAQS.**

7.0 ADDITIONAL IMPACTS

The preceding sections of this permit application have focused on demonstrating the proposed action will incorporate Best Available Control Technology and will not have a significant impact on air quality. Beyond consideration of these basic air quality concerns, PSD regulations require a review of some of the more subtle effects a project may induce. The following section discusses the potential impacts which may result from the proposed project with respect to the following:

- Vegetation and Soils
- Associated Growth
- PSD Class I Area Impacts – Air Quality Increments, Regional Haze, and Deposition

7.1 Vegetation and Soils

The project lies in an area of primarily agricultural use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. The following discussion reviews the project's potential to impact its surroundings, based on the facility's PTE and the model-predictions of maximum ground level concentrations of SO_2, NO_x and CO, the PSD-applicable pollutants of concern for potential impact to soils and vegetation.

The criteria for evaluating impacts on soils and vegetation is taken from U.S. EPA's A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (U.S. EPA 1980). Table 7-1 lists the U.S. EPA suggested criteria for the gaseous pollutants emitted directly from the proposed facility and the predicted facility impacts. These criteria are established for sensitive vegetation and crops exposed to the effects of the gaseous pollutants through direct exposure. Adverse impacts on soil systems result more readily from the secondary effects of these pollutants' impacts on the stability of the soil system. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. Thus, the Table 7-1 criteria have been applied to the proposed facility to evaluate impacts on both soils and vegetation. As shown in Table 7-1, the results clearly indicate that no adverse impacts will occur to sensitive vegetation, crops, or soil systems as a result of operation of the proposed facility.

Table 7-1 Comparison to U.S. EPA Criteria for Gaseous Pollutant Impacts on Natural Vegetation and Crops

Pollutant	Averaging Time*	Minimum Impact Level for Affects On Sensitive Plants ($\mu g/m^3$)	Maximum Impact of Proposed Facility ($\mu g/m^3$)
SO_2	1 hour	917	16.61
	3 hours	786	5.64
	Annual	18	0.009
NO_x	4 hours	3760	17.72
	8 hours	3760	9.61
	1 month	564	3.57
	Annual	94	0.034
CO	1 week	1,800,000	1.37
*** 24-hour average used to conservatively represent 1-week and 1-month average impacts and 3-hour average used to conservatively represent 4-hour average impact.**			

7.2 Associated Growth

The proposed project will employ approximately 200 personnel during the construction phase. The project will employ approximately 10 personnel on a permanent basis. It is a goal of the project to hire from the local community when possible. There should be no substantial increase in community growth, or need for additional infrastructure. It is not anticipated that the proposed action will result in an increase in secondary emissions associated with non-project related activities. Therefore, in accordance with PSD guidelines, the analysis of ambient air quality impacts need consider only emissions from the facility itself.

7.3 Class I Area Impact Analysis

The nearest PSD Class I area to the proposed facility is the Everglades National Park located about 180 kilometers to the southwest. Based on discussions with John Notar of the National Park Service and Cleve Holladay of the FDEP, no Class I area impact analysis for the Everglades National Park is required for this project

APPENDIX A

FLORIDA DEP APPLICATION FORMS

Department of
Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Midway Development Company, L.L.C.**	
2. Site Name: **Midway Energy Center**	
3. Facility Identification Number: [✓] Unknown	
4. Facility Location: Street Address or Other Locator: **Northwest of the intersection of I-95 and W. Midway Rd** City: **Near Port St. Lucie** County: **St. Lucie** Zip Code: **34945**	
5. Relocatable Facility? [ ] Yes [✓] No	6. Existing Permitted Facility? [ ] Yes [✓] No

Application Contact

1. Name and Title of Application Contact: **Dave Kellermeyer, Director**
2. Application Contact Mailing Address: Organization/Firm: **Midway Development Company, L.L.C.** Street Address: **1400 Smith Street** City: **Houston** State: **TX** Zip Code: **77002-7631**
3. Application Contact Telephone Numbers: Telephone: **(713) 853-3161** Fax: **(713) 646-3037**

Application Processing Information (DEP Use)

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

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ______________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ______________________

Operation permit number to be revised: ______________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ______________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: ______________________

Reason for revision: ______________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[✓] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Ben Jacoby – Director**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Midway Development Company, L.L.C.** Street Address: **1400 Smith Street** City: **Houston** State: **TX** Zip Code: **77002-7631**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(713) 853-6173** Fax: **(713) 646-3037**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✓], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Ben J [signature] 1-5-01 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Blair Burgess** Registration Number: **45460**
2.	Professional Engineer Mailing Address: Organization/Firm: **ENSR** Street Address: **2809 West Mall Drive** City: **Florence** State: **AL** Zip Code: **35630**
3.	Professional Engineer Telephone Numbers: Telephone: **(256) 767-1210** Fax: **(256) 767-1211**

4. Professional Engineer Statement:

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

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

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

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

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

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

R. D. BURGESS, JR. CERTIFICATE No. 0048460 STATE OF FLORIDA REGISTERED ENGINEER 1/09/01

Signature ____________________ Date 1/09/01

(seal) EMBOSSED METALLIC

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
CT001 – CT003	PG7241S(FA) Simple Cycle Combustion Turbines (Three identical combustion turbines)	AC1A	$7,500 Similar emissions unit fee per Rule 62-4.050(4)(a)(4)
T001 – T002	Distillate Fuel Oil Storage Tanks (Main Tank and Day Tank)	AC1F	
NGH	Natural Gas Fuel Heater	ACIF	

Application Processing Fee

Check one: [] Attached - Amount: [✓] Not Applicable

Note: Due to previously-submitted and withdrawn permit applications, the parent company of Midway Energy Center has an existing positive application fee balance with the Florida Department of Environmental Protection.

Construction/Modification Information

1. Description of Proposed Project or Alterations **Midway Development Company, L.L.C. proposes to construct and operate a peaking electrical power generating facility at a greenfield site in St. Lucie County, Florida. The facility will consist of three (3) GE PG7241S(FA) (GE 7FA) combustion turbines operating in simple cycle mode; each turbine has a nominal generating capacity of 170 MW at ISO base rating. The combustion turbines will be fired up to 1,000 hours on low sulfur distillate oil, the remaining operation on natural gas, for a total of up to 3,500 hours. Ancillary equipment includes one 2.5 million gallon distillate oil main storage tank, one 617,400 gallon distillate oil day storage tank and one 13 MMBtu/hr natural gas fuel heater.**
2. Projected or Actual Date of Commencement of Construction: **April 1, 2001**
3. Projected Date of Completion of Construction: **May 1, 2002**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **556.7**	North (km): **3,028.5**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Dave Kellermeyer, Director**		
2. Facility Contact Mailing Address: Organization/Firm: **Midway Development Company, L.L.C.** Street Address: **1400 Smith Street** City: **Houston**	State: **TX**	Zip Code: **77002-7631**
3. Facility Contact Telephone Numbers: Telephone: **(713) 853-3161**	Fax: **(713) 646-3037**	

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations (Facility-wide)

Chapter 62-4	**Permits**
Rule 62-204.220	**Ambient Air Quality Protection**
Rule 62-204.240	**Ambient Air Quality Standards**
Rule 62-204.260	**Prevention of Significant Deterioration Increments**
Rule 62-204.800	**Federal Regulations Adopted by Reference**
Rule 62-210.300	**Permits Required**
Rule 62-210.350	**Public Notice and Comments**
Rule 62-210.370	**Reports**
Rule 62-210.550	**Stack Height Policy**
Rule 62-210.650	**Circumvention**
Rule 62-210.700	**Excess Emissions**
Rule 62-210.900	**Forms and Instructions**
Rule 62-212.300	**General Preconstruction Review Requirements**
Rule 62-212.400	**Prevention of Significant Deterioration**
Rule 62-213	**Operation Permits for Major Sources of Air Pollution**
Rule 62-214	**Requirements for Sources Subject to the Federal Acid Rain Program**
Rule 62-296.	**General Pollutant Emission Limiting Standards**
Rule 62-297.310	**General Test Requirements**
Rule 62-297.401	**Compliance Test Methods**
Rule 62-297.520	**EPA Continuous Monitor Performance Specifications**
40 CFR 60	**Applicable sections of Subpart A, General Requirements, NSPS Subparts GG and Kb**
40 CFR 72	**Acid Rain Permits**
40 CFR 75	**Monitoring**

40 CFR 77	Acid Rain Program – Excess Emissions

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**				
CO	**A**				
SO2	**A**				
VOC	**B**				**Units T001 and T002 subject to record keeping requirements of 40 CFR 60, Subpart Kb**
PM	**A**				
PM10	**A**				
PB	**B**				
H114	**B**				
SAM	**B**				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [✓] Attached, Document ID: **Fig. 1-1** [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [✓] Attached, Document ID: **Fig. 1-2** [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [✓] Attached, Document ID: **Fig. 2-1** [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [✓] Attached, Document ID: **ENSR Document No. 6792-140-300R** [ ] Not Applicable
7. Supplemental Requirements Comment: **See PSD BACT analysis in Section 5, air quality modeling results in Section 6, and additional impacts analysis in Section 7.**

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [✓] Attached, Document ID: **Section 2** [ ] Not Applicable **A qualifying insignificant emission units based on PTE is the fuel gas heater. See Appendix B for supporting emission calculations.**
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [✓] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [✓] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [✓] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [✓] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [✓] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [✓] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [✓] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[✓] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[✓] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
CT001 through CT003 are identical GE PG7241S(FA) (GE 7FA) simple cycle combustion turbines (CT) each having a nominal rating 170 megawatts (MW) at base load ISO conditions. Each CT will be fired with natural gas or low sulfur distillate oil.

4. Emissions Unit Identification Number: [✓] No ID
ID: **CT001; CT002; CT003** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**May 2002**	**49**	[✓]

9. Emissions Unit Comment: (Limit to 500 Characters)
Each combustion turbine (CT001, CT002, CT003) should be considered separate emissions units. The grouping of all turbines into one Emissions Unit Information Section has been done for administrative convenience since the information required in Subsections A through J is identical for each combustion turbine.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **NOx is limited through use of dry low NOx combustors for natural gas firing and water injection for distillate oil firing. See BACT analysis in Section 5.**	
2. Control Device or Method Code(s): **024**	

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **PG7241S(FA)**
2. Generator Nameplate Rating:	170 MW **(nominal @ base load ISO)**
3. Incinerator Information: **N/A**	
Dwell Temperature:	°F
Dwell Time:	seconds
Incinerator Afterburner Temperature:	°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Heat Input Rate: **2027 MMBtu** hr **HHV (base load on fuel oil @ 30°F)**			
2.	Maximum Incineration Rate:	**N/A** lb/hr		**N/A** tons/day
3.	Maximum Process or Throughput Rate: **N/A**			
4.	Maximum Production Rate: **N/A**			
5.	Requested Maximum Operating Schedule:			
		24 hours/day		**7** days/week
		52 weeks/year		**3500**[1] hours/year
6.	Operating Capacity/Schedule Comment (limit to 200 characters): **1 – Annual operations are based on a total of 3,500 hours per year per unit of which 1,000 hours per year per unit may be distillate fuel oil.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A (General Provisions for New Source Performance Standards)	
40 CFR 60.332(a)(1) – NO_x standards for Stationary Gas Turbines	
40 CFR 60.333 – SO_2 standards for Stationary Gas Turbines	
40 CFR 60.334 – Monitoring Provisions for Stationary Gas Turbines	
40 CFR Part 72 – Acid Rain Program Requirements Regulations	
40 CFR Part 73 – Acid Rain Program SO_2 Allowances System	
40 CFR Part 75 – Acid Rain Program Continuous Emissions Monitoring	
Rule 62-296.320(4)(b)1 – Visible emissions	
40 CFR 52.21 – Prevention of Significant Deterioration	
Rule 62-212.400 – Prevention of Significant Deterioration	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CT001, CT002, CT003**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhaust stacks for combustion turbines; one stack per turbine unit.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **80** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1109° F (NG)** **1088°F (Oil)**	9. Actual Volumetric Flow Rate: **2,451,600 acfm (NG)** **2,519,400 acfm (Oil)**	10. Water Vapor: **8.54 % (NG)** **11.05 % (Oil)**
11. Maximum Dry Standard Flow Rate: **754,000 dscfm (NG)** **764,000 dscfm (Oil)**		12. Nonstack Emission Point Height: N/A feet
13. Emission Point UTM Coordinates: **Zone: 17 CT001: East (km): 556.670 North (km): 3,028.584** **CT002: East (km): 556.670 North (km): 3,028.548** **CT003: East (km): 556.670 North (km): 3,028.511**		
14. Emission Point Comment (limit to 200 characters): **Exhaust temperatures and flow rates (items 8, 9, 10, 11) are at 100% load and 50° F operating conditions. It is expected that the proposed turbines will operate using inlet air chilling during summer peaking operations and as such the inlet air temperature will effectively be at 50° F during the majority of operating hours. Stack temperatures and flow rates will vary with load and ambient temperature.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural gas**		
1. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
6. Maximum Hourly Rate: **1.912 (per turbine)**	7. Maximum Annual Rate: **6,691 (per turbine)**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **2 grains/100 SCF**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **978 (HHV)**
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate is based on the hourly fuel consumption rate at base load, 50°F for 3500 hours per year.**		

Segment Description and Rate: Segment __2___ of __2___

2. Segment Description (Process/Fuel Type) (limit to 500 characters): **No. 2 Distillate Fuel Oil**		
3. Source Classification Code (SCC): **2-01-001-0**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **14.6 (per turbine)**	5. Maximum Annual Rate: **14,584 (per turbine)**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **Trace**	9. Million Btu per SCC Unit: **139 (HHV)**
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate is based on the hourly fuel consumption rate at base load and 50° F for 1,000 hours per year.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**024 (GE DLN on gas)/028 (oil firing)**		**EL**
CO	**0**		**EL**
PM	**0**		**EL**
PM10	**0**		**EL**
SO2	**0**		**EL**
VOC	**0**		**EL**
PB	**0**		**EL**
SAM	**0**		**EL**
H114	**0**		**EL**
EL-Annual emissions potential to emit is based on operating 3,500 hours per year at full load, with 1,000 hours on oil.			

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **332.1** lb/hour **(per turbine)** **235** tons/year (**per turbine**)	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **9 ppmvd @15%$_{O2}$ on gas** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual NOx emissions based on 2500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **9 ppmvd@15%O2 on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **61.6** lb/hour **235** tons/year
5. Method of Compliance (limit to 60 characters): **Compliance with 9 ppm limit during initial and annual performance stack tests using EPA Method 20. Compliance with 9 ppm limit shall be with CEM on a 24-hour block average.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2____ of ___2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **42 ppmvd@15% O_2 on oil for 1,000 of 3500 hours (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **332.1** lb/hour **235** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests with EPA Method 20. Continuous compliance based on CEM 3-hour average.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **78.3** lb/hour **(per turbine)** **70.3** tons/year **(per turbine)**	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **9 ppmvd @15% O_2 on gas** **30 ppmvd @15% O_2 on oil** Reference: **See Appendix B for emission calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperatures. Annual CO emissions based on 2500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **9 ppmvd @ 15% O_2 on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **30.9** lb/hour **70.3** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests using EPA Method 10.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **30 ppmdv @15% O_2 on oil (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **78.3** lb/hour **70.3** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests using EPA Method 10.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **34.0** lb/hour**(per turbine)** **39.5** tons/year **(per turbine)**	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.003 lb/MMBtu on oil** **0.017 lb/MMBtu on gas** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual PM/PM10 emissions based on 2500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **18 lb/hr on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **18** lb/hour **39.5** tons/year
5. Method of Compliance (limit to 60 characters): **Visible emissions testing as a surrogate for PM compliance testing.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2___ of __2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **34 lb/hr on oil (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **34** lb/hour **39.5** tons/year
5. Method of Compliance (limit to 60 characters): **Visible emissions testing as a surrogate for PM compliance testing.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.6** lb/hour **(per turbine)** **63.4** tons/year **(per turbines)**	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
7. Emission Factor: **0.02 gr S / SCF nat. gas.** **0.05% S in oil.** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual SO_2 emissions based on 2500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **10.9 lb/hr on gas (CT001, CT002, CT003)** **Sulfur content 2 gr/100 dscf**	4. Equivalent Allowable Emissions: **10.9** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Use of pipeline natural gas and custom fuel monitoring schedule.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions ___2___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **103.6 lb/hr on oil; 0.05% S content fuel**	4. Equivalent Allowable Emissions: **103.6** lb/hour **63.4** tons/year
5. Method of Compliance (limit to 60 characters): **Use of low sulfur distillate fuel oil.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.1** lb/hour **(per turbine) 5.1** tons/year **(per turbine)**	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.4 ppmvw** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual VOC emissions based on 2500 hours on gas and 1,000 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__ **N/A**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **3.0 lb/hr on natural gas**	4. Equivalent Allowable Emissions: **3.0** lb/hour **5.1** tons/year
5. Method of Compliance (limit to 60 characters): **Initial Stack Test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions ___2__ of ___2__

2. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
4. Requested Allowable Emissions and Units: **3.1 lb/hr on fuel oil**	4. Equivalent Allowable Emissions: **3.1** lb/hour **5.1** tons/year
5. Method of Compliance (limit to 60 characters): **Initial stack test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.028** lb/hour **(per turbine)** **0.014** tons/year **(per turbine)**	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.000014 lb/MMBtu** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Emission factor is for worst case, firing on distillate oil. No Pb is expected from natural gas combustion.**	

Allowable Emissions Allowable Emissions ______ of _____N/A_

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **15.9** lb/hour **(per turbine)** **9.7** tons/year **(per turbine)**	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.009 lb/MMBtu on oil** Reference: **See Appendix B for emissions calculations.**	8. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **SAM is not expected to be generated prior to leaving the stack, due to the high temperatures. However, precursor to SAM (SO3) is generated.**	

Allowable Emissions Allowable Emissions ______ of ______N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **H114**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.51 E-3** lb/hour **1.21 E-3** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 1.2 E-6 lb/MMBtu Reference: **See Appendix B for emissions calculations.**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission factor for mercury (Hg) is for worst case, firing on distillate oil. No Hg is expected from natural gas combustion.**	

Allowable Emissions Allowable Emissions ______ of ______N/A

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation __1__ of __1__

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [✓] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9.**	
5. Visible Emissions Comment (limit to 200 characters): **The general visible emission standard requirements of Rule 62-296.320(4)(b)1, F.A.C. apply to each turbine stack.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor __1__ of __1__

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✓] Rule (**NOX**) [ ] Other
4. Monitor Information: **TBD** Manufacturer: **TBD** Model Number: **TBD**	Serial Number: **TBD**
5. Installation Date: **Prior to start up**	6. Performance Specification Test Date: **90 days after unit commences commercial operation in accordance with 40 CFR 75.4(b)(2).**
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✓] Attached, Document ID:**Fig. 2-2** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✓] Attached, Document ID:**App. B** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [✓] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [✓] Attached, Document ID: **ENSR Doc. No. 6792-140-300R**
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✓] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [✓] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [✓] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [✓] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [✓] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [✓] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID: **To be supplied at a later date**

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [ ] Not Applicable

III. TANK EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[✓] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[✓] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Distillate fuel oil storage tanks

4. Emissions Unit Identification Number: [✓] No ID [ ] ID Unknown
ID: **T001, T002**

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**May 2002**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

T001 – main storage tank
T002 – day storage tank.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **None**
2. Control Device or Method Code(s):

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate: **N/A** mmBtu/hr	
2. Maximum Incineration Rate: **N/A** lb/hr	**N/A** tons/day
3. Maximum Process or Throughput Rate: **43,750,000 gal/year**	
4. Maximum Production Rate: **N/A**	
5. Requested Maximum Operating Schedule: **24** hours/day; **52** weeks/year	7 days/week; **8760** hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Peak demand anticipated June – August; December – February** **T001 – 2.5 MM gallon capacity** **T002 – 617,400 gallon capacity**	

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A (General Provisions for New Source Performance Standards)	
40 CFR 60.116b(a) and (b) – Record Keeping requirements under Subpart Kb	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **T001, T002**		2. Emission Point Type Code: **4**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **N/A** feet	7. Exit Diameter: **N/A** feet
8. Exit Temperature: **N/A**	9. Actual Volumetric Flow Rate: **N/A**	10. Water Vapor: **N/A**
11. Maximum Dry Standard Flow Rate: **N/A** dscfm		12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates: **Main tank: Zone 17; 556.763 East (km) 3,028.437 North (km)** **Day tank: Zone 17; 556.803 East (km) 3,028.435 North (km)**		
14. Emission Point Comment (limit to 200 characters):		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate fuel oil storage tanks**		
2. Source Classification Code (SCC): **40301021**	3. SCC Units: **Thousand Gallons Throughput**	
4. Maximum Hourly Rate: **N/A**	5. Maximum Annual Rate: **43,750**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ___ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Potential VOC emissions from distillate fuel oil storage tanks are less than 5 tons per year (less than the threshold amount for reporting in this subsection). See Appendix B for emission calculations.**	

Allowable Emissions Allowable Emissions **1** of **1** **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: **N/A**

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule (**NOX**) [ ] Other (**CO**)
4. Monitor Information: Manufacturer: Model Number:	 Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: [✓] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID: [✓] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [✓] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✓] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [✓] Attached, Document ID: **See calculations in Appendix B for tank information.**
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✓] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [✓] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [✓] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [✓] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [✓] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part – Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [✓] Not Applicable

APPENDIX B

EMISSION CALCULATIONS

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Natural Gas Only					Proposed Design Specification
Fuel Heating Value		(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content		(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	151000	174800	178000	182200		Manufacturer Supplied Data
Heat Input Rate		(MMBtu/Hr, LHV)	1,464.7	1,629.1	1,652.7	1,684.4		Manufacturer Supplied Data
Fuel Feed Rate		(SCF/Hr)	1,662,354	1,848,939	1,875,724	1,911,701		Calculated
Exhaust Temperature		(F)	1,149	1,109	1,100	1,087		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	150.4	160.6	162.0	164.0		Calculated
Exhaust Analysis	Argon		0.87	0.90	0.90	0.90		39.948 lb/lb mol Ar
	Nitrogen		72.83	74.32	74.55	74.94		28.0134 lb/lb mol N_2
	Oxygen		12.22	12.50	12.57	12.68		31.998 lb/lb mol O_2
	Carbon Dioxide		3.69	3.75	3.74	3.74		44.009 lb/lb mol CO_2
	Water		10.40	8.54	8.25	7.75		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.16	28.37	28.40	28.45		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	3,301,000	3,642,000	3,700,000	3,783,000		Manufacturer Supplied Data
		(ACFHW)	137,744,689	147,096,451	148,423,690	150,200,713		Calculated
		(ACFMW)	2,295,745	2,451,608	2,473,728	2,503,345		Calculated
		(ACFHD)	123,419,241	134,534,414	136,178,735	138,560,158		Calculated
		(ACFMD)	2,056,987	2,242,240	2,269,646	2,309,336		Calculated
		(SCFHW)	45,182,505	49,480,378	50,214,935	51,243,258		Calculated
		(SCFMW)	753,042	824,673	836,916	854,054		Calculated
		(SCFHD)	40,483,524	45,254,754	46,072,203	47,271,906		Calculated
		(SCFMD)	674,725	754,246	767,870	787,865		Calculated
Exhaust Moisture		(%)	10.40	8.54	8.25	7.75		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	13.64	13.67	13.70	13.75		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd)	11.1	11.0	11.0	10.9		Calculated
Concentration of CO in Exhaust		(ppmvd)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	7.3	7.3	7.4	7.4		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.5	1.5	1.5		Calculated
		(ppmvd @ 15% O2)	1.3	1.2	1.3	1.3		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine		
Project Number:	6792-140	Computed by: M. Lafond	Date: 9/24/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions	Checked by: M. Griffin	Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	53.5	59.6	60.4	61.6	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	26.5	29.6	30.1	30.9	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) *(Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.6	2.9	2.9	3.0	

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine			
Project Number:	6792-140	Computed by: M. Lafond	Date:	9/24/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions	Checked by: M. Griffin	Date:	9/26/00

SULFUR DIOXIDE

$$\text{Lbs/Hr} = \frac{\text{(Expected Fuel Gas Sulfur Content, Grains/SCF) * (Fuel Feed Rate, SCF/Hr) * (64 Lbs SO2/32 Lbs S)}}{\text{(7,000 Grains/Lbs)}}$$

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	9.5	10.6	10.7	10.9	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.5	1.6	1.6	1.7	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Natural Gas Only					Proposed Design Specification
Fuel Heating Value		(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content		(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	113300	131100	133500	136700		
Heat Input Rate		(MMBtu/Hr, LHV)	1,202.1	1,312.3	1,328.3	1,353.3		Manufacturer Supplied Data
Fuel Feed Rate		(SCF/Hr)	1,364,317	1,489,388	1,507,547	1,535,921		Calculated
Exhaust Temperature		(F)	1,180	1,147	1,142	1,134		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	125.8	130.8	131.5	132.7		Calculated
Exhaust Analysis	Argon		0.87	0.89	0.89	0.89		39.948 lb/lb mol Ar
	Nitrogen		72.86	74.31	74.53	74.90		28.0134 lb/lb mol N_2
	Oxygen		12.30	12.48	12.51	12.58		31.998 lb/lb mol O_2
	Carbon Dioxide		3.65	3.76	3.77	3.79		44.009 lb/lb mol CO_2
	Water		10.32	8.56	8.30	7.84		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.16	28.36	28.39	28.44		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	2,710,000	2,897,000	2,923,000	2,970,000		Manufacturer Supplied Data
		(ACFHW)	115,254,389	119,863,053	120,440,174	121,542,995		Calculated
		(ACFMW)	1,920,906	1,997,718	2,007,336	2,025,717		Calculated
		(ACFHD)	103,360,136	109,602,775	110,443,639	112,014,025		Calculated
		(ACFMD)	1,722,669	1,826,713	1,840,727	1,866,900		Calculated
		(SCFHW)	37,090,563	39,365,979	39,679,002	40,243,333		Calculated
		(SCFMW)	618,176	656,100	661,317	670,722		Calculated
		(SCFHD)	33,262,817	35,996,251	36,385,644	37,088,256		Calculated
		(SCFMD)	554,380	599,938	606,427	618,138		Calculated
Exhaust Moisture		(%)	10.32	8.56	8.30	7.84		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	13.72	13.65	13.64	13.65		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd)	11.0	11.1	11.1	11.1		Calculated
Concentration of CO in Exhaust		(ppmvd)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	7.4	7.3	7.3	7.3		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.5	1.5	1.5		Calculated
		(ppmvd @ 15% O2)	1.3	1.2	1.2	1.2		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	43.5	47.5	48.1	49.0	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	21.8	23.5	23.8	24.3	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) *(Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.2	2.3	2.3	2.3	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

$$\text{Lbs/Hr} = \frac{(\text{Expected Fuel Gas Sulfur Content, Grains/SCF}) * (\text{Fuel Feed Rate, SCF/Hr}) * (64 \text{ Lbs } SO_2/32 \text{ Lbs S})}{(7{,}000 \text{ Grains/Lbs})}$$

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	7.8	8.5	8.6	8.8	

SULFURIC ACID MIST

$$\text{Lbs/Hr} = \frac{(SO_2 \text{ Emission Rate, lb/hr}) * (SO_2 \text{ to } SO_3 \text{ Conversion Rate, lb/hr}) * (98.07 \text{ Lbs } SO_2/64.062 \text{ Lbs S})}{}$$

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.2	1.3	1.3	1.3	

Note:
Assume 10% conversion of SO_2 to SO_3. Assume all SO_3 is converted to H_2SO_4.

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

Notes:

CALCULATIONS AND COMPUTATIONS

Project: *Florida GE 7FA Turbine*
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Natural Gas Only					Proposed Design Specification
Fuel Heating Value		(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content		(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	75500	87400	89000	91100		
Heat Input Rate		(MMBtu/Hr, LHV)	961.1	1,052.3	1,063.6	1,079.5		Manufacturer Supplied Data
Fuel Feed Rate		(SCF/Hr)	1,090,796	1,194,303	1,207,127	1,225,173		Calculated
Exhaust Temperature		(F)	1,200	1,194	1,189	1,182		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	106.9	111.3	111.8	112.4		Calculated
Exhaust Analysis	Argon		0.88	0.88	0.89	0.90		39.948 lb/lb mol Ar
	Nitrogen		73.02	74.43	74.64	75.02		28.0134 lb/lb mol N_2
	Oxygen		12.76	12.81	12.84	12.90		31.998 lb/lb mol O_2
	Carbon Dioxide		3.44	3.61	3.62	3.64		44.009 lb/lb mol CO_2
	Water		9.91	8.27	8.01	7.55		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.19	28.38	28.41	28.46		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	2,278,000	2,396,000	2,416,000	2,444,000		Manufacturer Supplied Data
		(ACFHW)	97,960,041	101,973,241	102,405,341	102,950,915		Calculated
		(ACFMW)	1,632,667	1,699,554	1,706,756	1,715,849		Calculated
		(ACFHD)	88,252,201	93,540,054	94,202,673	95,178,121		Calculated
		(ACFMD)	1,470,870	1,559,001	1,570,045	1,586,302		Calculated
		(SCFHW)	31,145,092	32,538,669	32,775,647	33,090,761		Calculated
		(SCFMW)	519,085	542,311	546,261	551,513		Calculated
		(SCFHD)	28,058,613	29,847,721	30,150,318	30,592,408		Calculated
		(SCFMD)	467,644	497,462	502,505	509,873		Calculated
Exhaust Moisture		(%)	9.91	8.27	8.01	7.55		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	14.16	13.96	13.96	13.95		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd)	10.3	10.6	10.6	10.6		Calculated
Concentration of CO in Exhaust		(ppmvd)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	7.9	7.7	7.6	7.6		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.5	1.5	1.5		Calculated
		(ppmvd @ 15% O2)	1.4	1.3	1.3	1.3		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34.4	37.7	38.1	38.7	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18.4	19.5	19.7	20.0	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) * (Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.8	1.9	1.9	1.9	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Gas Sulfur Content, Grains/SCF) * (Fuel Feed Rate, SCF/Hr) * (64 Lbs SO2/32 Lbs S) / (7,000 Grains/Lbs)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	6.2	6.8	6.9	7.0	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.9	1.0	1.1	1.1	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

PARTICULATE MATTER

Base Equations

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	16	18	18	18	

Notes:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Distillate Oil					Proposed Design Specification
Fuel Heating Value		(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content		(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	160,800.00	182500	185,400.00	189300		
Heat Input Rate		(MMBtu/Hr, LHV)	1,645.0	1,825.0	1,851.2	1,887.3		Manufacturer Supplied Data
Fuel Feed Rate		(lb/Hr)	90,385	100,275	101,714	103,698		Calculated
Exhaust Temperature		(F)	1,138	1,088	1,079	1,065		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	154.4	165.0	166.5	168.6		Calculated
Exhaust Analysis	Argon		0.85	0.85	0.85	0.87		39.948 lb/lb mol Ar
	Nitrogen		70.33	71.37	71.56	71.86		28.0134 lb/lb mol N_2
	Oxygen		11.02	11.26	11.32	11.41		31.998 lb/lb mol O_2
	Carbon Dioxide		5.44	5.47	5.46	5.45		44.009 lb/lb mol CO_2
	Water		12.37	11.05	10.81	10.42		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.19	28.33	28.36	28.40		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	3,417,000	3,789,000	3,850,000	3,939,000		Manufacturer Supplied Data
		(ACFHW)	141,445,658	151,166,218	152,573,185	154,428,463		Calculated
		(ACFMW)	2,357,428	2,519,437	2,542,886	2,573,808		Calculated
		(ACFHD)	123,948,830	134,462,350	136,080,024	138,337,017		Calculated
		(ACFMD)	2,065,814	2,241,039	2,268,000	2,305,617		Calculated
		(SCFHW)	46,715,924	51,539,332	52,323,300	53,445,839		Calculated
		(SCFMW)	778,599	858,989	872,055	890,764		Calculated
		(SCFHD)	40,937,164	45,844,236	46,667,152	47,876,782		Calculated
		(SCFMD)	682,286	764,071	777,786	797,946		Calculated
Exhaust Moisture		(%)	12.37	11.05	10.81	10.42		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	12.58	12.66	12.69	12.74		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
		(ppmvd)	59.3	58.7	58.4	58.1		Calculated
Concentration of CO in Exhaust		(ppmvd)	20	20	20	20		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	14.2	14.3	14.4	14.5		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.6	1.6	1.6		Calculated
		(ppmvd @ 15% O2)	1.1	1.1	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	289.6	321.0	325.5	332.1	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) *(Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	59.5	66.6	67.8	69.6	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) *(Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.7	3.0	3.0	3.1	

CALLCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine		
Project Number:	6792-140	Computed by: M. Lafond	Date: 9/24/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions	Checked by: M. Griffin	Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	90.3	100.2	101.6	103.6	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	13.8	15.3	15.6	15.9	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	- 34	34	34	34	

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.025	0.027	0.028	0.028	

Note:
Use AP-42 Section 3.1 Emission Factor. 0.000014 lb/MMBtu

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Distillate Oil					Proposed Design Specification
Fuel Heating Value		(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content		(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	120,600	136,900	139,000	142,000		
Heat Input Rate		(MMBtu/Hr, LHV)	1,336.2	1,458.0	1,480.4	1,510.9		Manufacturer Supplied Data
Fuel Feed Rate		(lb/Hr)	73,418	80,110	81,341	83,016		Calculated
Exhaust Temperature		(F)	1,186	1,153	1,148	1,142		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	128.3	133.0	134.0	135.5		Calculated
Exhaust Analysis	Argon		0.85	0.85	0.86	0.86		39.948 lb/lb mol Ar
	Nitrogen		70.71	71.57	71.69	71.90		28.0134 lb/lb mol N_2
	Oxygen		11.15	11.13	11.13	11.14		31.998 lb/lb mol O_2
	Carbon Dioxide		5.42	5.60	5.62	5.65		44.009 lb/lb mol CO_2
	Water		11.88	10.86	10.71	10.45		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.24	28.37	28.39	28.42		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	2,761,000	2,934,000	2,968,000	3,015,000		Manufacturer Supplied Data
		(ACFHW)	117,511,976	121,810,383	122,756,013	124,110,414		Calculated
		(ACFMW)	1,958,533	2,030,173	2,045,934	2,068,507		Calculated
		(ACFHD)	103,551,553	108,581,776	109,608,844	111,140,876		Calculated
		(ACFMD)	1,725,859	1,809,696	1,826,814	1,852,348		Calculated
		(SCFHW)	37,679,209	39,856,688	40,291,021	40,888,162		Calculated
		(SCFMW)	627,987	664,278	671,517	681,469		Calculated
		(SCFHD)	33,202,919	35,528,252	35,975,853	36,615,349		Calculated
		(SCFMD)	553,382	592,138	599,598	610,256		Calculated
Exhaust Moisture		(%)	11.88	10.86	10.71	10.45		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	12.65	12.49	12.47	12.44		Calculated
Concentration of NOx in Exhaust		*(ppmvd@15% O2)*	42	42	42	42		*Manufacturer Supplied Data*
		(ppmvd)	58.7	59.9	60.0	60.2		Calculated
Concentration of CO in Exhaust		(ppmvd)	21	22	22	22		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	15.0	15.4	15.4	15.3		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.6	1.6	1.6		Calculated
		(ppmvd @ 15% O2)	1.1	1.1	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	232.7	254.0	257.9	263.2	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	50.7	56.8	57.5	58.5	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) * (Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.2	2.3	2.3	2.4	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	73.3	80.0	81.3	82.9	

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	11.2	12.2	12.4	12.7	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine			
Project	Number: 6792-140	Computed by: M. Lafond	Date:	9/25/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions	Checked by: M. Griffin	Date:	9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

Notes:

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.020	0.022	0.022	0.023	

Note:
Use AP-42 Section 3.1 Emission Factor. 0.000014 lb/MMBtu

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Distillate Oil					Proposed Design Specification
Fuel Heating Value		(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content		(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	80,400.00	91300	92,700.00	94600		
Heat Input Rate		(MMBtu/Hr, LHV)	1,054.8	1,155.9	1,168.9	1,186.3		Manufacturer Supplied Data
Fuel Feed Rate		(lb/Hr)	57,956	63,511	64,225	65,181		Calculated
Exhaust Temperature		(F)	1,200	1,200	1,200	1,193		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	109.0	112.5	112.9	113.4		Calculated
Exhaust Analysis	Argon		0.86	0.86	0.85	0.86		39.948 lb/lb mol Ar
	Nitrogen		71.45	72.18	72.29	72.53		28.0134 lb/lb mol N_2
	Oxygen		11.91	11.67	11.63	11.64		31.998 lb/lb mol O_2
	Carbon Dioxide		5.03	5.34	5.39	5.42		44.009 lb/lb mol CO_2
	Water		10.75	9.95	9.84	9.55		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.32	28.44	28.46	28.49		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	2,333,000	2,419,000	2,427,000	2,451,000		Manufacturer Supplied Data
		(ACFHW)	99,860,109	103,104,272	103,386,331	103,839,200		Calculated
		(ACFMW)	1,664,335	1,718,405	1,723,106	1,730,653		Calculated
		(ACFHD)	89,125,148	92,845,397	93,213,116	93,922,557		Calculated
		(ACFMD)	1,485,419	1,547,423	1,553,552	1,565,376		Calculated
		(SCFHW)	31,749,193	32,780,632	32,870,309	33,154,127		Calculated
		(SCFMW)	529,153	546,344	547,838	552,569		Calculated
		(SCFHD)	28,336,155	29,518,959	29,635,870	29,987,908		Calculated
		(SCFMD)	472,269	491,983	493,931	499,798		Calculated
Exhaust Moisture		(%)	10.75	9.95	9.84	9.55		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	13.34	12.96	12.90	12.87		*Calculated*
Concentration of NOx in Exhaust		(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
		(ppmvd)	53.8	56.5	57.0	57.2		Calculated
Concentration of CO in Exhaust		(ppmvd)	38	31	30	31		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	29.7	23.0	22.1	22.8		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.6	1.6	1.5		Calculated
		(ppmvd @ 15% O2)	1.2	1.2	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	181.9	199.2	201.5	204.6	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	78.3	66.5	64.6	67.6	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) * (Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.8	1.9	1.9	1.9	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	57.9	63.4	64.2	65.1	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	8.9	9.7	9.8	10.0	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

Notes:

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.016	0.017	0.018	0.018	

Note:
Use AP-42 Section 3.1 Emission Factor. 0.000014 lb/MMBtu

Midway Energy Center
Estimated NSPS NO_X Emission Standard

Turbine General Electric Model 7FA		
Natural Gas Firing		
Nominal Maximum Electrical Capacity	174.8	MW
Maximum Energy Input	1629.1	MMBtu/hr (LHV)
	1,719,677,960	kJ/hr
Heat Rate	9,320	Btu/kWh
	9.8	kJ/Wh
NSPS Subpart GG NOx Limit	0.0110%	Volume % NOx @ 15% O2
	110	ppmvd @ 15% O2

Turbine General Electric Model 7FA		
Distillate Fuel Oil Firing		
Nominal Maximum Electrical Capacity	182.5	MW
Maximum Energy Input	1825	MMBtu/hr (LHV)
	1,926,470,000	kJ/hr
Heat Rate	10,000	Btu/kWh
	10.6	kJ/Wh
NSPS Subpart GG NOx Limit	0.0102%	Volume % NOx @ 15% O2
	102	ppmvd @ 15% O2

Note:

These calculations have been performed using nominal turbine data at 50 degrees F conditions and are intended to provide an estimate of 40 CFR 60 Subpart GG NOx Emission Limits.

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine				
Project Number:	6792-140	Computed by:	M. Lafond	Date:	9/25/00
Subject:	Natural Gas Heater - Emission Calculations	Checked by:	M. Griffin	Date:	10/6/00

Emission Source:	Natural Gas Heater
Source Type:	Natural Gas Fueled Heater
Heat Input (MMBtu/hr):	13
Number of Units:	1
Sulfur Content of Fuel (grains/scf):	0.02
Fuel Heating Value, HHV (Btu/scf):	1020
LHV (Btu/scf):	908
Operating Hours per Year:	3500
Fuel Feed Rate (scf/HR):	12745

Compound	Emission Factor (a)	Emission Rate - per Unit	
		Hourly (b)	Annual (c)
	(Lbs/MMBtu)	(Lbs/Hr)	(Tons/Year)
Criteria Pollutants			
Nitrogen Oxides	0.102	1.3	2.3
Carbon Monoxide	0.09	1.2	2.1
Volatile Organic Carbon	0.06	0.78	1.37
Sulfur Oxides (d)	0.01	0.07	0.13
Particulate	0.01	0.13	0.23

Notes:

(a) Emission Factors based on the information supplied by ENRON on 8/11/99.

(b) Hourly Emission Rate (Lbs/Hr) = (Heat Input * Emission Factor)

(c) Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

(d) Sulfur Oxides Emission Rate (Lbs/Hr) based on the sulfur content of the fuel.

TANKS 4.07 Output and VOC Emissions Calculations for Midway Energy Center, Florida
T001 No. 2 Oil Main Tank

TANKS Ouput:

Maximum Hourly Emission Rate:

Total Hours=	1,000	
July =	744	hours
July Max Fuel Use =	32,551,686	gallons/month
Greatest monthly total standing plus working loss (July) =	1338.29	lb/month
Maximum VOC emission rate =	1.80	lb/hr
Hours each for June, August =	128.00	hours
Fuel use for June, August each =	5,600,290	gallons/month

Annual Total Emission Rate:

Annual total standing plus working losses =	1876.74	lb/year
PTE =	0.9	tons/yr

Tank Specifications Used:

Vertical fixed roof
Vented to atmosphere, default breather vent +/- 0.03 psig
Non-heated
Flat roof
Shell in good condition
43,752,266 gallons/year throughput
2,502,754 gallons capacity

17.4817 turnovers/year Throughput/capacity)
Average liquid height in tank 1/2 tank height

TANKS 4.07 Output and VOC Emissions Calculations for Midway Energy Center, Florida
T002 No. 2 Oil Day Tank

TANKS Ouput:

Maximum Hourly Emission Rate:

Total Hours=	1,000	
July =	744	hours
July Max Fuel =	32,551,686	gallons/month
Greatest monthly total standing plus working loss (July) =	1033.8	lb/month
Maximum VOC emission rate =	1.39	lb/hr
Hours each for June, August =	128.00	hours
Fuel use for June, August each =	5,600,290	gallons/month

Annual Total Emission Rate:

Annual total standing plus working losses =	763.9	lb/year
PTE =	0.38	tons/yr

Tank Specifications Used:

Vertical fixed roof
Vented to atmosphere, default breather vent +/- 0.03 psig
Non-heated
Flat roof
Shell in good condition

43,752,266	gallons/year throughput	6250.3
617,751	gallons capacity	
70.8251	turnovers/year Throughput/capacity)	

Average liquid height in tank 1/2 tank height

Calculations and Computations
HAP Emissions from Simple Cycle CTG Facility

Project:	Florida GE 7FA Turbine				
Project Number:	6792-140	Computed by:	M. Behnke	Date:	9/21/00
Subject:	Natural Gas Turbine Non-Criteria Regulated Pollutant Emissions	Checked by:	M. Griffin	Date:	12/6/00

Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas (lb/10^6scf)	Emission Factor (lb/MMBtu)[d]	Rating	CTG Natural Gas Combustion: Maximum Heat Input, per turbine (MMBtu/Hr)[b]	CTG Natural Gas Combustion: Average Heat Input, per turbine (MMBtu/Hr)[c]	Natural Gas Fired CTG Emissions: Emission Rate, Per Turbine Hourly[e] (lb/hr)	Natural Gas Fired CTG Emissions: Emission Rate, Per Turbine Annual[f] (tpy)	Facility: Emission Rate All CTGs Hourly[j] (lb/hr)	Facility: Emission Rate All CTGs Annual[j] (tpy)	Facility Major Source (Y/N)
1,3-Butadiene	HAP		4.30E-07	D	1,892.6	1,830.4	8.14E-04	1.38E-03	2.44E-03	4.13E-03	No
Acetaldehyde	HAP		4.00E-05	C	1,892.6	1,830.4	7.57E-02	1.28E-01	2.27E-01	3.84E-01	No
Acrolein	HAP		6.40E-06	C	1,892.6	1,830.4	1.21E-02	2.05E-02	3.63E-02	6.15E-02	No
Benzene [g]	HAP	1.36E-02	1.33E-05	B	1,892.6	1,830.4	2.52E-02	4.27E-02	7.57E-02	1.28E-01	No
Ethylbenzene	HAP		3.20E-05	C	1,892.6	1,830.4	6.06E-02	1.03E-01	1.82E-01	3.08E-01	No
Formaldehyde [h]	HAP	2.72E-01	2.66E-04		1,892.6	1,830.4	5.04E-01	8.53E-01	1.51E+00	2.56E+00	No
Naphthalene	HAP		1.30E-06	C	1,892.6	1,830.4	2.46E-03	4.16E-03	7.38E-03	1.25E-02	No
PAHs	HAP		2.20E-06	C	1,892.6	1,830.4	4.16E-03	7.05E-03	1.25E-02	2.11E-02	No
Propylene Oxide	HAP		2.90E-05	D	1,892.6	1,830.4	5.49E-02	9.29E-02	1.65E-01	2.79E-01	No
Toluene [g]	HAP	7.10E-02	6.96E-05	B	1,892.6	1,830.4	1.32E-01	2.23E-01	3.95E-01	6.69E-01	No
Xylene	HAP		6.40E-05	C	1,892.6	1,830.4	1.21E-01	2.05E-01	3.63E-01	6.15E-01	No

	Hours of Operation
Natural Gas CTG	3,500
Number of Turbines	3

	Hourly (lb/hr)	Annual (tpy)	Major Source
Total HAPs	3.0	5.0	No
Maximum Individual HAP	1.5	2.6	No

Natural Gas Heating Value [i] 1020 Btu/SCF (HHV)
908 Btu/SCF (LHV)

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions.
(d) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (1040 Btu/scf)
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (2,500 hr/yr) / (2,000 lb/ton)
(g) Emission Factors from CARB CATEF emission factor database for natural gas fired combustion turbines.
(h) Modified from AP-42 Section 3.1 emissions database for large turbines.
(i) Natural gas heating value is taken from a gas analysis report provided by Duke Energy.

Calculations and Computations

HAP Emissions from Simple Cycle CTG Facility

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: *Natural Gas Turbine Non-Criteria* Regulated Pollutant Emissions

Computed by: M. Behnke **Date:** 9/21/00
Checked by: M. Griffin ***Date:*** 12/6/00

					CTG Natural Gas Combustion		Natural Gas Fired CTG Emissions		Facility		Facility
Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas (lb/10⁶scf)	(lb/MMBtu)[d]	Rating	Maximum Heat Input, per turbine (MMBtu/Hr)[b]	Average Heat Input, per turbine (MMBtu/Hr)[c]	Emission Rate, Per Turbine Hourly[e] (lb/hr)	Annual[f] (tpy)	Emission Rate All CTGs Hourly[e] (lb/hr)	Annual[f] (tpy)	Major Source (Y/N)
1,3-Butadiene	HAP		4.30E-07	D	1,892.6	1,830.4	8.14E-04	9.84E-04	2.44E-03	2.95E-03	No
Acetaldehyde	HAP		4.00E-05	C	1,892.6	1,830.4	7.57E-02	9.15E-02	2.27E-01	2.75E-01	No
Acrolein	HAP		6.40E-06	C	1,892.6	1,830.4	1.21E-02	1.46E-02	3.63E-02	4.39E-02	No
Benzene [g]	HAP	1.36E-02	1.33E-05	B	1,892.6	1,830.4	2.52E-02	3.05E-02	7.57E-02	9.15E-02	No
Ethylbenzene	HAP		3.20E-05	C	1,892.6	1,830.4	6.06E-02	7.32E-02	1.82E-01	2.20E-01	No
Formaldehyde [h]	HAP	2.72E-01	2.66E-04		1,892.6	1,830.4	5.04E-01	6.09E-01	1.51E+00	1.83E+00	No
Naphthalene	HAP		1.30E-06	C	1,892.6	1,830.4	2.46E-03	2.97E-03	7.38E-03	8.92E-03	No
PAHs	HAP		2.20E-06	C	1,892.6	1,830.4	4.16E-03	5.03E-03	1.25E-02	1.51E-02	No
Propylene Oxide	HAP		2.90E-05	D	1,892.6	1,830.4	5.49E-02	6.64E-02	1.65E-01	1.99E-01	No
Toluene [g]	HAP	7.10E-02	6.96E-05	B	1,892.6	1,830.4	1.32E-01	1.59E-01	3.95E-01	4.78E-01	No
Xylene	HAP		6.40E-05	C	1,892.6	1,830.4	1.21E-01	1.46E-01	3.63E-01	4.39E-01	No

	Hours of Operation
Natural Gas CTG	2,500
Number of Turbines	3

	Hourly (lb/hr)	Annual (tpy)	Major Source
Total HAPs	**3.0**	**3.6**	**No**
Maximum Individual HAP	**1.5**	**1.8**	***No***

Natural Gas Heating Value [i] 1020 Btu/SCF (HHV)
908 Btu/SCF (LHV)

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions.
(d) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10⁶ scf) / (1040 Btu/scf)
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (2,000 hr/yr) / (2,000 lb/ton)
(g) Emission Factors from CARB CATEF emission factor database for natural gas fired combustion turbines.
(h) Modified from AP-42 Section 3.1 emissions database for large turbines.
(i) Natural gas heating value is taken from a gas analysis report provided Duke Energy.

Calculations and Computations
HAP Emissions from Simple Cycle CTG Facility

Project:	Florida GE 7FA Turbine				
Project Number:	6792-140	Computed by:	M. Behnke	Date:	9/21/00
Subject:	Distillate Oil-Fired Turbine Non-Criteria Regulated Pollutant Emissions	Checked by:	M. Griffin	Date:	12/6/00

Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine - Distillate Oil (lb/10³gal)	Emission Factor (lb/MMBtu)[d]	Rating	CTG Distillate Oil Combustion: Maximum Heat Input, per turbine (MMBtu/Hr)[b]	CTG Distillate Oil Combustion: Average Heat Input, per turbine (MMBtu/Hr)[c]	Distillate Oil-Fired CTG Emissions: Emission Rate, Per Turbine Hourly[e] (lb/hr)	Distillate Oil-Fired CTG Emissions: Emission Rate, Per Turbine Annual[f] (tpy)	Facility: Emission Rate All CTGs Hourly[e] (lb/hr)	Facility: Emission Rate All CTGs Annual[f] (tpy)	Facility Major Source (Y/N)
1,3-Butadiene	HAP		1.60E-05	D	2,094.1	2,025.0	3.35E-02	1.62E-02	1.01E-01	4.86E-02	No
Benzene	HAP		5.50E-05	C	2,094.1	2,025.0	1.15E-01	5.57E-02	3.46E-01	1.67E-01	No
Formaldehyde	HAP		2.80E-04	B	2,094.1	2,025.0	5.86E-01	2.83E-01	1.76E+00	8.50E-01	No
Naphthalene	HAP		3.50E-05	C	2,094.1	2,025.0	7.33E-02	3.54E-02	2.20E-01	1.06E-01	No
PAHs	HAP		4.00E-05	C	2,094.1	2,025.0	8.38E-02	4.05E-02	2.51E-01	1.21E-01	No
Arsenic	HAP		1.10E-05	D	2,094.1	2,025.0	2.30E-02	1.11E-02	6.91E-02	3.34E-02	No
Beryllium	HAP		3.10E-07	D	2,094.1	2,025.0	6.49E-04	3.14E-04	1.95E-03	9.42E-04	No
Cadmium	HAP		4.80E-06	D	2,094.1	2,025.0	1.01E-02	4.86E-03	3.02E-02	1.46E-02	No
Chromium	HAP		1.10E-05	D	2,094.1	2,025.0	2.30E-02	1.11E-02	6.91E-02	3.34E-02	No
Lead	HAP		1.40E-05	D	2,094.1	2,025.0	2.93E-02	1.42E-02	8.80E-02	4.25E-02	No
Manganese	HAP		7.90E-04	D	2,094.1	2,025.0	1.65E+00	8.00E-01	4.96E+00	2.40E+00	No
Mercury	HAP		1.20E-06	D	2,094.1	2,025.0	2.51E-03	1.21E-03	7.54E-03	3.64E-03	No
Nickel	HAP		4.60E-06	D	2,094.1	2,025.0	9.63E-03	4.66E-03	2.89E-02	1.40E-02	No
Selenium	HAP		2.50E-05	D	2,094.1	2,025.0	5.24E-02	2.53E-02	1.57E-01	7.59E-02	No

	Hours of Operation
Distillate Oil CTG	1,000
Number of Turbines	3

	Hourly (lb/hr)	Annual (tpy)	Major Source
Total HAPs	8.1	3.9	No
Maximum Individual HAP	5.0	2.4	No

Distillate Oil Heating Value 139 MMBtu/10³ gal (HHV)
125 MMBtu/10³ gal (LHV)

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions.
(d) Emission factors from AP-42, Section 3.1, Tables 3.1-4 and 3.1-5.
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (500 hr/yr) / (2,000 lb/ton)

Calculations and Computations

Project:	**Florida GE 7FA Turbine**	**Computed by: L. Sherburne**	**Date: 7/19/00**
Project Number:	**6792-140**	**Checked by: M. Griffin**	**Date: 9/21/00**
Subject:	**Formaldehyde Emission Factor**		

Facility	Manufacturer	Model	Rating (MW)	AP-42 1998 Draft (lb/Mmcuft)	Large Turbines (>70 MW) (lb/Mmcuft)
Gilroy Energy Co./Gilroy, CA	General Electric	Frame 7	87	0.722160	0.722160
Sithe Energies, 32nd St. Naval S/San Diego, CA	General Electric	MS6000	44	0.110160	
SD Gas & Electric Co./San Diego, CA	General Electric	5221	17	0.483480	
Modesto Irrigation District/Mclure/Modesto, CA	General Electric	Frame 7B	50	0.135660	
Willamette Industries, Inc./Oxnard, CA	General Electric	LM2500-PE	67.4	0.044982	
Sycamore Cogen. Co./Bakersfield, CA	General Electric	Frame 7	75	0.085884	0.085884
Calpine / Agnews Cogen./San Jose, CA	General Electric	LM5000	23.33	0.063036	
Dexzel Inc./Bakersfield, CA	General Electric	LM2500	29.1	0.026520	
Procter & Gamble Manufacturing/Sacramento, CA	General Electric	LM2500	20.5	0.088434	
Chevron Inc./Gaviota, CA	Allison	K501	2.5	3.570000	
Ell / Stewart & Stevenson/Berkeley, CA	General Electric	LM2500	25	0.480420	
Calpine Corp./Sumas, WA	General Electric	MS7001EA	87.83	0.006834	0.006834
Sargent Canyon Cogen/Bakersfield, CA	General Electric	Frame 6	42.5	0.059568	
Watsonville Cogen, Partnership/Watsonville, CA	General Electric	LM 2500	24	0.091596	
Southern Cal. Edison Co./Long Beach, CA	Brown-Boveri-Sulzer	11-D	61.75	1.326000	
NR/NR	General Electric	Frame 3	7.7	0.265200	
NR/NR	General Electric	Frame 3	7.7	0.427380	
NR/NR	Solar	T12000	9.4	0.015810	
NR/NR	Solar	T12000	9.4	9.618600	
NR/NR	General Electric	LM1500	10.6	4.273800	
NR/NR	General Electric	LM1500	10.6	25.908000	
Southern Cal. Edison Co./Coolwater, CA	Westinghouse	PACE520	63	38.964000	
Southern Cal. Edison Co./Coolwater, CA	Westinghouse	PACE520	63	0.350880	
Imperial Irrigation D / Choachella/Imperial, CA	General Electric	NS5000P	46.3	0.306000	
Bonneville Pacific Corp./Somis, CA	Solar	Mars	9	0.743580	
WSPA/SWEPI GT/Bakersfield, CA	Allison	501 KB5	4	0.013872	
			Mean (lb/Mmcuft)	3.39	0.27

Note: The AP-42 1998 Draft document calculates the proposed Formaldehyde Emission factor as an average of all of the test data present in the data base. For the purposes of calculating an appropriate emission factor for the Big Cajun One Expansion Project only the data presented for large turbines has been used.

Calculations and Computations
HAP Emissions

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Natural Gas Fuel Heater Non-Criteria Regulated Pollutant Emissions

Computed by: M. Griffin
Checked by:

Pollutant	Type[a]	Emission Factor AP-42 Section 1.4 03/98 - Natural Gas Combustion (lb/10^6 scf)	(lb/MMBtu)[b]	Rating	Auxiliary Boiler Natural Gas Combustion: Maximum Heat Input, per boiler (MMBtu/Hr)	Averge Heat Input, per boiler (MMBtu/Hr)	Auxiliary Boiler Emissions: Emission Rate, Hourly[c] (lb/hr)	Annual[d] (tpy)	Facility Emission Rate: Hourly[c] (lb/hr)	Annual[d] (tpy)	Facility Major Source (Y/N)
1,3-Butadiene	HAP				13	13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	No
2-Methylnaphthalene	HAP	2.40E-05	2.35E-08	D	13	13	3.06E-07	5.35E-07	3.06E-07	5.35E-07	No
3-Methylchloranthrene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
7,12-Dimethylbenz(a)anthracene	HAP	1.60E-05	1.57E-08	E	13	13	2.04E-07	3.57E-07	2.04E-07	3.57E-07	No
Acenaphthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Acenaphthylene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Anthracene	HAP	2.40E-06	2.35E-09	E	13	13	3.06E-08	5.35E-08	3.06E-08	5.35E-08	No
Benz(a)anthracene	HAP	1.80E-06	1.76E-09		13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Benzene	HAP	2.10E-03	2.06E-06	B	13	13	2.68E-05	4.68E-05	2.68E-05	4.68E-05	No
Benzo(a)pyrene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Benzo(b)flouoranthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Benzo(g,h,I)perylene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Benzo(k)fluoranthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Chrysene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Dibenzo(a,h)anthracene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Dichlorobenzene	HAP	1.20E-03	1.18E-06	E	13	13	1.53E-05	2.68E-05	1.53E-05	2.68E-05	No
Fluoranthene	HAP	3.00E-06	2.94E-09	E	13	13	3.82E-08	6.69E-08	3.82E-08	6.69E-08	No
Fluorene	HAP	2.80E-06	2.75E-09	E	13	13	3.57E-08	6.25E-08	3.57E-08	6.25E-08	No
Formaldehyde	HAP	7.50E-02	7.35E-05	B	13	13	9.56E-04	1.67E-03	9.56E-04	1.67E-03	No
Hexane	HAP	1.80E+00	1.76E-03		13	13	2.29E-02	4.01E-02	2.29E-02	4.01E-02	No
Indeno(1,2,3-cd)pyrene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Naphthalene	HAP	6.10E-04	5.98E-07	E	13	13	7.77E-06	1.36E-05	7.77E-06	1.36E-05	No
Phenanathrene	HAP	1.70E-05	1.67E-08	D	13	13	2.17E-07	3.79E-07	2.17E-07	3.79E-07	No
Pyrene	HAP	5.00E-06	4.90E-09	E	13	13	6.37E-08	1.12E-07	6.37E-08	1.12E-07	No
Toluene	HAP	3.40E-03	3.33E-06	C	13	13	4.33E-05	7.58E-05	4.33E-05	7.58E-05	No
Arsenic	HAP	2.00E-04	1.96E-07	E	13	13	2.55E-06	4.46E-06	2.55E-06	4.46E-06	No
Barium	HAP	4.40E-03	4.31E-06	D	13	13	5.61E-05	9.81E-05	5.61E-05	9.81E-05	No
Beryllium	HAP	1.20E-05	1.18E-08	E	13	13	1.53E-07	2.68E-07	1.53E-07	2.68E-07	No
Cadmium	HAP	1.10E-03	1.08E-06	D	13	13	1.40E-05	2.45E-05	1.40E-05	2.45E-05	No
Chromium	HAP	1.40E-03	1.37E-06	D	13	13	1.78E-05	3.12E-05	1.78E-05	3.12E-05	No
Cobalt	HAP	8.40E-05	8.24E-08	D	13	13	1.07E-06	1.87E-06	1.07E-06	1.87E-06	No
Copper	HAP	8.50E-04	8.33E-07	C	13	13	1.08E-05	1.90E-05	1.08E-05	1.90E-05	No
Lead	HAP	5.00E-04	4.90E-07	D	13	13	6.37E-06	1.12E-05	6.37E-06	1.12E-05	No
Manganese	HAP	3.80E-04	3.73E-07	D	13	13	4.84E-06	8.48E-06	4.84E-06	8.48E-06	No
Mercury	HAP	2.60E-04	2.55E-07	D	13	13	3.31E-06	5.80E-06	3.31E-06	5.80E-06	No
Molybdenum	HAP	1.10E-03	1.08E-06	D	13	13	1.40E-05	2.45E-05	1.40E-05	2.45E-05	No
Nickel	HAP	2.10E-03	2.06E-06	C	13	13	2.68E-05	4.68E-05	2.68E-05	4.68E-05	No
Selenium	HAP	2.40E-05	2.35E-08	E	13	13	3.06E-07	5.35E-07	3.06E-07	5.35E-07	No
Vanadium	HAP	2.30E-03	2.25E-06	D	13	13	2.93E-05	5.13E-05	2.93E-05	5.13E-05	No
Zinc	HAP	2.90E-02	2.84E-05	E	13	13	3.70E-04	6.47E-04	3.70E-04	6.47E-04	No

Hours of Operation
Auxiliary Boiler 3,500
Number of Auxiliary Boilers per Facility 1

Natural Gas Heating Value 1020 Btu/SCF (HHV)

	Hourly	Annual	Major Source
Facility Total HAPs	**0.02**	**0.04**	**No**
Maximum Individual HAP	**0.02**	**0.04**	**No**

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (1,020 Btu/scf)
(c) Hourly Emission Rate (lb/hr) = [Heat Input (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(d) Annual Emission Rate (tpy) = (Hourly Emission Rate, lb/hr) * (8,760 hr/yr) / (2,000 lb/ton)

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification

User Identification:	T001 July
City:	Midway
State:	Florida
Company:	MIdway Energy Center
Type of Tank:	Vertical Fixed Roof Tank
Description:	MAIN TANK

Tank Dimensions

Shell Height (ft):	47.40
Diameter (ft):	94.80
Liquid Height (ft):	47.40
Avg. Liquid Height (ft):	24.00
Volume (gallons):	2,502,753.60
Turnovers:	17.48
Net Throughput (gal/yr):	43,752,266.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	94.80

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Miami, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jun	80.68	76.33	85.04	75.91	0.0125	0.0109	0.0143	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jul	81.34	76.83	85.86	75.91	0.0127	0.0111	0.0146	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Aug	81.35	77.02	85.68	75.91	0.0127	0.0112	0.0145	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):						49.4027	54.0242	51.5327				
Vapor Space Volume (cu ft):						211,063.0655	211,063.0655	211,063.0655				
Vapor Density (lb/cu ft):						0.0003	0.0003	0.0003				
Vapor Space Expansion Factor:						0.0284	0.0295	0.0281				
Vented Vapor Saturation Factor:						0.9806	0.9802	0.9802				
Tank Vapor Space Volume												
Vapor Space Volume (cu ft):						211,063.0655	211,063.0655	211,063.0655				
Tank Diameter (ft):						94.8000	94.8000	94.8000				
Vapor Space Outage (ft):						29.9024	29.9024	29.9024				
Tank Shell Height (ft):						47.4000	47.4000	47.4000				
Average Liquid Height (ft):						24.0000	24.0000	24.0000				
Roof Outage (ft):						6.5024	6.5024	6.5024				
Roof Outage (Dome Roof)												
Roof Outage (ft):						6.5024	6.5024	6.5024				
Dome Radius (ft):						94.8000	94.8000	94.8000				
Shell Radius (ft):						47.4000	47.4000	47.4000				
Vapor Density												
Vapor Density (lb/cu ft):						0.0003	0.0003	0.0003				
Vapor Molecular Weight (lb/lb-mole):						130.0000	130.0000	130.0000				
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):						0.0125	0.0127	0.0127				
Daily Avg. Liquid Surface Temp. (deg. R):						540.3530	541.0146	541.0194				
Daily Average Ambient Temp. (deg. F):						81.3500	82.6000	82.8500				
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):						10.731	10.731	10.731				
Liquid Bulk Temperature (deg. R):						535.5817	535.5817	535.5817				
Tank Paint Solar Absorptance (Shell):						0.1700	0.1700	0.1700				
Tank Paint Solar Absorptance (Roof):						0.1700	0.1700	0.1700				
Daily Total Solar Insulation Factor (Btu/sqft day):						1,771.0011	1,854.1259	1,775.7602				
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:						0.0284	0.0295	0.0281				
Daily Vapor Temperature Range (deg. R):						17.4300	18.0416	17.3086				
Daily Vapor Pressure Range (psia):						0.0033	0.0035	0.0034				
Breather Vent Press. Setting Range(psia):						0.0600	0.0600	0.0600				
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):						0.0125	0.0127	0.0127				
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):						0.0109	0.0111	0.0112				
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):						0.0143	0.0146	0.0145				
Daily Avg. Liquid Surface Temp. (deg R):						540.3530	541.0146	541.0194				
Daily Min. Liquid Surface Temp. (deg R):						535.9955	536.5042	536.6922				
Daily Max. Liquid Surface Temp. (deg R):						544.7105	545.5250	545.3465				
Daily Ambient Temp. Range (deg. R):						12.5000	12.8000	12.3000				
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:						0.9806	0.9802	0.9802				
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):						0.0125	0.0127	0.0127				
Vapor Space Outage (ft):						29.9024	29.9024	29.9024				

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Working Losses (lb):	216.5387	1,284.2609	220.9801
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0125	0.0127	0.0127
Net Throughput (gal/mo.):	5,600,290.000 0	32,551,686.00 00	5,600,290.000 0
Number of Turnovers:	17.4817	17.4817	17.4817
Turnover Factor:	1.0000	1.0000	1.0000
Maximum Liquid Volume (cuft):	2,502,753.595 7	2,502,753.595 7	2,502,753.595 7
Maximum Liquid Height (ft):	47.4000	47.4000	47.4000
Tank Diameter (ft):	94.8000	94.8000	94.8000
Working Loss Product Factor:	1.0000	1.0000	1.0000
Total Losses (lb):	265.9414	1,338.2852	272.5128

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January , February , March , April , May , June , July , August , September , October , November , December

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	1,721.78	154.96	1,876.74

TANKS 4.0
Emissions Report - Detail Format
Tank Identification and Physical Characteristics

Identification	
User Identification:	T002 July
City:	Midway
State:	Florida
Company:	Midway Energy Center
Type of Tank:	Vertical Fixed Roof Tank
Description:	DAY TANK
Tank Dimensions	
Shell Height (ft):	29.70
Diameter (ft):	59.50
Liquid Height (ft):	29.70
Avg. Liquid Height (ft):	24.00
Volume (gallons):	617,751.00
Turnovers:	70.83
Net Throughput (gal/yr):	43,752,276.48
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft):	0.00
Radius (ft) (Dome Roof):	94.80
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.03

Meteorological Data used in Emissions Calculations: Miami, Florida (Avg Atmospheric Pressure = 14.75 psia)

TANKS 4.0
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jun	80.68	76.33	85.04	75.91	0.0125	0.0109	0.0143	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Jul	81.34	76.83	85.86	75.91	0.0127	0.0111	0.0146	130.0000			188.00	Option 5: A=12.101, B=8907
Distillate fuel oil no. 2	Aug	81.35	77.02	85.68	75.91	0.0127	0.0112	0.0145	130.0000			188.00	Option 5: A=12.101, B=8907

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):						5.3573	5.8602	5.5899				
Vapor Space Volume (cu ft):						22,564.3340	22,564.3340	22,564.3340				
Vapor Density (lb/cu ft):						0.0003	0.0003	0.0003				
Vapor Space Expansion Factor:						0.0284	0.0295	0.0281				
Vented Vapor Saturation Factor:						0.9947	0.9945	0.9945				
Tank Vapor Space Volume												
Vapor Space Volume (cu ft):						22,564.3340	22,564.3340	22,564.3340				
Tank Diameter (ft):						59.5000	59.5000	59.5000				
Vapor Space Outage (ft):						8.1152	8.1152	8.1152				
Tank Shell Height (ft):						29.7000	29.7000	29.7000				
Average Liquid Height (ft):						24.0000	24.0000	24.0000				
Roof Outage (ft):						2.4152	2.4152	2.4152				
Roof Outage (Dome Roof)												
Roof Outage (ft):						2.4152	2.4152	2.4152				
Dome Radius (ft):						94.8000	94.8000	94.8000				
Shell Radius (ft):						29.7500	29.7500	29.7500				
Vapor Density												
Vapor Density (lb/cu ft):						0.0003	0.0003	0.0003				
Vapor Molecular Weight (lb/lb-mole):						130.0000	130.0000	130.0000				
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):						0.0125	0.0127	0.0127				
Daily Avg. Liquid Surface Temp. (deg. R):						540.3530	541.0146	541.0194				
Daily Average Ambient Temp. (deg. F):						81.3500	82.6000	82.8500				
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):						10.731	10.731	10.731				
Liquid Bulk Temperature (deg. R):						535.5817	535.5817	535.5817				
Tank Paint Solar Absorptance (Shell):						0.1700	0.1700	0.1700				
Tank Paint Solar Absorptance (Roof):						0.1700	0.1700	0.1700				
Daily Total Solar Insulation Factor (Btu/sqft day):						1,771.0011	1,854.1259	1,775.7602				
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:						0.0284	0.0295	0.0281				
Daily Vapor Temperature Range (deg. R):						17.4300	18.0416	17.3086				
Daily Vapor Pressure Range (psia):						0.0033	0.0035	0.0034				
Breather Vent Press. Setting Range(psia):						0.0600	0.0600	0.0600				
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):						0.0125	0.0127	0.0127				
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):						0.0109	0.0111	0.0112				
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):						0.0143	0.0146	0.0145				
Daily Avg. Liquid Surface Temp. (deg R):						540.3530	541.0146	541.0194				
Daily Min. Liquid Surface Temp. (deg R):						535.9955	536.5042	536.6922				
Daily Max. Liquid Surface Temp. (deg R):						544.7105	545.5250	545.3465				
Daily Ambient Temp. Range (deg. R):						12.5000	12.8000	12.3000				
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:						0.9947	0.9945	0.9945				
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):						0.0125	0.0127	0.0127				
Vapor Space Outage (ft):						8.1152	8.1152	8.1152				

TANKS 4.0
Emissions Report - Detail Format
Detail Calculations (AP-42)- (Continued)

Working Losses (lb):	127.8109	758.0290	130.4325
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0125	0.0127	0.0127
Net Throughput (gal/mo.):	5,600,290.000 0	32,551,686.00 00	5,600,290.000 0
Number of Turnovers:	70.8251	70.8251	70.8251
Turnover Factor:	0.5902	0.5902	0.5902
Maximum Liquid Volume (cuft):	617,751.0019	617,751.0019	617,751.0019
Maximum Liquid Height (ft):	29.7000	29.7000	29.7000
Tank Diameter (ft):	59.5000	59.5000	59.5000
Working Loss Product Factor:	1.0000	1.0000	1.0000
Total Losses (lb):	133.1683	763.8892	136.0224

TANKS 4.0
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January , February , March , April , May , June , July , August , September , October , November , December

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	1,016.27	16.81	1,033.08

TANKS 4.0
Emissions Report - Detail Format
Total Emissions Summaries - All Tanks in Report

Emissions Report for: January , February , March , April , May , June , July , August , September , October , November , December

Tank Identification				Losses (lbs)
T001 July	MIdway Energy Center	Vertical Fixed Roof Tank	Midway, Florida	1,876.74
T002 July	Midway Energy Center	Vertical Fixed Roof Tank	MIdway, Florida	1,033.08
Total Emissions for all Tanks:				2,909.82

APPENDIX C

BACT SUPPORTING INFORMATION

EPA United States Environmental Protection Agency REGION 2 New Jersey, New York, Puerto Rico & U.S. Virgin Islands

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EPA INTENDS TO MAKE CHANGES TO DRAFT PREPA RE-POWERING PERMIT

FOR RELEASE: Thursday, January 20, 2000

(#00015) San Juan, Puerto Rico – In response to public concerns and new information about the best way to control nitrogen oxide emissions from oil-fired power plants, the **U.S. Environmental Protection Agency (EPA) intends to make changes to a proposed permit for the Puerto Rico Electric Power Authority's (PREPA) re-powering project** in San Juan. The draft permit, **released in March 1999**, would allow PREPA to increase the electric generating capacity at its San Juan Power Plant and lower total emissions by replacing two, decades-old, 44 megawatt boilers with two 232-megawatt combined cycle turbines. **The intended changes to the draft permit will require PREPA to replace one of the two nitrogen control technologies proposed for installation on the new turbines with special burners to be installed on four old boilers that will remain in service.** While this change will increase nitrogen oxide emissions over the levels under the original draft permit, the emissions will still be at lower levels than those from the old plant.

"An additional benefit of making this change in the control technology requirement is that there will be a decrease, from the original proposed permit, in two pollutants of particular concern in the San Juan area – sulfuric acid mist and fine particles," said Jeanne M. Fox, EPA Region 2 Administrator.

In its draft permit, proposed in March 1999, EPA included Selective Catalytic Reduction (SCR), which uses an ammonia injection system to reduce nitrogen oxide emissions, and steam injection. However, new data indicate that, on oil-fired turbines, SCR cannot consistently achieve the expected reductions in nitrogen oxide emissions. As a result, EPA is removing the SCR requirement and will instead require PREPA to install special burners, called "low NOx burners," on the four old boilers at its facility. PREPA would still use steam injection on its turbines.

"After carefully considering the feasibility of using SCR on an oil-fired plant and reviewing public comments, the choice was clear," said Jeanne M. Fox, EPA Regional Administrator. "We want to ensure that PREPA uses the most reliable pollution controls. Steam injection systems and low NOx burners are both tried and true nitrogen oxide controls."

For more information contact:

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Table C-1
PRICE QUOTE ADJUSTMENTS
Midway Energy Center
General Electric 7 FA Turbine

NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA - Proposed option with DLN to 9 ppm

	Hours of Operation
3,500	
$3,010,000	Budgetary cost for SCR (without auxiliaries)[1]
$1,440,000	Catalyst Support Structure
$1,570,000	Catalyst Bed
$3,010,000	Budgetary cost for SCR (without auxiliaries)
$50,000	Transition = Transition piece , stainless steel, spool piece, = $50k
$20,000	Crane = Crane to handle modules = $20k
$100,000	Auxiliaries not included in Engelhard quote = ($10k per tank + $20K insulation and heating + $20k pumps, piping flow meters, safety equipment) x 2 tanks = $100k
$30,000	Fan = Dilution air fan, variable speed drive, ductwork, starter = $30k
$523,000	Spare Catalyst = 1 spare catalyst on site at all times for 3 turbines
$3,733,000	

Carbon Monoxide High Temperature Oxidation Catalyst - Top Control Option
Simple Cycle, General Electric 7 FA, Baseline and Proposed Control Option

$900,000	Budgetary cost for CO catalyst (without auxililiaries)[1]
$210,000	Catalyst Support Structure
$680,000	Catalyst Bed
$900,000	Oxidation System (catalyst and structure)
$50,000	Transition = Transition piece , stainless steel, spool piece, = $50k
$20,000	Crane = Crane to handle modules = $20k
$30,000	Fan = Dilution air fan, variable speed drive, ductwork, starter = $30k
$227,000	Spare Catalyst = 1 spare catalyst on site at all times for 3 turbines
$1,227,000	

[1]The 12/13/99 Engelhard quote was provided for a combined CO oxidation and SCR system.
The original quotation has been adjusted for separate oxidation and SCR systems.
The original quotation has also been escalated to reflect current control system costs using the Vatavuk Air Pollution Control Cost Indexes per OAQPS control cost manual.
The original quotation has also been used to estimate catalyst costs for differing operating scenarios.

Table C-1A
Midway Energy Center
General Electric 7 FA Turbine
Control Equipment Cost Adjustment

Budgetary Cost	Costs from Engelhard Quote
Turbine Operation (hrs/year)	3,500
Base Exhaust Air Flow (lb/hr)	3,900,000
Actual Exhaust Air Flow (lb/hr)	3,642,000
Original Quotation Costs [1]	
Total System (SCR & Oxidation Catalyst)	3,678,000
Replacement CO	643,000
Replacement ZNX	1,479,000
Support Equipment Cost	1,556,000
Total Catalyst Cost	2,122,000
Catalyst Cost/Total Cost	57.7%
SCR System Only [2]	
SCR Costs from 12/13/99 Quote	
Cost Index [3]	105.7
SCR Support Equipment	1,356,000
SCR Catalyst Cost	1,479,000
SCR Total Cost	2,835,000
Escalated Cost for June 2000	
Cost Index [3]	112.3
SCR Support Equipment	1,440,000
SCR Catalyst Cost	1,570,000
SCR Total Cost	3,010,000
Oxidation Catalyst System only [2]	
Costs from 11/13/98 Quote	
Cost Index [3]	105.7
OxCat Support Equipment	200,000
OxCat Catalyst Cost	643,000
OxCat Total Cost	843,000
Escalated Cost for June 2000	
Cost Index [3]	112.3
OxCat Support Equipment	210,000
OxCat Catalyst Cost	680,000
OxCat Total Cost	900,000

Notes:
1 - From original Engelhard quotation, December 13, 1999 provided by Jeff Koerner of FL DEP.
2 - Original quotation was provided for a combined SCR/Oxidation Catalyst System. For BACT analysis costs have been separated.
3 - Vatavuk Air Pollution Control Cost Index for Catalytic Incinerators. Base index fourth quarter 1999, Escalated index 2nd quarter 2000.

TABLE C-2
Midway Energy Center
NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	61%

Facility Input Data

Item	Value
Operating Schedule	Assumed 8 hours per shift
Total Hours per year	3,500
Natural Gas Firing (Normal Operation)	2,500
Distillate Oil Firing (Normal Operation)	1,000
Source(s) Controlled	One Power Block, 175 MW
NOx From Normal Natural Gas Operation (lb/hr)[1]	59.6
NOx From Distillate Oil Operation (lb/hr)	321.0
NOx From Source(s) (tpy)	235.0
Site Specific Enclosure (Building) Cost	NA
Site Specific Electricity Value ($/kWh)	0.10
Site Specific Natural Gas Cost ($/MMBtu)	NA
Site Specific Operating Labor Cost ($/hr)	30
Site Specific Maint. Labor Cost ($/hr)	30

[1]NOx emissions are based on data at 100% load and intake air chilled to maximum of 50°F.

Capital Costs[1]

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$3,733,000	Engelhard Quote plus auxiliaries, A
b.) Instrumentation	$373,300	0.10 x A
c.) Sales taxes	$224,000	0.06 x A
d.) Freight	$186,700	0.05 x A
Total Purchased equipment cost, (PEC)	$4,517,000	B = 1.21 x A
2.) Direct installation costs		
a.) Foundations and supports	$361,400	0.08 x B
b.) Handling and erection	$632,400	0.14 x B
c.) Electrical	$180,700	0.04 x B
d.) Piping	$90,300	0.02 x B
e.) Insulation for ductwork	$45,200	0.01 x B
f.) Painting	$45,200	0.01 x B
Total direct installation cost	$1,355,200	0.30 x B
3.) Site preparation, SP	NA	NA
4.) Buildings, Bldg	NA	NA
Total Direct Cost, DC	$5,872,200	1.30B + SP + Bldg
Indirect Costs (installation)		
5.) Engineering	$451,700	0.10 x B
6.) Construction and field expenses	$225,900	0.05 x B
7.) Contractor fees	$451,700	0.10 x B
8.) Start-up	$90,300	0.02 x B
9.) Performance test	$45,200	0.01 x B
10.) Contingencies	$135,500	0.03 x B
Total Indirect Cost, IC	$1,400,300	0.28B
Total Capital Investment (TCI) = DC + IC	***$7,272,500***	***1.58B + SP + Bldg***

1 See Appendix C, Tables C-1 and C-1A

TABLE C-2
Midway Energy Center
NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	61%

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Catalyst Press. Drop (in. W.C.)	4.2	Pressure drop - catalyst bed	Vendor, estimate
Power Output of Turbine (kW)	175,000	Output at Average Conditions	
Power Loss Due to Pressure Drop (%)	0.44%	0.105% for every 1" pressure drop	Vendor
Power Loss Due to Pressure Drop (kW)	772		
Unit Cost ($/kW-hr)	$0.10	Estimated Market Value	Estimate
Cost of Heat Rate Loss ($)	$270,110		
Fan for Ambient Air Cooling (kW)	75	Estimated from Cooling Air Requirements	
Energy Required for Fan (kWh)	262,500		
Unit Cost ($/kW-hr)	$0.10	Estimated Market Value	Estimate
Cost of Cooling Fan Power ($)	$26,250		
Total Electricity Cost ($)	$296,360		
2) Operating Labor			
SCR Requirement (hr/yr)	218.75	1/2 hr/shift, 3,500 hours per year	Estimate
Ammonia Delivery Requirement (hr/yr)	24	3 deliveries per year, 8 hr/delivery	Estimate
Ammonia Recordkeeping/Reporting (hr/yr)	40.0	One week of reporting	Estimate
Catalyst Cleaning (hr/yr)	80.0	2 workers x 40 hours per year	
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Cost ($/yr)	$10,883		
3) Supervisory Labor			
Cost ($/yr)	$1,630	15% Operating Labor	OAQPS
4) Maintenance			
SCR Labor Req. (hr/yr)	218.75	1/2 hour per shift	OAQPS
Catalyst Replacement Labor Req. (hr/yr)	106.7	8 workers, 40 hours every 3 yrs	Estimate
Ammonia System Maintenance Labor Req. (hr/yr)	365.0	1 hr/day, 365 day/yr	Estimate
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Labor Cost ($/yr)	$20,713		
Material Cost ($/yr)	$20,710	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$41,420		
5) Ammonia Requirement			
Requirement (ton/yr)	78	Ammonia requirement, 0.5436 lb NH3/lb NOx Removed	Vendor
Unit Cost ($/ton)	$315	For pure ammonia	Chemical Market Reporter
Total Cost ($/yr)	$24,590		
6) Process Air			
Requirement (scf/lb NH3)	350		Vendor
Requirement (Mscf/yr)	54,647		Vendor
Unit Cost ($/Mscf)	$0.20	Peters and Timmerhaus	Standard
Total Cost ($/yr)	$10,930		
7) Catalyst Replacement			
Catalyst Cost ($)	$1,570,000	Catalyst modules	Vendor
Catalyst Disposal Cost ($)	$50,000	Disposal of catalyst modules	Estimate
Sales Tax ($)	$78,500	5% sales tax in Indiana	Estimate
Catalyst Life (yrs)	3	n	OAQPS
Interest Rate (%)	7	i	
CRF	0.381	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$647,220	(Volume)(Unit Cost)(CRF)	
8) Indirect Annual Costs			
Overhead	$32,400	60% of O&M Costs	OAQPS
Administration	$145,500	2% of Total Capital Investment	OAQPS
Property Tax	$72,730	1% of Total Capital Investment	OAQPS
Insurance	$72,730	1% of Total Capital Investment	OAQPS
Capital Recovery	$805,700	10 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	$1,129,060		
Total Annualized Cost ($/yr)	**$2,162,100**		
Total NOx Controlled (tpy)	**143.6**		
Cost Effectiveness ($/ton)	**$15,100**		

ENGELHARD

Best Available Copy

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

7FA – Simple Cycle

ASSUMED AMBIENT	59	59
GIVEN TURBINE EXHAUST TEMPERATURE, F	1,100	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr	3,900,000	4,080,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23	71.63
O2	12.61	11.04
CO2	3.63	5.20
H2O	7.60	11.20
Ar	0.93	0.93
AMBIENT AIR FLOW, lb/hr	332,949	348,316
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	4,232,949	4,428,316
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.70	72.37
O2	13.09	11.64
CO2	3.35	4.80
H2O	7.01	10.33
Ar	0.86	0.86
CALCULATED AIR + GAS MOL. WT.	28.48	28.32
GIVEN: TURBINE CO, ppmvd	9.0	20.0
CALC.: TURBINE CO, lb/hr	31.9	71.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	9.0	42.0
CALC.: TURBINE NOx, lb/hr	64.5	355.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE	7.1	13.6
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE	8.8	41.0
FLUE GAS TEMP. @ SCR CATALYST, F	1,025	1,025
DESIGN REQUIREMENTS		
CO CATALYST CO CONVERSION, %	90%	90%
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.6	ADVISE
NH3 SLIP, ppmvd @ 15% O2	9	12
SCR PRESSURE DROP, 4.0"WG – Nom.		
GUARANTEED PERFORMANCE DATA		
CO CONVERSION - % Min.	90.0%	90.0%
CO OUT, ppmvd @ 15% O2	0.7	1.4
CO OUT, lb/hr	3.2	7.2
CO PRESSURE DROP	2.2	2.4
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%
NOx OUT, lb/hr – Max.	25.1	138.1
NOx OUT, ppmvd@15%O2 – Max.	3.4	16.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	139	424
NH3 SLIP, ppmvd@15%O2 – Max.	9	12
SCR PRESSURE DROP, "WG - Max.	4.2	4.4
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft	1650.0	
CO SYSTEM	$843,000	
REPLACEMENT CO CATALYST MODULES	$643,000	
SCR SYSTEM	$2,835,000	
REPLACEMENT SCR CATALYST MODULES	$1,479,000	

Post-it® Fax Note 7671

To	Mike Griffin	From	Jeff Koerner
Co./Dept.	ENSR	Co.	DEP/NSR Section
Phone #	978/635-9500	Phone #	850/414-7268
Fax #	978/635-9180	Fax #	850/922-6979
Date	11-27-00	# of pages	1

Mike,
Check out the "Peace River" Technical Evaluation on our web site.
Jeff

APPENDIX D

BPIP MODEL OUTPUT FILE

BPIP (Dated: 95086)

DATE : 10/24/ 0
TIME : 8:14:43
C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

==========================
BPIP PROCESSING INFORMATION:
==========================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

The UTMP variable is set to UTMY. The input is assumed to be in UTM coordinates. BPIP will move the UTM origin to the first pair of UTM coordinates read. The UTM coordinates of the new origin will be subtracted from all the other UTM coordinates entered to form this new local coordinate system.

Plant north is set to 0.00 degrees with respect to True North.

C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
STCK1	24.38	0.00	41.15	65.00
STCK2	24.38	0.00	41.15	65.00
STCK3	24.38	0.00	41.15	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 10/24/ 0

TIME : 8:14:43

C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

BPIP output is in meters

SO BUILDHGT STCK1	8.23	8.23	8.23	8.23	8.23	8.23
SO BUILDHGT STCK1	13.72	13.72	13.72	13.72	13.72	8.23
SO BUILDHGT STCK1	8.23	8.23	8.23	8.23	8.23	8.23
SO BUILDHGT STCK1	8.23	8.23	8.23	8.23	8.23	8.23
SO BUILDHGT STCK1	16.46	16.46	16.46	16.46	16.46	16.46
SO BUILDHGT STCK1	16.46	16.46	16.46	8.23	8.23	8.23
SO BUILDWID STCK1	20.84	21.37	21.25	20.48	19.09	17.12
SO BUILDWID STCK1	18.53	15.68	14.31	15.68	17.84	17.12
SO BUILDWID STCK1	19.09	20.48	21.25	21.37	20.84	19.68
SO BUILDWID STCK1	20.84	21.37	21.25	20.48	19.09	17.12
SO BUILDWID STCK1	16.57	15.68	14.31	15.68	16.57	16.79
SO BUILDWID STCK1	16.69	16.63	15.52	21.37	20.84	19.68

SO BUILDHGT STCK2	8.23	14.67	14.67	14.67	14.67	14.67
SO BUILDHGT STCK2	13.72	13.72	13.72	13.72	13.72	8.23
SO BUILDHGT STCK2	8.23	8.23	8.23	8.23	8.23	0.00
SO BUILDHGT STCK2	8.23	8.23	13.72	16.46	16.46	16.46
SO BUILDHGT STCK2	16.46	16.46	16.46	16.46	16.46	16.46
SO BUILDHGT STCK2	16.46	16.46	13.75	8.23	8.23	0.00
SO BUILDWID STCK2	21.29	57.40	58.82	60.67	60.67	58.82
SO BUILDWID STCK2	18.07	15.48	14.11	15.48	18.13	17.36
SO BUILDWID STCK2	19.39	20.84	21.65	21.80	21.29	0.00
SO BUILDWID STCK2	20.84	21.37	16.12	16.20	16.84	16.96
SO BUILDWID STCK2	16.39	15.48	14.11	15.48	16.39	17.34
SO BUILDWID STCK2	17.25	16.63	15.03	21.80	21.29	0.00

SO BUILDHGT STCK3	8.23	8.23	14.67	14.67	14.67	14.67
SO BUILDHGT STCK3	14.67	14.67	14.67	13.75	13.75	8.23
SO BUILDHGT STCK3	8.23	8.23	8.23	8.23	8.23	0.00
SO BUILDHGT STCK3	8.23	8.23	14.67	16.46	16.46	16.46
SO BUILDHGT STCK3	16.46	16.46	16.46	16.46	16.46	8.23
SO BUILDHGT STCK3	8.23	13.72	13.72	13.72	13.72	0.00
SO BUILDWID STCK3	21.67	22.08	58.82	60.67	60.67	58.82
SO BUILDWID STCK3	57.40	60.16	61.08	15.95	17.98	17.19
SO BUILDWID STCK3	19.33	20.89	21.82	22.08	21.67	0.00
SO BUILDWID STCK3	21.29	21.80	58.82	16.07	16.69	16.79
SO BUILDWID STCK3	16.90	15.95	14.51	15.95	16.90	17.19
SO BUILDWID STCK3	19.33	39.62	41.31	41.74	40.90	0.00

BPIP (Dated: 95086)

DATE : 10/24/ 0
TIME : 8:14:43
C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

The UTMP variable is set to UTMY. The input is assumed to be in UTM coordinates. BPIP will move the UTM origin to the first pair of UTM coordinates read. The UTM coordinates of the new origin will be subtracted from all the other UTM coordinates entered to form this new local coordinate system.

The new local coordinates will be displayed in parentheses just below the UTM coordinates they represent.

Plant north is set to 0.00 degrees with respect to True North.

==============
INPUT SUMMARY:
==============

Number of buildings to be processed : 16

EXHDUCT1 has 1 tier(s) with a base elevation of 0.00 Meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER X	COORDINATES Y
EXHDUCT1	1	1	8.23	4		
					556674.30	3028588.23 meters
					(0.00	0.00) meters
					556693.98	3028588.23 meters
					(19.68	0.00) meters
					556693.98	3028579.82 meters
					(19.68	-8.41) meters
					556674.30	3028579.82 meters
					(0.00	-8.41) meters

EXHDUCT2 has 1 tier(s) with a base elevation of 0.00 Meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER X	COORDINATES Y
EXHDUCT2	1	5	8.23	4		
					556674.30	3028552.00 meters

```
                                          (         0.00        -36.24) meters
                                             556694.44  3028552.00 meters
                                          (        20.14        -36.24) meters
                                             556694.44  3028543.58 meters
                                          (        20.14        -44.65) meters
                                             556674.30  3028543.58 meters
                                          (         0.00        -44.65) meters


EXHDUCT3 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

EXHDUCT3    1        9      8.23     4
                                             556674.30  3028515.29 meters
                                          (         0.00        -72.94) meters
                                             556694.91  3028515.29 meters
                                          (        20.60        -72.94) meters
                                             556694.91  3028507.34 meters
                                          (        20.60        -80.89) meters
                                             556674.30  3028507.34 meters
                                          (         0.00        -80.89) meters


TURBENC2 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

TURBENC2    1       13     13.72     4
                                             556694.51  3028551.33 meters
                                          (        20.21        -36.90) meters
                                             556708.22  3028551.33 meters
                                          (        33.92        -36.90) meters
                                             556708.22  3028543.65 meters
                                          (        33.92        -44.59) meters
                                             556694.51  3028543.65 meters
                                          (        20.21        -44.59) meters


TURBENC3 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

TURBENC3    1       17     13.75     4
                                             556694.91  3028514.83 meters
                                          (        20.60        -73.40) meters
                                             556708.09  3028514.83 meters
                                          (        33.79        -73.40) meters
                                             556708.09  3028507.61 meters
                                          (        33.79        -80.63) meters
                                             556694.91  3028507.61 meters
                                          (        20.60        -80.63) meters


AIRINT2  has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y
```

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER COORDINATES X	Y
AIRINT2	1	21	16.46	4		
					556708.36	3028554.58 meters
					(34.05	-33.65) meters
					556717.50	3028554.58 meters
					(43.19	-33.65) meters
					556717.50	3028540.47 meters
					(43.19	-47.77) meters
					556708.36	3028540.47 meters
					(34.05	-47.77) meters

TURBENC1 has 1 tier(s) with a base elevation of 0.00 Meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER COORDINATES X	Y
TURBENC1	1	25	13.72	4		
					556694.05	3028588.17 meters
					(19.74	-0.07) meters
					556708.49	3028588.17 meters
					(34.19	-0.07) meters
					556708.49	3028580.95 meters
					(34.19	-7.29) meters
					556694.05	3028580.95 meters
					(19.74	-7.29) meters

AIRINT1 has 1 tier(s) with a base elevation of 0.00 Meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER COORDINATES X	Y
AIRINT1	1	29	16.46	4		
					556708.49	3028591.35 meters
					(34.19	3.11) meters
					556717.63	3028591.35 meters
					(43.33	3.11) meters
					556717.63	3028577.04 meters
					(43.33	-11.20) meters
					556708.49	3028577.04 meters
					(34.19	-11.20) meters

AIRINT3 has 1 tier(s) with a base elevation of 0.00 Meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER COORDINATES X	Y
AIRINT3	1	33	16.46	4		
					556708.09	3028518.47 meters
					(33.79	-69.76) meters
					556717.63	3028518.47 meters
					(43.33	-69.76) meters
					556717.63	3028503.96 meters
					(43.33	-84.27) meters
					556708.09	3028503.96 meters
					(33.79	-84.27) meters

```
WATERTNK has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS          X            Y

WATERTNK    1        37     14.63      8
                                               556808.00  3028493.70 meters
                                           (      133.69      -94.54) meters
                                               556804.95  3028486.48 meters
                                           (      130.65     -101.76) meters
                                               556797.73  3028483.43 meters
                                           (      123.42     -104.81) meters
                                               556790.51  3028486.48 meters
                                           (      116.20     -101.76) meters
                                               556787.46  3028493.70 meters
                                           (      113.15      -94.54) meters
                                               556790.51  3028500.92 meters
                                           (      116.20      -87.32) meters
                                               556797.73  3028503.96 meters
                                           (      123.42      -84.27) meters
                                               556804.95  3028500.92 meters
                                           (      130.65      -87.32) meters


FUELSTNK has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS          X            Y

FUELSTNK    1        41     14.63      8
                                               556819.59  3028435.46 meters
                                           (      145.29     -152.77) meters
                                               556814.89  3028424.27 meters
                                           (      140.58     -163.97) meters
                                               556803.69  3028419.56 meters
                                           (      129.39     -168.67) meters
                                               556792.49  3028424.27 meters
                                           (      118.19     -163.97) meters
                                               556787.79  3028435.46 meters
                                           (      113.49     -152.77) meters
                                               556792.49  3028446.66 meters
                                           (      118.19     -141.58) meters
                                               556803.69  3028451.36 meters
                                           (      129.39     -136.87) meters
                                               556814.89  3028446.66 meters
                                           (      140.58     -141.58) meters


FUELDTNK has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF       CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS          X            Y

FUELDTNK    1        45     12.19      8
                                               556771.82  3028436.59 meters
                                           (       97.52     -151.65) meters
                                               556769.31  3028430.56 meters
                                           (       95.00     -157.68) meters
                                               556763.28  3028428.04 meters
                                           (       88.97     -160.19) meters
```

```
                                       556757.25  3028430.56 meters
                                   (      82.94     -157.68) meters
                                       556754.73  3028436.59 meters
                                   (      80.43     -151.65) meters
                                       556757.25  3028442.62 meters
                                   (      82.94     -145.62) meters
                                       556763.28  3028445.13 meters
                                   (      88.97     -143.10) meters
                                       556769.31  3028442.62 meters
                                   (      95.00     -145.62) meters

CTRLBLNG has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS       X            Y

CTRLBLNG    1        49    13.72     4
                                       556684.04  3028456.27 meters
                                   (       9.74     -131.97) meters
                                       556722.86  3028456.27 meters
                                   (      48.56     -131.97) meters
                                       556722.86  3028440.90 meters
                                   (      48.56     -147.34) meters
                                       556684.04  3028440.90 meters
                                   (       9.74     -147.34) meters

BLDG14   has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS       X            Y

BLDG14      1        53    14.67     8
                                       556645.02  3028476.80 meters
                                   (     -29.28     -111.43) meters
                                       556636.01  3028455.27 meters
                                   (     -38.29     -132.96) meters
                                       556614.48  3028446.26 meters
                                   (     -59.82     -141.97) meters
                                       556592.95  3028455.27 meters
                                   (     -81.36     -132.96) meters
                                       556583.94  3028476.80 meters
                                   (     -90.36     -111.43) meters
                                       556592.95  3028498.33 meters
                                   (     -81.36      -89.90) meters
                                       556614.48  3028507.34 meters
                                   (     -59.82      -80.89) meters
                                       556636.01  3028498.33 meters
                                   (     -38.29      -89.90) meters

CHILLER1 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS       X            Y

CHILLER1    1        57     2.44     4
                                       556584.27  3028617.65 meters
                                   (     -90.03       29.42) meters
```

```
                                                       556600.70  3028617.65 meters
                                                  (       -73.60        29.42) meters
                                                       556600.70  3028521.19 meters
                                                  (       -73.60       -67.04) meters
                                                       556584.27  3028521.19 meters
                                                  (       -90.03       -67.04) meters

CHILLER2 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

CHILLER2    1       61      2.44     4
                                                       556608.78  3028617.32 meters
                                                  (       -65.52        29.08) meters
                                                       556626.21  3028617.32 meters
                                                  (       -48.10        29.08) meters
                                                       556626.21  3028587.51 meters
                                                  (       -48.10        -0.73) meters
                                                       556608.78  3028587.51 meters
                                                  (       -65.52        -0.73) meters

Number of stacks to be processed :    3

                      STACK            STACK    COORDINATES
 STACK NAME       BASE  HEIGHT           X            Y

 STCK1            0.00    24.38 Meters
                                     556670.26  3028584.26 meters
                                (       -4.04        -3.97) meters
 STCK2            0.00    24.38 Meters
                                     556670.06  3028547.82 meters
                                (       -4.24       -40.42) meters
 STCK3            0.00    24.38 Meters
                                     556670.06  3028511.32 meters
                                (       -4.24       -76.92) meters

   No stacks have been detected as being atop any structures.


                         Overall GEP Summary Table
                              (Units: meters)


StkNo:  1  Stk Name:STCK1    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   16.47              *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  314.50
  Bldg-Tier nos. contributing to GEP:  21


StkNo:  2  Stk Name:STCK2    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   16.46              *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  223.25
  Bldg-Tier nos. contributing to GEP:  29
```

```
StkNo:  3  Stk Name:STCK3    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   16.47              *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  225.50
  Bldg-Tier nos. contributing to GEP:  21
```

APPENDIX E

DETAILED ISCST3 MODELING RESULTS

ISCST3 Model Resultsfor the Proposed Combustion Turbines

Table E-1 Distillate Oil

DistillateOil - Class II Receptors								
	Normalized Concentration ($\mu g/m^3$ per g/sec)*						Location	
100% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.5219	0.62008	0.571	0.63242	0.4234	0.632	555670	3029848.0
3-Hr	0.2571	0.25993	0.24	0.24747	0.2636	0.264	562670	3012548.0
8-Hr	0.13872	0.15639	0.1494	0.14115	0.1245	0.156	538670	3024548.0
24-hr	0.05595	0.05553	0.0527	0.06462	0.0515	0.065	540670	3038548.0
Annual	0.00435	0.00441	0.0047	0.0047	0.0048	0.005	547670	3033548.0
75% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	1.22439	0.6363	0.5868	0.71752	1.5901	1.590	556770	3028648.0
3-Hr	0.40813	0.29918	0.2802	0.28341	0.53	0.530	556770	3028648.0
8-Hr	0.16111	0.1804	0.1742	0.15719	0.2897	0.290	556730.56	3028620.5
24-hr	0.07015	0.06893	0.0617	0.07387	0.0966	0.097	556730.56	3028620.5
Annual	0.0051	0.00519	0.0056	0.00543	0.0057	0.006	547670	3033548.0
50% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	1.42526	0.98102	0.8377	0.84463	1.8415	1.842	556770	3028648.0
3-Hr	0.47509	0.33903	0.3213	0.32084	0.6874	0.687	556470	3028548.0
8-Hr	0.23613	0.20455	0.1994	0.2076	0.3416	0.342	556730.56	3028620.5
24-hr	0.07871	0.07947	0.0712	0.08313	0.1385	0.138	556580.94	3028572.5
Annual	0.00575	0.00599	0.0063	0.0062	0.0065	0.006	547670	3033548.0
* Based on 1 g/sec for each turbine stack (3)								

ISCST3 Model Resultsfor the Proposed Combustion Turbines

Table E-2 Natural Gas

Natural Gas - Class II Receptors								
	Normalized Concentration (μg/m^3 per g/sec)*						Location	
100% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.524	0.622	0.573	0.634	0.432	0.634	555670	3029848.0
3-Hr	0.261	0.264	0.244	0.251	0.269	0.269	562670	3012548.0
8-Hr	0.142	0.159	0.152	0.142	0.126	0.159	538670	3024548.0
24-hr	0.057	0.060	0.054	0.066	0.052	0.066	540670	3038548.0
Annual	0.00442	0.0045	0.0049	0.00477	0.00491	0.005	547670	3033548.0
75% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	1.253	0.639	0.589	0.720	1.626	1.626	556770	3028648.0
3-Hr	0.418	0.305	0.286	0.289	0.542	0.542	556770	3028648.0
8-Hr	0.166	0.184	0.178	0.160	0.296	0.296	556730.56	3028620.5
24-hr	0.071	0.070	0.063	0.075	0.099	0.099	556730.56	3028620.5
Annual	0.00516	0.00528	0.0057	0.0055	0.00575	0.006	547670	3033548.0
50% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	1.459	1.006	0.840	0.847	1.883	1.883	556770	3028648.0
3-Hr	0.486	0.345	0.328	0.327	0.705	0.705	556470	3028548.0
8-Hr	0.242	0.208	0.203	0.213	0.350	0.350	556730.56	3028620.5
24-hr	0.081	0.081	0.073	0.085	0.142	0.142	556580.94	3028572.5
Annual	0.00589	0.00612	0.0064	0.00636	0.00665	0.007	547670	3033548.0
* Based on 1 g/sec for each turbine stack (3)								

APPENDIX F

KEY TO ISCST3 MODELING FILES ON CD-ROM

10/31/00

Key to files on CDROM - Midway Energy, L.L.C. Florida

- *Directory :\Midway\GEP-BPIP - contains BPIP input and output files*

File Naming Convention:

Midgep.bpi - BPIP input file
Midgep.sum - BPIP input summary
Midgep.bpo - BPIP output file

- *Directory :\Midway\ISCST3\Natural Gas - contains ISCST3 input and output files for Natural Gas* modeled with an emission rate of 1 g/sec.

File Naming Convention:

NG10087 - Natural Gas with turbines at 100% load with 1987 metdata, repeat for '88, '89, '90 and '91
NG07587 - Natural Gas with turbines at 75% load with 1987 metdata, repeat for '88, '89, '90 and '91
NG05087 - Natural Gas with turbines at 50% load with 1987 metdata, repeat for '88, '89, '90 and '91

- *Directory :\Midway\ISCST3\Distillate Oil - contains ISCST3 input and output files for Distillate Oil modeled with an emission rate of 1 g/sec.*

File Naming Convention:

OI10087 - Distillate Oil with turbines at 100% load with 1987 metdata, repeat for '88, '89, '90 and '91
OI07587 - Distillate Oil with turbines at 75% load with 1987 metdata, repeat for '88, '89, '90 and '91
OI05087 - Distillate Oil with turbines at 50% load with 1987 metdata, repeat for '88, '89, '90 and '91

- *Directory :\Midway\metdata - contains five years ISCST3 meteorological data, 1987-1991, West Palm Beach International Airport*

File Naming Convention:

12844-87 - 1987 meteorological data, repeat for '88,'89,'90 and '91

****

Best Available Copy

SCRIPPS HOWARD

THE TRIBUNE

ST. LUCIE COUNTY, FLORIDA

P.O. Box 69, Fort Pierce, FL 34954-0069

RECEIVED

DEC 29 2000

BUREAU OF AIR REGULATION

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF ST. LUCIE

Before the undersigned authority personally appeared, Lynn Ferraro, General Manager; Kathy LeClair, Business Manager or Dorothy Dicks, Advertising Manager of The Tribune, a daily newspaper published at Fort Pierce in St. Lucie County, Florida; that the attached copy of advertisement was published in The Tribune in the following issues below. Affiant further says that the said Tribune is a newspaper published at Fort Pierce in said St. Lucie County, Florida and that the said newspaper has heretofore been continuously published in said St. Lucie County, Florida daily and distributed in St. Lucie County, Florida, for a period of one year next preceding the first publication of attached copy of advertisement; and affiant further says that he/she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper. The Tribune has been entered as second class matter at the Post Office in Fort Pierce, St. Lucie County, Florida and has been for a period of one year next preceding the first publication of the attached copy of advertisement.

Ad #	Name	Date	Price Per Day	PO #
2047502	DEPT., OF ENVIRONME	12/21/2000	$419.44	
		Total	$419.44	

Subscribed and sworn to me before this date:

12/21/2000

Kathy K LeClair

Ellen McCarthy

Notary Public

SEAL

STATE OF FLORIDA NOTARY PUBLIC
ELLEN McCARTHY
My Comm Exp. 8/29/2002
No. CC 758033
[ ] Personally Known [ ] Other I.D.

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 1110099-002-AC (PSD-FL-305)
Midway Energy Center - Units 1-3
St. Lucie County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Midway Development Company, L.L.C (an affiliate of Enron North America). The permit is to construct three 170-megawatt (MW) dual-fuel combustion turbines with inlet chillers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Midway Energy Center to be located West of I-95 near Port St. Lucie and Fort Pierce in St. Lucie County. A Best Available Control Technology (BACT) determination was required for sulfur dioxide (SO2), particulate matter (PM/PM10), nitrogen oxides (NOx), sulfuric acid mist (SAM), and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Midway Development Company (affiliate of Enron North America), 1400 Smith Street, Houston, Texas 77002-7631.

The new units will be nominal 170 MW General Electric PG7241FA combustion turbine-electrical generators. The units will operate in simple cycle mode and intermittent duty. The units will operate primarily on natural gas and will be permitted to operate 3,500 hours per year of which no more than 1000 hours per year will be using maximum 0.05 percent sulfur distillate fuel oil.

NOX emissions will be controlled by Dry Low NOX (DLN-2.6) combustors. The units must meet a continuous emission limit of 9 parts per million by volume, dry at 15 percent oxygen (ppm). NOX will be controlled to 42 ppm by wet injection when firing fuel oil. Sulfuric acid mist, SO2, and PM/PM10 will be limited by use of clean fuels. Emissions of VOC and CO will be controlled by good combustion practices.

The maximum emissions from the combustion turbines in tons per year based on the original application are summarized below. There will be minor emissions of VOC from the fuel oil storage tank. However total VOC emissions will still be less than significant for PSD purposes.

Pollutant	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM10	119	25/15
CO	213	100
NOX	708	40
VOC	20	40
SO2	190	40
Sulfuric Acid Mist	29	7

Air quality impact analyses were conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels. There will be insignificant impacts on visibility in the Class I Everglades National Park. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increment.

The Department will issue the [illegible]

SEAL

ELLEN MCCARTHY
My Comm Exp. 8/29/2002
No. CC 758033
[ ] Personally Known [ ] Other I.D.

STATE OF FLORIDA NOTARY PUBLIC

the fuel oil storage tank. However total VOC emissions will still be less than significant for PSD purposes.

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NOX	708	40
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The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

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

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

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

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

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

Dept. of Environmental Protection	Dept. of Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southeast District Office	Southeast District Branch Office
111 S. Magnolia Drive, Suite 4	400 North Congress Ave.	1801 SE Hillmoor Drive, Suite 204
Tallahassee, Florida 32301	West Palm Beach, FL 33416-5425	Port St. Lucie, Florida 34952
Telephone: 850/488-0114	Telephone: 561/681-6600	Telephone: 561/398-2806
Fax: 850/922-6979	Fax: 561/681-6755	Fax: 561/398-2815

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air by clicking on permitting and then construction permits.

cc: C. Carlson
I. Goldman, SED
EPA
NPS

FLORIDA

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

December 15, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

Re: DEP File No. 1110099-002-AC (PSD-FL-304)
Midway Energy Center
Three Simple Cycle Combustion Turbines

Dear Mr. Jacoby:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Midway Energy Center to be located near Port St. Lucie and Fort Pierce in St. Lucie County. The Department's Intent to Issue Air construction Permit and the "Public Notice of Intent to Issue Air Construction Permit" are also included.

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

Please submit any other written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address or contact him at 850/921-9523.

Sincerely,

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

CHF/al

Enclosures

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

COMPLETE THIS SECTION ON DELIVERY

A. Received by (*Please Print Clearly*) H. WYATT

B. Date of Delivery 12-22-00

C. Signature
X H. Wyatt

☐ Agent
☐ Addressee

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

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

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

2. Article Number (*Copy from service label*)
7099 3400 0000 1453 3280

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

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

7099 3400 0000 1453 3280

Article Sent To:
Mr. Ben Jacoby, Director

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

Postmark Here

Name (*Please Print Clearly*) (*to be completed by mailer*)
Mr. Ben Jacoby, Director
Street, Apt. No.; or PO Box No.
1400 Smith Street
City, State, ZIP+4
Houston, Texas 77002-7631

PS Form 3800, July 1999 See Reverse for Instructions

In the Matter of an
Application for Permit by:

Mr. Ben Jacoby, Director
Midway Development Company, L.L.C.
1400 Smith Street
Houston, Texas 77002-7631

DEP File No. 1110099-002-AC (PSD-305)
Midway Energy Center, Units 1 – 3
St. Lucie County

______________________________/

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

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

The applicant, Midway Development Company, L.L.C., applied on November 9, 2000 to the Department for an air construction permit to construct three 170-megawatt dual-fuel combustion turbines with inlet chillers, three 80-foot stacks, a natural gas heater, a 2.5 million gallon fuel oil storage tank, and a 0.6 million gallon fuel oil day storage tank for the Midway Energy Center to be located near Port St. Lucie in St. Lucie County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

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

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

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

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

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

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

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

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

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

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

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

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

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/18/00 to the person(s) listed:

Ben Jacoby, MDC*
Gregg Worley, EPA
John Bunyak, NPS
Isidore Goldman, DEP SED
Chair, St. Lucie County BCC
Blair Burgess, P.E., ENSR

Clerk Stamp

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

Charlotte J. Hayes 12/18/00
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1110099-002-AC (PSD-FL-305)

Midway Energy Center – Units 1-3
St. Lucie County

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Sulfuric Acid Mist	29	7

Air quality impact analyses were conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels. There will be insignificant impacts on visibility in the Class I Everglades National Park. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any AAQS or PSD increment.

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

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

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

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

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

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

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

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

Dept. of Environmental Protection	Dept. of environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Southeast District Office	Southeast District Branch Office
111 S. Magnolia Drive, Suite 4	400 North Congress Avenue	1801 SE Hillmoor Drive, Suite 204
Tallahassee, Florida 32301	West Palm Beach, Florida 33416-5425	Port St. Lucie, Florida 34952
Telephone: 850/488-0114	Telephone: 561/681-6600	Telephone: 561/398-2806
Fax: 850/922-6979	Fax: 561/681-6755	Fax: 561/398-2815

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air by clicking on permitting and then construction permits.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Midway Energy Center Units 1 - 3

Three 170-Megawatt Combustion Turbines
One 2.5-Million Gallon Fuel Oil Storage Tank
One 0.6 Million Gallon Fuel Oil Storage Tank
Gas-fired Heater

St. Lucie County

DEP File No. 1110099-002-AC (PSD-FL-305)

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

December 15, 2000

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Midway Development Company, L.L.C. (Midway)
1400 Smith Street
Houston, Texas 77002-7631

Authorized Representative: *Mr. Ben Jacoby*

1.2 Reviewing and Process Schedule

11-09-00: Date of Receipt of Application
12-15-00: Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The Midway Energy Center will be located in unincorporated St. Lucie County near the east coast of Florida. The site is located to the northwest of the intersection of I-95 and County Road 712 (W. Midway Road) near Port St. Lucie and Fort Pierce. There is already a substation in the vicinity. The location is approximately 180 kilometers North-Northeast of the Everglades National Park. The UTM coordinates for this facility are Zone 17; 556.67 km E; 3028.55 km N.

Figure 1 – Regional Location

Figure 2 – I-95 and 712 St. Lucie County

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

This proposed facility will generate 510 megawatts (nominal MW) of electrical power. The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), and a Best Available control Technology determination is required. Given that emissions of at least one single criteria pollutant will exceed 250 TPY, PSD Review and a BACT determination are required for each pollutant emitted in excess of the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. These values are: 40 TPY for NO_X, SO_2, and VOC; 25/15 TPY of PM/PM_{10}; 7 TPY of Sulfuric Acid Mist (SAM); and 100 TPY of CO.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT	SYSTEM	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
004	Fuel Storage	One 2.5-Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	One 0.6 Million Gallon Fuel Oil Storage Tank
006	Fuel Heating	One 13 million Btu per hour Natural Gas heater

Midway proposes to construct three nominal 170 MW General Electric PG7241FA simple cycle, intermittent duty combustion turbine-electrical-generators with inlet air chillers, 80-foot stacks, two fuel oil storage tanks, a natural gas heater, and ancillary equipment at the planned Midway Energy Center.

According to the revised application, the facility will emit approximately 708 tons per year (TPY) of nitrogen oxides (NO_X), 213 TPY of carbon monoxide (CO), 119 TPY of particulate matter (PM/PM_{10}), 190 TPY of sulfur dioxide (SO_2), 20 TPY of volatile organic compounds (VOC), and 29 TPY of sulfuric acid mist (SAM).

Significant emission rate increases per Table 212.400-2, F.A.C. will occur for CO, SO_2, SAM, PM/PM_{10} and NO_X. A BACT determination is required for each of these pollutants. An air quality impact review is also required for CO, PM/PM_{10}, NO_X, and SO_2.

Each turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors for the control of NO_X emissions to 9 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. Each turbine will have a maximum heat input rating of approximately 1,700 (gas) and 1,900 (oil) mmBtu/hr lower heating value (LHV) at 30°F while operating at 100% load. The main fuel will be natural gas and the units are proposed by Midway to operate up to 3,500 hours per year per unit of which 1000 hours per year per unit may be on maximum 0.05 percent sulfur distillate fuel oil.

The key components of the GE MS 7001FA (a predecessor of the PG 7241FA) are identified in Figure 3. An exterior view is also shown. Each unit will be delivered with 14 can-annular design, DLN-2.6 combustors instead of the earlier-generation combustors supplied with the MS7001FA.

4. PROCESS DESCRIPTION

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

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

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

Figure 4 is a simplified process flow diagram of the proposed Midway Project. In the Midway Project, the units will operate as peaking units in the simple cycle mode. Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is approximately 35 percent for F-Class combustion turbines in the simple cycle mode. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet air density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), an inlet air cooler (fogger or chiller) can be installed ahead of the combustion turbine inlet. At an ambient temperature of 95 °F, roughly 15 MW of power can be regained per unit by using a chiller to cool the inlet air to 50 °F.

In combined cycle projects, the gas turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator. The steam, in-turn, drives another electrical generator producing an additional 80-90 MW. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

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

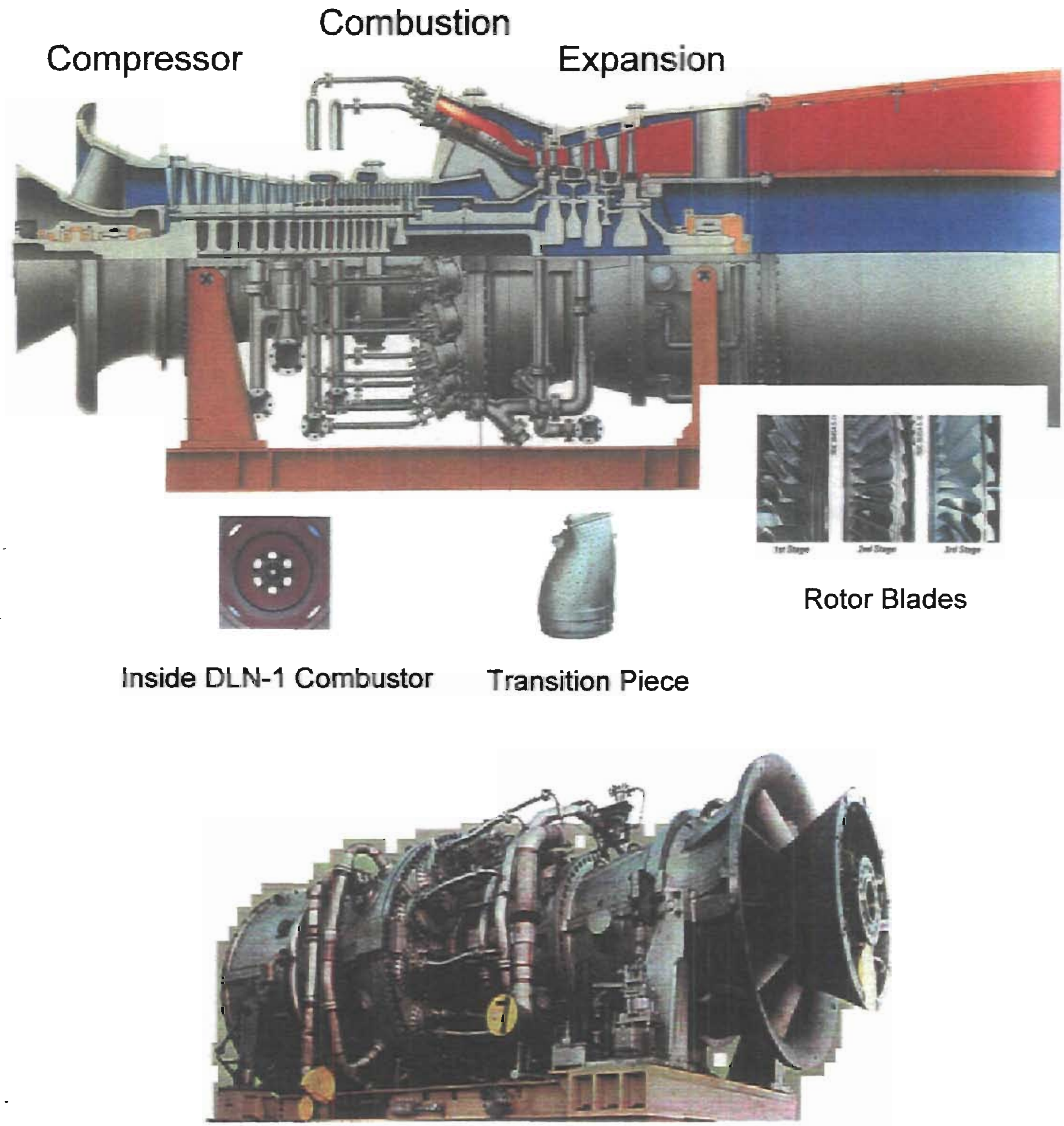

Figure 3 - Internal and External Views of Early GE 7FA

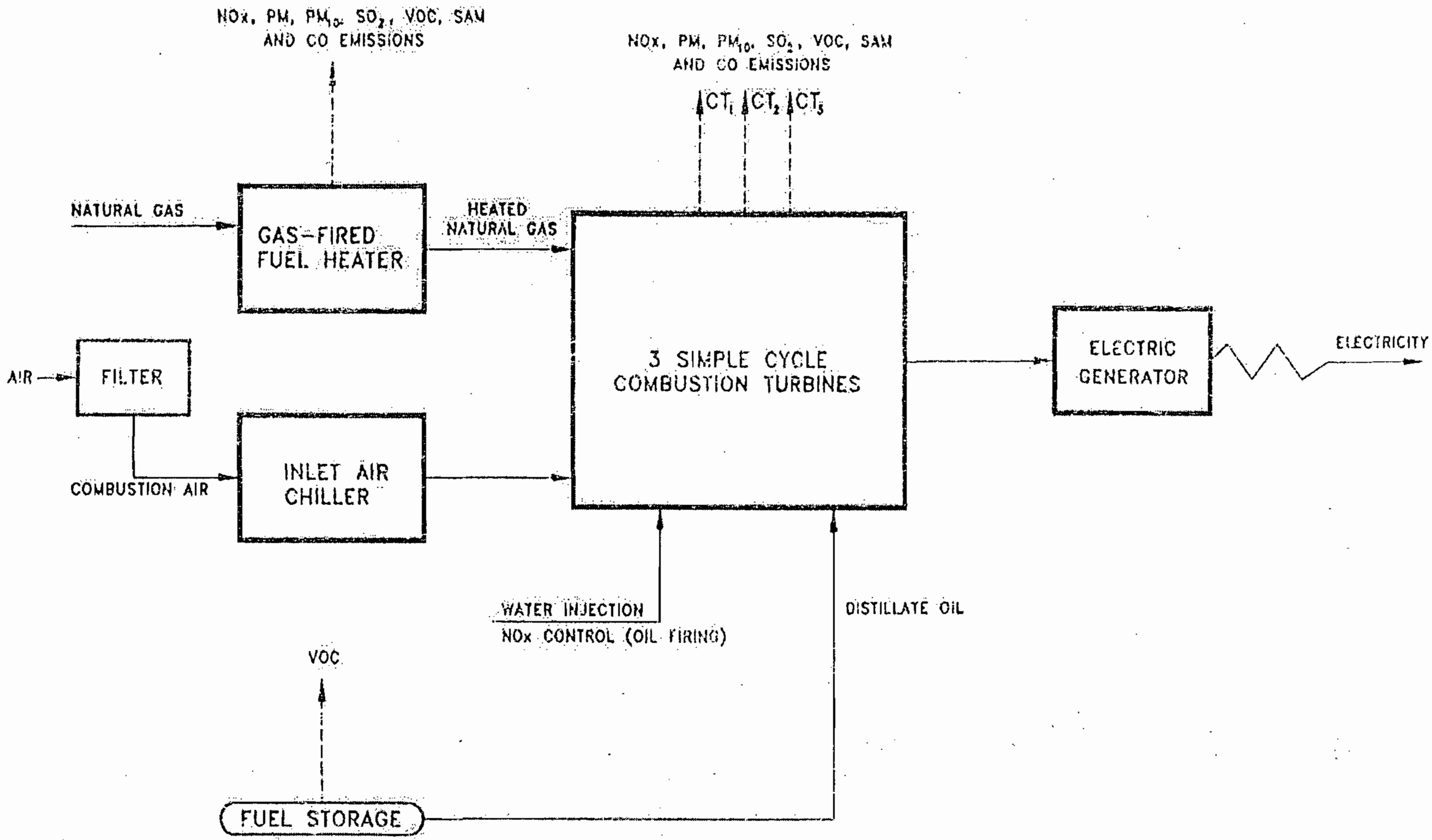

Figure 4 - Simple Cycle Process Flow Diagram

5. RULE APPLICABILITY

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

This facility will be located in St. Lucie County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) for the reasons given in Section 2.3, Facility Category, above.

This PSD review consists of an evaluation of resulting ambient air pollutant concentrations, and increases with respect to the National Ambient Air Quality Standards and Increments as well as a determination of Best Available Control Technology (BACT) for PM/PM_{10}, CO, SO_2, SAM and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth

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

5.1 State Regulations

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

5.2 Federal Rules

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

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Units 1-6 will emit the following PSD pollutants (Table 212.400-2, F.A.C.): PM/PM_{10}, SO_2, NO_X, CO, SAM, and negligible quantities of fluorides (F), mercury (Hg) and lead (Pb). The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for Units 1-3 are summarized in the Draft BACT document and Specific Condition Nos. 18-23 of Draft Permit PSD-FL-305.

6.2 Emission Summary

The annual emissions increases for all PSD pollutants as a result of the project are presented below:

PROJECT EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutant	Gas Firing[1]	Oil Firing[2]	Total[2]	PSD Significance	PSD REVIEW?
PM/PM_{10}	95	51	119	25	Yes
SO_2	56	150	190	40	Yes
NO_X	315	482	708	40	Yes
CO	157	100	213	100	Yes
Ozone (VOC)	16	7	20	40	No
Sulfuric Acid Mist	8	23	29	7	Yes
Total Fluorides	~0	~0	0.09	3	No
Mercury	~0	0.003	0.003	0.1	No
Lead	~0	0.03	0.03	0.6	No
HAPs	5	3	6	NA	NA

1. Based on 3,500 hours of gas firing per year per unit. Includes gas heater. Reference inlet air chiller temperature is 50 °F.
2. Based on 2,500 hours of gas firing and 1000 hours of fuel oil firing per year per unit. Includes storage tanks.

6.3 Control Technology

The PSD regulations require new major stationary sources to undergo a control technology review for each pollutant that may be potentially emitted above significant amounts. The control technology review requirements of the PSD regulations are applicable to emissions of NO_X, SO_2, CO, SAM, and PM/PM_{10}. Emissions control will be accomplished primarily by good combustion of clean natural gas and the limited use of low sulfur (0.05 percent) distillate fuel oil. The combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

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

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

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_x in the Surrounding Class II Area.
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

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

6.4.2 Models and Meteorological Data Used in the Air Quality Analysis

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

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

6.4.3 Significant Impact Analysis

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

The only significant impact analysis submitted for this project was for the surrounding Class II Area. The closest Class I Area to this project is the Everglades National Park (ENP). Since the ENP is over 180 km from the project site, plus the type and amount of emissions from the source, a Class I Area significant impact analysis was not required for this project. The following paragraphs explain the methodologies and results of the Class II analysis:

Receptors were placed around the proposed facility, which is located in a PSD Class II Area. A combination of fence line, near-field, mid-field, and far-field receptors were utilized for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at less than 100 meter intervals around the facility fence line. The remaining receptors consisted of a grouping of Cartesian receptor grids logarithmically spaced out to a distance 20 km from the facility. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility. The table below shows the results of the significant impact modeling for the Class II Area:

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

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.01	1	NO
	24-Hour	1.1	5	NO
	3-Hour	5.6	25	NO
PM_{10}	Annual	0.008	1	NO
	24-Hour	0.6	5	NO
CO	8-Hour	3.4	500	NO
	1-Hour	18.2	2000	NO
NO_2	Annual	0.05	1	NO

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

6.4.4 Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from these natural gas and oil-fired combustion turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, SO_2 and SAM as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels, which in-turn are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species. Due to the distance of the source from the ENP PSD Class I Area, plus the type and amount of emissions from the source, there is a low potential for visibility impacts. Therefore, the National Park Service required no regional haze analysis for this project.

Growth-Related Air Quality Impacts

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

The facility will require 6000 truckloads (an average of 17 per day) of fuel oil for 1000 hours of operation. If fuel oil usage is concentrated over a period of a few months, then the truck traffic will be more noticeable. In the near future, more natural gas will be available and less fuel oil will be used, resulting in less impacts.

Over the past few years the Public Service Commission has determined that a number of power projects are needed to help meet the low electrical reserve capacity throughout the State of Florida. No need determination was made for this specific project. A number of projects will be located in this area due to availability of natural gas, substations, and transmission capacity. The project is a response to statewide and regional growth and also accommodates more growth.

There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," low water requirements, and among the lowest air emissions per unit of electric power generating capacity for intermittent duty.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Section 112 of the Clean Air Act.

7. CONCLUSION

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

A. A. Linero, P.E., Administrator
Chris Carlson, Meteorologist

PERMITTEE:

Midway Development Company
1400 Smith Street
Houston, Texas 77002-7631

Permit No.	PSD-FL-305
File No.	1110099-002-AC
SIC No.	4911
Expires:	June 30, 2003

Authorized Representative:

Ben Jacoby

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality Permit for: three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers; one 2.5-million gallon fuel oil storage tank; one 0.6 million gallon fuel oil storage tank; a natural gas heater; and three 80-foot stacks. The units will operate in simple cycle mode and intermittent duty. The units will be equipped with Dry Low NO_X (DLN-2.6) combustors and wet injection capability.

The project will be located Northwest of the intersection of I-95 and W. Midway Road near Port St. Lucie and Ft. Pierce in unincorporated St. Lucie County. UTM coordinates are Zone 17; 556.7 km E; 3028.5 km N.

STATEMENT OF BASIS:

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

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

This facility is a new site. This permitting action is to install three dual-fuel nominal 170 megawatt (MW) General Electric PG7241FA combustion turbine-electrical generators with inlet air chillers, three 80-foot stacks, one 2.5-million gallon fuel oil storage tank, one 0.6-million gallon storage tank, a gas heater and ancillary equipment. Emissions from the new units will be controlled by Dry Low NO_X (DLN-2.6) combustors when operating on natural gas and wet injection when firing fuel oil. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

ARMS Emission Unit	System	Emission Unit Description
001	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
002	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
003	Power Generation	One nominal 170 Megawatt Gas Combustion Turbine-Electrical Generator with inlet air chiller
004	Fuel Storage	One 2.5-Million Gallon Fuel Oil Storage Tank
005	Fuel Storage	One 0.6 Million Gallon Fuel Oil Storage Tank
006	Fuel Heating	One 13 million Btu per hour Natural Gas heater

REGULATORY CLASSIFICATION

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

This facility is not within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because emissions are greater than 250 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, modifications at this facility resulting in emissions increases greater than any of the following values require review per the PSD rules as well as a determination of Best Available Control Technology (BACT): 40 TPY of NO_X, SO_2, or VOC; 25/15 TPY of PM/PM_{10}; 100 TPY of CO; or 7 TPY of sulfuric acid mist (SAM). This facility and the project are also subject to applicable provisions of Title IV, Acid Rain, of the Clean Air Act.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 12/xx/00 Notice of Intent published in ____________________
- 12/15/00 Distributed Intent to Issue Permit
- 11/09/00 Received Application

RELEVANT DOCUMENTS:

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

- Application received on November 9, 2000
- Letter from Enron North America dated December 5, 2000.
- Letter from U.S. EPA Region IV dated ______________
- Letter from National Park Service dated ______________
- Department's Intent to Issue and Public Notice Package dated December 15, 2000
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the *Permitting Authority*: Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the *Compliance Authority*: DEP Southeast District office, 400 North Congress Avenue W, West Palm, Florida, 33401 and phone number 561/681-6755, fax 561-681-6755. Copies shall be sent to the DEP Port St. Lucie Branch office, 1801 SE Hillsmoore Dr, C 204, Port St. Lucie, Florida 34952 and phone number 561/398-2806, fax 561/398-2815.

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

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

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

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

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

7. BACT Determination Revision: In accordance with Rule 62-212.400(6)(b), F.A.C. (and 40 CFR 51.166(j)(4)), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous

determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing (e.g. conversion to combined-cycle operation) short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 51.166(j)(4) and Rule 62-212.400(6)(b), F.A.C.]

8. Completion of Construction: The permit expiration date is June 30, 2003. Physical construction shall be complete by December 31, 2003. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

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

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

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

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southeast District and a copy to the DEP's Port St. Lucie Branch offices by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

13. Quarterly Reports: Semiannual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (2000 version), shall be submitted to the DEP's Southeast District and a copy to the DEP's Port St. Lucie Branch offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations.
[Rule 62-210.300, F.A.C.]

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

3. ARMS Emission Units 001-003, Power Generation, consisting of three 170 megawatt combustion turbines shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). [Rule 62-204.800(7)(b), F.A.C.]

4. ARMS Emission Unit 004, Fuel Storage, consisting of one 2.5 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

5. ARMS Emission Unit 005, Fuel Storage, consisting of one 0.6 million gallon distillate fuel oil storage tanks shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [Rule 62-204.800(7)(b), F.A.C.]

6. ARMS Emission Unit 006, Fuel Heating, consisting of one 13 million Btu per hour natural gas heater to heat natural gas used by the combustion turbines.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in these units.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
{Note: The limitation of this specific condition is more stringent than the NSPS sulfur dioxide limitation and thus assures compliance with 40 CFR 60.333 and 60.334}

8. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-3) at ambient conditions of 30 °F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,700 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,900 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing.
[Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

10. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Southeast District as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations.
[Rule 62-4.130, F.A.C.]

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

12. Circumvention: The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rules 62-210.650, F.A.C.]

13. Maximum allowable hours: The three stationary gas turbines shall operate no more than an average of 3,500 hours per installed unit during any calendar year. The three stationary gas turbines shall operate no more than an average of 1000 hours per installed unit on fuel oil during any calendar year. No single combustion turbine shall operate more than 5,000 hours in a single year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions), Rule 62-212.400, F.A.C. (BACT)]

14. Fuel oil usage: The amount of back-up fuel (fuel oil) burned at the site (in BTU's) shall not exceed the amount of natural gas (primary fuel) burned at the site (in BTU's) during any consecutive 12-month period. The Department may waive this requirement during the first 24 months of operation based on natural gas availability.
[Rule 62-212.400, F.A.C. (BACT)]

Control Technology

15. Dry Low NO_X (DLN-2.6) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas.
[Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

16. A water injection (WI) system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions.
[Design, Rules 62-4.070 and 62-212.400, F.A.C. (BACT)]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions consistent with normal operation and maintenance practices and shall be maintained to minimize NO_X emissions and CO emissions, consistent with normal operation and maintenance practices. Operation of the DLN systems in the diffusion-firing mode shall be minimized when firing natural gas. [Rule 62-4.070 and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following is a summary of the emission limits and required technology.

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	18/34 lb/hr (Gas/Fuel Oil) 10 Percent Opacity (Gas or Fuel Oil)
VOC (not PSD)	As Above	2.8 ppmvd (Gas or Fuel Oil)
CO	As Above	12 ppmvd (Gas) 20 ppmvd (Fuel Oil)
SO_2 and Sulfuric Acid Mist	Pipeline Natural Gas Low Sulfur Fuel Oil	2 gr S/100 ft^3 (in Gas) 0.05% S (in Fuel Oil)
NO_X	Dry Low NO_X for Natural Gas Wet Injection and limited Fuel Oil usage	9 ppmvd @15% O_2 (Gas) 42 ppmvd @15% O_2 (Fuel Oil)

19. Nitrogen Oxides (NO_X) Emissions:

- *While firing Natural Gas*: The emission rate of NO_X in the exhaust gas shall not exceed 9 ppmvd @15% O_2 on a 24-hr rolling average as measured by the continuous emission monitoring system (CEMS) in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 62 pounds per hour nor 9 ppmvd @15% O_2 to be demonstrated by the initial stack test using EPA Method 20. [Rule 62-212.400, F.A.C.]
- *While firing Fuel Oil*: The concentration of NO_X in the exhaust gas shall not exceed 42 ppmvd at 15% O_2 on the basis of a 3-hr rolling average as measured by the CEMS in the manner described below. In addition, NO_X emissions calculated as NO_2 shall exceed neither 332 lb/hr nor 42 ppmvd @15% O_2 to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- *NO_X Reduction Plan*: The permittee shall develop a NO_X reduction plan when the hours of oil firing reach 500 hours per year per unit. This plan shall include a testing protocol designed to establish the maximum water injection rate and the lowest NO_X emissions possible without adversely affecting the actual performance of the gas turbine. The testing protocol shall set a range of water injection rates and attempt to quantify the corresponding NO_X emissions for each rate and noting any problems with performance. Based on the test results, the plan shall recommend a new NO_X emissions limiting standard and shall be submitted to the Department's Bureau of Air Regulation and Compliance Authority for review. If the Department determines that a lower NO_X emissions standard is warranted for oil firing, this permit shall be revised. [Rule 62-212.400, F.A.C., BACT Determination].

20. Carbon Monoxide (CO) Emissions: The concentration of CO in the stack exhaust gas shall exceed neither 12 ppmvd nor 31 lb/hr (gas) and neither 20 ppmvd nor 46 lb/hr (fuel oil) to be demonstrated by stack tests. [Rule 62-212.400, F.A.C.]

21. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the stack exhaust gas shall exceed neither 2.8 ppmvd nor 6 lb/hr (gas or fuel oil) to be demonstrated by initial stack tests. [To demonstrate non-applicability of Rule 62-212.400, F.A.C.]

22. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) Emissions: SO2 and SAM emissions shall be limited by firing pipeline natural gas (sulfur content less than 2 grains per 100 standard cubic foot) or No. 2 distillate fuel oil with a maximum 0.05 percent sulfur for 1000 hours per year per unit. Emissions of SO_2 shall exceed neither 11 lb/hr (natural gas) nor 104 lb/hr (fuel oil). Emissions of sulfuric acid mist shall exceed neither 2 lb/hr (natural gas) nor 16 lb/hr (fuel oil). These emissions shall be measured by applicable compliance methods described below.
[40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C]

23. Particulate Matter (PM/PM_{10}): PM/PM_{10} emissions shall exceed neither 18 lb/hr (gas) nor 34 lb/hr (fuel oil) to be demonstrated by initial stack tests. [Rule 62-212.400, F.A.C.]

24. Visible Emissions: Visible Emissions shall not exceed 10 percent opacity to be demonstrated by visual observation tests.
[Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. Excess Emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

26. Excess Emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

27. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southeast District within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Following the NSPS format, 40 CFR 60.7 Subpart A, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 18 and 19.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (2000 version)].

COMPLIANCE DETERMINATION

28. Compliance Test Schedules: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit and as required by the *Compliance Authority*. [Rules 62-204.800 and 62-4.070(3) F.A.C.]

    - *Initial*: Initial (I) performance tests (for both fuels) shall be performed on each unit while firing natural gas as well as while firing oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change or tuning of combustors.
    - *Annual*: Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each unit as indicated.

- *Prior Permit Renewal*: All tests shall be conducted within 12 months prior permit renewal.

29. Reference Methods: The following reference methods as described in 40 CFR 60, Appendix A (2000 version), and adopted by reference in Chapter 62-204.800, F.A.C. shall be used to demonstrate compliance with the allowable emissions limits. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
    - EPA Reference Method 5, "Determination of Particulate Matter Emissions from Stationary Sources" (I). (Note: Use Method 202 for condensable fraction)
    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for NO_X compliance with 40CFR60 Subpart GG.
    - EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirements.
    - EPA Reference Method 25A, "Determination of Total Hydrocarbon Concentrations." Correction for methane by EPA Method 18 is allowed. Initial test only.

30. Compliance with CO emission limits: An initial test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75

31. Compliance with the VOC emission limits: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required.

32. Compliance with the NOx emission limits: Compliance with the NO_X emissions limits shall be determined by stack tests and a CEMS as specified in specific conditions 30, 45 and 46.

33. Compliance with the PM/PM_{10} and VE emission limits: Initial and annual tests are required for visible emissions (VE). Initial stack test is required for PM/PM_{10}. Tests for PM and VE shall be conducted concurrently.

34. Continuous compliance with the PM/PM_{10}, SO_2 and sulfuric acid mist emission limits: Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and the restricted use of No. 2 distillate fuel oil (or superior grade) are the methods for determining continuous compliance for PM/PM_{10}, SO_2 and sulfuric acid mist.

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

36. Testing procedures: Initial testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

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

38. Test Notification: The DEP's Southeast District and the DEP's Port St. Lucie District offices shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

39. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

40. Test Results: Compliance test results indicating the results of the required compliance tests shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie District offices no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the

Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

42. Notifications: All notifications and reports required by 40 CFR60, Subpart A shall be submitted to the DEP's Southeast District and the DEP's Port St. Lucie District offices.

MONITORING REQUIREMENTS

43. Continuous Monitoring System Procedures: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the NO_X emissions from each CT. Each device shall properly function prior to the initial performance tests and comply with the applicable monitoring system requirements of 40 CFR 75.62. Upon request from DEP, the CEMS emission rates for NO_X on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 62-4.130, F.A.C and 40CFR75]

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

45. Continuous Monitoring System Operation: The continuous monitoring systems (CEMS) for NO_X shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Valid hourly emission rates shall not include periods of startup, shutdown, fuel switching, or

malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as require in Specific Conditions 24 and 46. [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 60.13, 40 CFR 75].

46. Continuous Compliance with the NO_X Emission Limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on a 24-hour rolling average (gas) and 3-hr rolling (oil). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of 24 valid hourly measurements from the previous operating hours. A valid hourly emission rate shall be calculated for each hour (during which fuel is fired) in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction unless prohibited by Rule 62-210.700, F.A.C. [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 75]

47. CEMS for Reporting Excess Emissions: The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (2000 version). Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40 CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15 % oxygen) are above the permit limits listed in Specific Conditions 20 and 21 shall be reported to the DEP South District office as required in Specific Condition 29.

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

49. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative (DR), that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

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

51. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Midway Energy Center
PSD-FL-305 and 1110099-002-AC
St. Lucie County, Florida

BACKGROUND

The applicant, Midway development Company, L.L.C. (Midway, an affiliate of Enron North America) proposes to install three nominal 170-megawatt (MW) General Electric PG 7241 FA combustion turbine-electrical generators at the planned Midway Energy Center, East of Arcadia in unincorporated St. Lucie County. The proposed project will constitute a New Major Facility per Rule 62-212.400(d)2.a., Florida Administrative Code (F.A.C.) because it will have the potential to emit at least 250 tons per year of a regulated pollutant. It is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. Emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) will exceed the "Significant Emission Rates" with respect to Table 212.400-2, (F.A.C.). PSD and BACT reviews are required for each of these pollutants.

The new units will operate in simple cycle mode and intermittent duty and exhaust through separate 80-foot stacks. Midway proposes to operate these units up to 3,500 hours per year per unit of which 1000 hr/yr/unit may be on maximum 0.05 percent sulfur distillate fuel oil. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated December 15, 2000, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on November 9, 2000 (revised December 5) and included a proposed BACT proposal prepared by the applicant's consultant, ENSR.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Dry Low NO_X Combustors Water Injection (Oil)	9 ppmvd @ 15% O_2 (gas)[1] 42 ppmvd @ 15% O_2 (oil)
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil (1000 hr/yr) Combustion Controls	18 pounds per hour (gas) 34 pounds per hour (oil)
Carbon Monoxide	As Above	9 ppmvd (gas, baseload) 30 ppmvd (oil baseload)
Sulfur Dioxide/Sulfuric Acid Mist	As Above	2 grain S/100 std cubic feet (gas) 0.05 percent sulfur (oil)

BACT DETERMINATION PROCEDURE:

In accordance with Rule 62-212.400, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

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

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by Midway is well within the NSPS limit, which allows NO_X emissions in the range of 100 - 110 ppmvd for the high efficiency units to be purchased for the Midway Energy Center.

A National Emission Standard for Hazardous Air Pollutants (NESHAP) under development exists for stationary gas turbines. However this facility will not be subject to the NESHAP or to a requirement for a case-by-case determination of maximum achievable control technology because HAP emissions will be less than 10 TPY.

DETERMINATIONS BY EPA AND STATES:

The following tables include some recently permitted simple cycle turbines. Two (Carson and McClellan) were permitted in ozone non-attainment areas and two (Lakeland and PREPA) were permitted as continuous duty projects. The proposed Midway Energy Center is included to facilitate comparison.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Project Location	Power Output (MW)	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Midway St. Lucie, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 11/00. 1000 hrs on oil
Pompano Beach, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 10/00. 1000 hrs on oil
DeSoto County, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Issued 7/00. 1000 hrs on oil
Shady Hills Pasco, FL	510	9 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE PG7241FA CTs Application 2/00. 1000 hrs on oil
Vandolah Hardee, FL	680	9 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
Oleander Brevard, FL	850	9 - NG 42 - No. 2 FO	DLN WI	5x170 MW GE PG7241FA CTs Issued 11/99. 1000 hrs on oil
JEA Baldwin, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Reliant Osceola, FL	510	10.5 - NG 42 - No. 2 FO	DLN WI	3x170 MW GE MS7241FA CTs Draft 11/99. 750 hrs on oil
TEC Polk Power, FL	330	10.5 – NG 42 – No. 2 F.O.	DLN WI	2x165 MW GE MS7241FA CTs Issued 10/99. 750 hrs on oil
Dynegy, FL	510	15 – NG	DLN	3x170 MW WH 501F CTs Application 10/99. Gas only
Dynegy Heard, GA	510	15 – NG	DLN	3x170 MW WH 501F CTs Application. Gas only
Tenaska Heard, GA	960	15 - NG 42 - No. 2 FO	DLN WI	6x170 MW GE PG7241FA CTs Issued 12/98. 720 hrs on oil
Thomaston, GA	680	15 - NG 42 - No. 2 FO	DLN WI	4x170 MW GE PG7241FA CTs Application. 1687 hrs on oil
Dynegy Reidsville, NC	900	15 – NG (by 2002) 42 – No. 2 FO	DLN WI	5x180 MW WH 501F CTs Initially 25 ppm NO_X limit on gas Draft 5/98. 1000 hrs on oil.
Lyondell Harris, TX	160	25 – NG	DLN	1x160 MW WH 501F CTs Issued 11/99. Gas only
Southern Energy, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
RockGen Cristiana, WI	525	15/12 – NG 42 - No. 2 FO	DLN WI	3x175 MW GE PG7241FA CTs 15/12 ppm are on 1/24 hr basis Issued 1/99. 800 hrs on oil
Carson Energy, CA	42	5 – NG (LAER)	Hot SCR	42 MW LM6000PA. Startup 1995. Ammonia limit is 20 ppmvd
McClelland AFB, CA	85	5 – NG (LAER)	Hot SCR	85 MW GE 7EA. Applied 1999 Ammonia proposal 10 ppmvd
Lakeland, FL	250 CON	9/9 – NG (by 2002) 42/15 - No. 2 FO	DLN/HSCR WI/HSCR	250 MW WH 501G CT Initially 25 ppm NO_X limit on gas Issued 7/98. 250 hrs on oil.
PREPA, PR	248 CON	10 - No. 2 FO	WI & HSCR	3x83 MW ABB GT11N CTs Issued 12/95.

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

Project Location	CO - ppm (or as indicated)	VOC - ppm (or as indicated)	PM - lb/hr (or as indicated)	Technology and Comments
Midway St. Lucie, FL	9 - NG 30 - FO	1.4 – NG 1.4– FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
Pompano Beach, FL	9 - NG 30 - FO	1.4 – NG 1.4-- FO	18 lb/hr - NG 34 lb/hr - FO	Clean Fuels Good Combustion
DeSoto County, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Shady Hills Pasco, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Vandolah Hardee, FL	12 - NG 20 - FO	1.4 – NG 7 – FO	10 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Oleander Brevard, FL	12 - NG 20 - FO	3 – NG 6 – FO	10% Opacity	Clean Fuels Good Combustion
JEA Baldwin, FL	12 - NG 20 - FO	1.4 – NG/FO Not PSD	9/17 lb/hr – NG/FO 10% Opacity	Clean Fuels Good Combustion
Reliant Osceola, FL	10.5 - NG 20 - FO	2.8 lb/hr – NG 7.5 lb/hr – FO	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
TEC Polk Power, FL	15 - NG 33 - FO	7 – NG 7 – FO	10% Opacity	Clean Fuels Good Combustion
Dynegy, FL	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Dynegy Heard Co., GA	25 - NG	? – NG	? - NG	Clean Fuels Good Combustion
Tenaska Heard Co., GA	15 - NG 20 - FO	? – NG ? – FO	? - NG ? lb/hr - FO	Clean Fuels Good Combustion
Dynegy Reidsville, NC	25 - NG 50 - FO	6 lb/hr – NG 8 lb/hr – FO	6 lb/hr - NG 23 lb/hr - FO	Clean Fuels Good Combustion
Lyondell Harris, TX	25 - NG			Clean Fuels Good Combustion
Southern Energy, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
RockGen Cristiana, WI	12@>50% load – NG 15@>75% 24@<75% - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion
Carson Energy, CA	6 – NG			Oxidation Catalyst
McClelland AFB, CA	23 – NG	3.9 - NG	7 lb/hr	Clean Fuels Good Combustion
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 – NG 10 – FO	10% Opacity	Clean Fuels Good Combustion
PREPA, PR	9 – FO @15% O_2	11 – FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

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

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly

with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

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

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

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

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Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not a significant issue for the Midway project because these units will not be continuously operated, but rather will be "peakers". Also, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is proposed to be used for no more than 1000 hours per year (per CT).

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

NO_X Control Techniques

Wet Injection

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

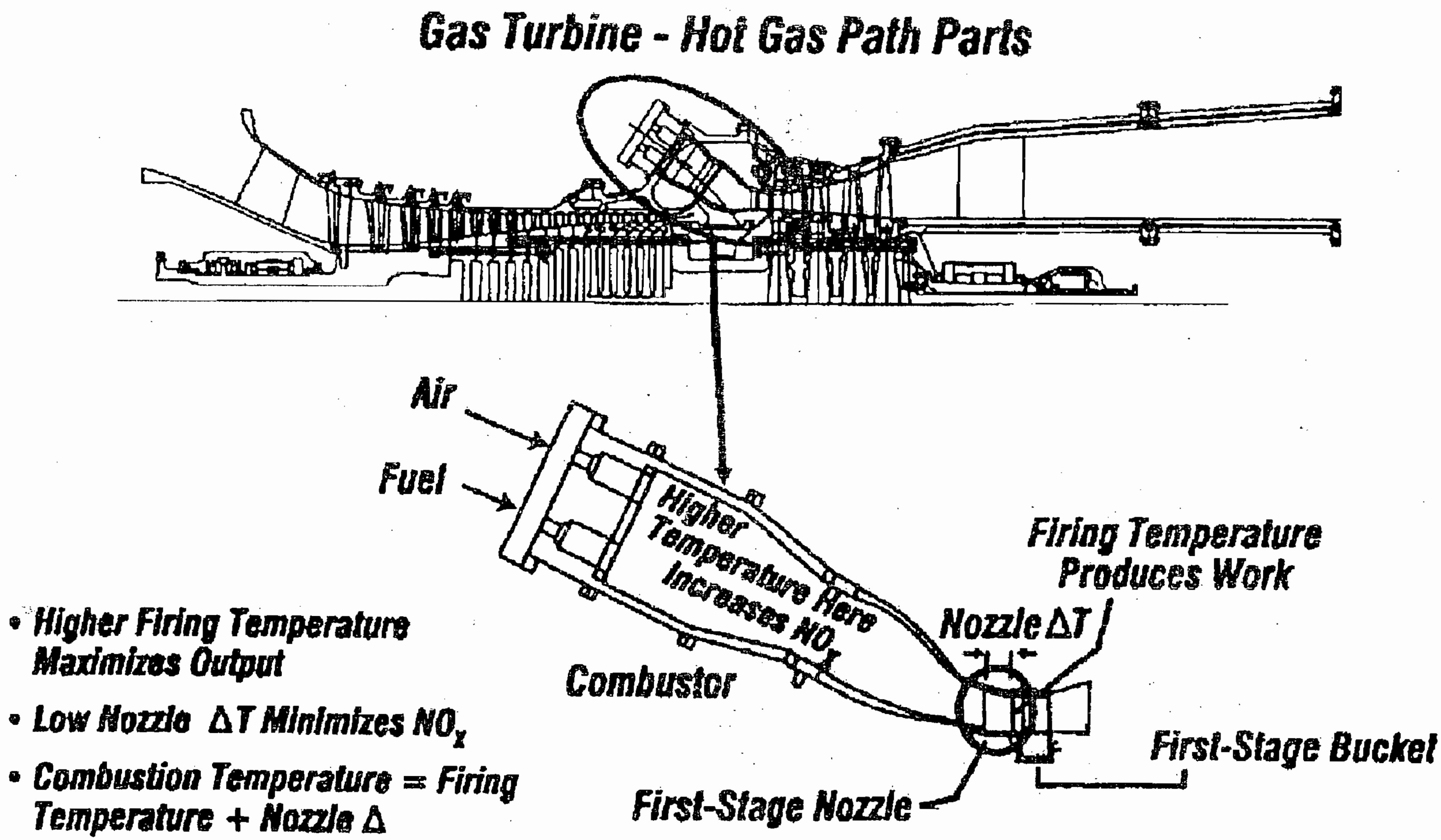

Figure 1 – Relation Between Flame Temperature and Firing Temperature

Combustion Controls

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

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 2. Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quarternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

Design emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X.

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd while burning natural gas. The results are all superior to the emission characteristics given in Figure 3.

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

Emissions characteristics by wet injection NO_X control while firing oil are shown in Figure 4 for the DLN-2.0, a predecessor of the DLN2-6. Operation on fuel oil is not in the premixed mode. Specialized premixed DLN burners for fuel oil operation were installed in a project in Israel[2] where water is scarce, but the Department has no information on the results.

Mitsubishi (who also make a 501F) is also developing a dual-fuel premixed DLN. Optimization of premix fuel-air nozzle and performance was verified in high-pressure combustion tests. Commissioning tests on gas and oil burning were completed at an undesignated site.[3] The details are not available in English.

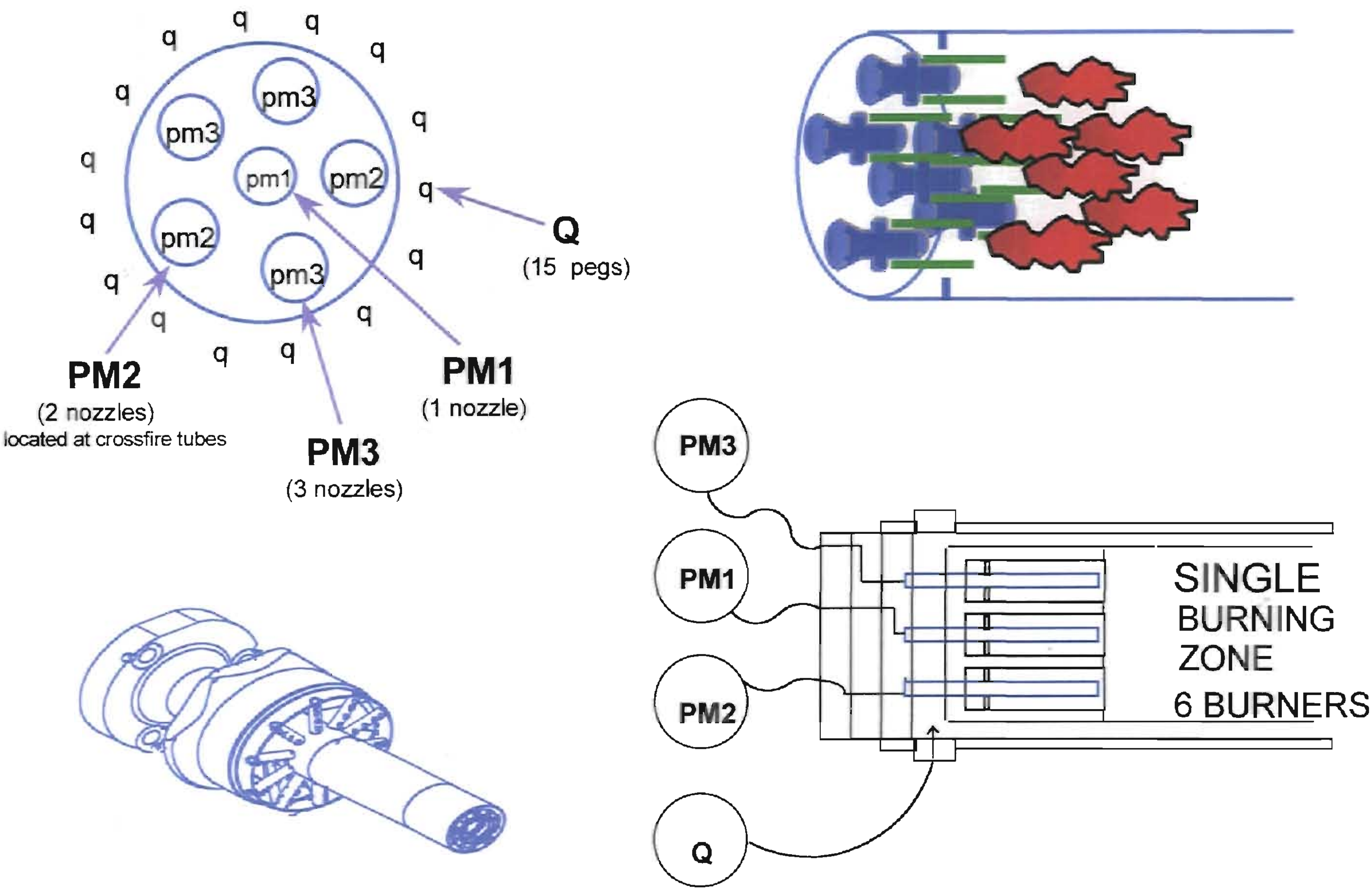

Figure 2 - DLN2.6 Fuel Nozzle Arrangement

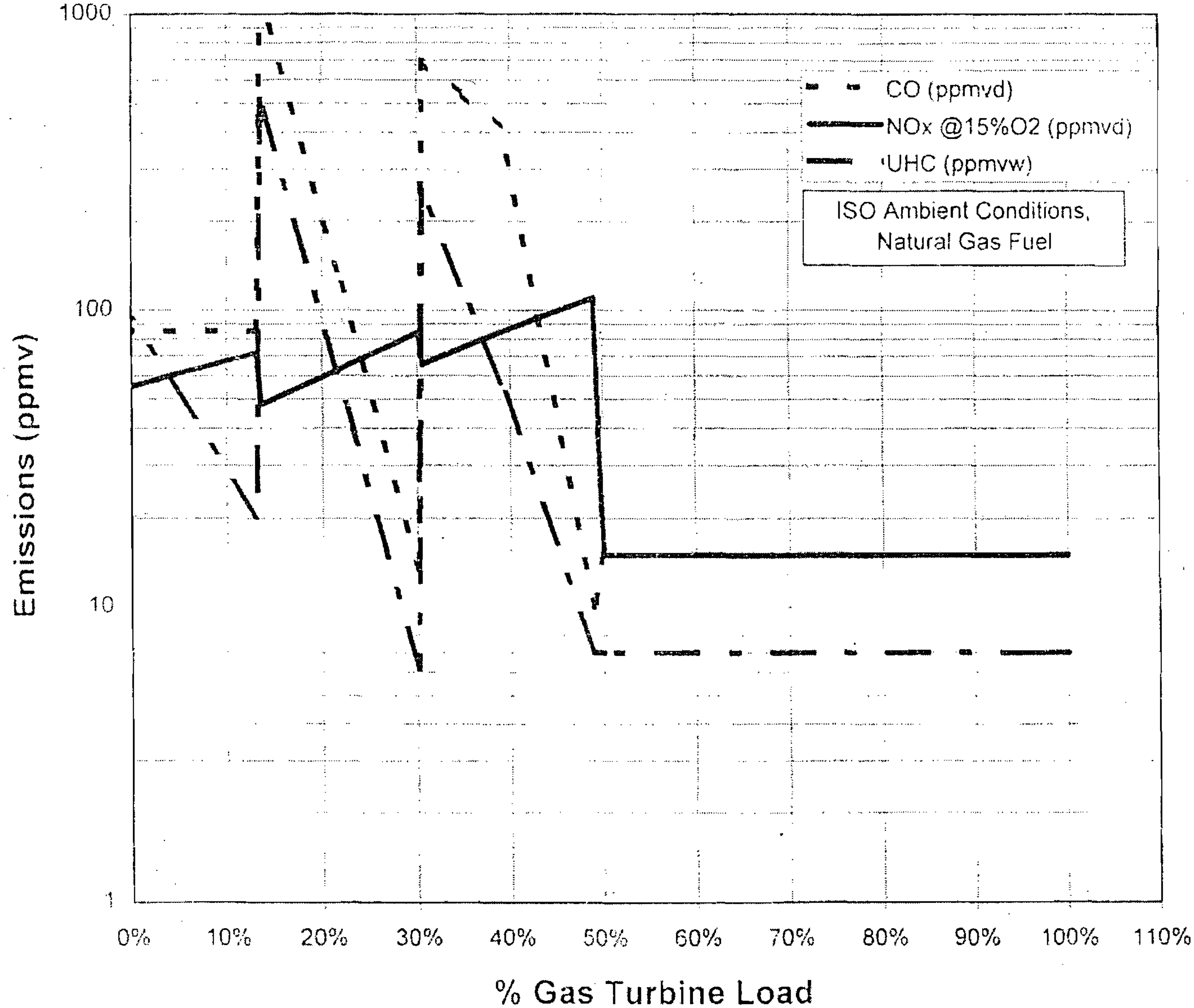

Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

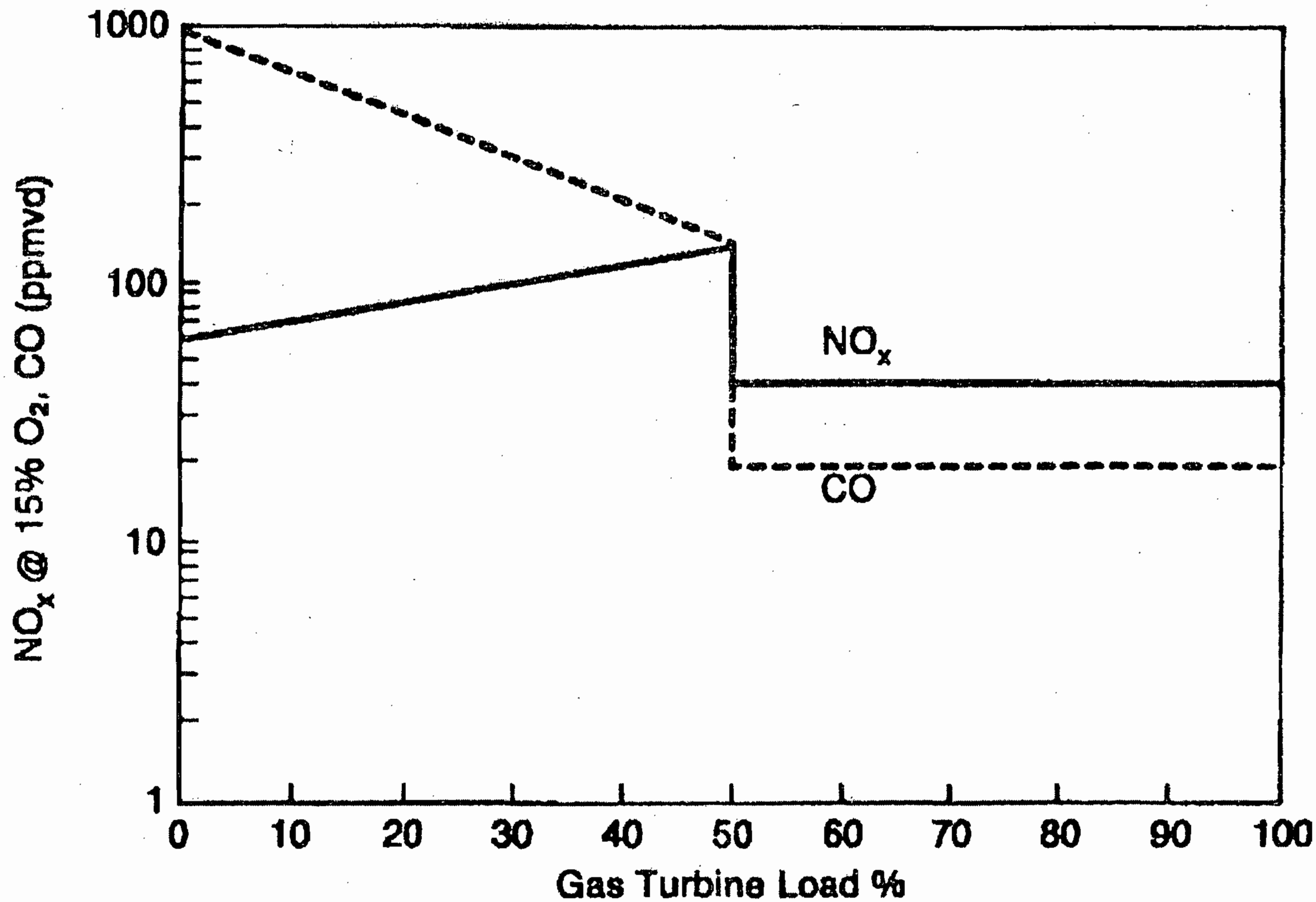

Figure 4 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 5 from an EPRI report.[4] Basically developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 5.

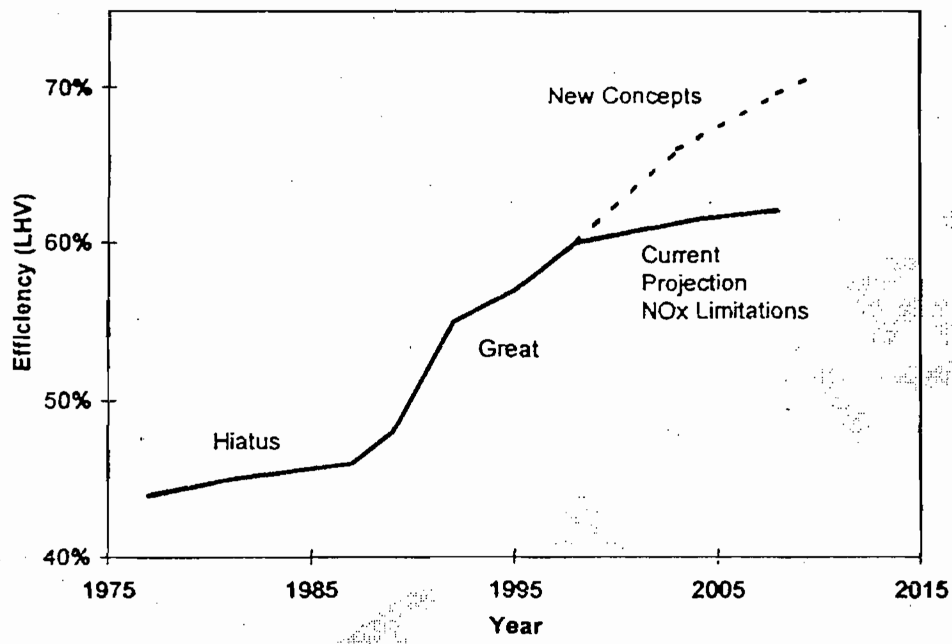

Figure 5 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by Midway. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air-cooling.

Catalytic Combustion: XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[5] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

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

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

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[6] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma which documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

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

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

Selective Catalytic Combustion

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

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

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998.

Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 (Paynes Creek) project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority,[8] FPC, TECO, and Competitive Power Ventures will install SCR on combined cycle projects to achieve 3.5 ppmvd. Limits as low as 2 ppmvd NO_X have been specified using SCR on combined cycle F Class projects in various parts of the country.

Selective Non-Catalytic Combustion

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

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

$SCONO_X$™

$SCONO_X$™ is a catalytic add-on technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[9]

California regulators and industry sources have stated that the first 250 MW block to install $SCONO_X$ ™ will be at PG&E's La Paloma Plant near Bakersfield.[10] The overall project includes several more 250 MW blocks with SCR for control.[11] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine equipped with $SCONO_X$™.

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

Recently EPA Region IX acknowledged that $SCONO_X$™ was demonstrated in practice to achieve 2.0 ppmv NO_X. [12] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmv.

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[13]

$SCONO_X$ requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the $SCONO_X$ system cannot be considered as achievable or demonstrated in practice for this application.

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

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

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 190 TPY of SO_2 and 29 TPY of SAM. The Department expects the emissions to be lower because of the limited oil consumption and the typical natural gas in Florida that contains less than 2 grain of sulfur per 100 standard cubic feet (gr S/100scf). This value is well below the "default" maximum value of 20 gr. S/100 scf; but high enough to require a BACT determination.

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and its use is proposed for only 1000 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. Total annual emissions of PM_{10} for the project are expected to be approximately 119 tons per year.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppm. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review. Seminole Electric recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[14]

Most combustion turbines incorporate good combustion to minimize emissions of CO. So far this appears to be the only technology proposed at simple cycle turbine projects. These installations are typically permitted between 10 and 25 ppmvd at full load while firing gas. The values of 9 and 30 ppmvd for gas and oil respectively at baseload proposed in Midway's original application are within the range of recent determinations for simple cycle CO BACT determinations. Values given in GE-based applications are representative of operations between 50 and 100 percent of full load.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques, particularly for simple cycle combustion turbines. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by Midway for this project are 1.4 ppmvw for gas and fuel oil firing at baseload. These limits are sufficient to keep annual emissions of VOC below the 40 TPY threshold and a BACT determination is not required. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[15]

BACKGROUND ON PROPOSED GAS TURBINE

Midway plans to install three nominal 170 MW General Electric PG 7241FA simple cycle gas turbines. This is the most recent designation of GE's line of "F" Class units.

Typically, companies obtain a guarantee from GE to achieve 9 ppmvd NO_X during a test on a "new and clean unit." The test must be conducted at a steady-state load of 50 to 100 percent and completed within the first 100 fired hours of operation. With the frequent start-ups and shutdowns of the units, some applicants are concerned about the ability to maintain the low NO_X values for long periods of time. As a result, some of them agreed to a "new and clean" limit of 9 ppmvd but requested a continuing BACT limit of 10.5 ppmvd.

As detailed in the table above, the Department has issued quite a number of permits for simple cycle GE 7FA requiring achievement of 9-10.5 ppmvd without the requirement of any additional control equipment. The ones with limits of 9 ppmvd are allowed to operate for as many as 1000 hours per year on back-up fuel oil whereas the ones permitted at 10.5 ppmvd are allowed only 750 hours per year of fuel oil. A smaller GE unit known as the 7EA can routinely achieve 9 ppmvd NO_X or lower based on numerous installations in Florida and elsewhere. The 7EA has a lower flame temperature, compression ratio, and power rating (85 versus 170 MW) than the 7FA.

The ability to meet a NO_X emission limit of 9 ppmvd by DLN technology involves a substantial efficiency and energy penalty as previously discussed. For example, the 7FA is characterized by a 15.5:1 compression ratio, a 2400 °F firing temperature, 56 percent efficiency, and produces 263 MW in combined cycle. On the other hand, GE offers a more efficient F-Class model known as the 7FB, but guarantees a NO_X limit of 25 ppmvd by DLN.

The 7FB is characterized by an 18.5:1 compression ratio, a 2500 °F firing temperature, 57.3 percent efficiency, and produces 280 MW in combined cycle. The clear implication is that the

power penalty to reduce NO_X from 25 to 9 ppmvd by DLN technology alone is on the order of 20 MW for a combined cycle (roughly 13 MW on a simple cycle unit).[16]

Another example of this point is the ABB GT24. It is characterized by a 30:1 compression ratio and 58 percent efficiency in combined cycle. The unit is guaranteed to meet 25 ppmvd of NO_X. The simple cycle version is rated at 183 MW compared to 170 for the GE7FA.

It is not surprising that some compromises were made by ABB, which resulted in greater power and efficiency but slowed progress toward single-digit NO_X emissions. According to ABB, "rather than just concentrating on ever lower NO_X levels, ABB has chosen a total solution that limits pollutants and at the same time increases energy efficiency."[17] A lower compression, lower efficiency version of the ABB GT24 might be capable of 15 ppmvd NO_X or less by DLN technology.

The results during the "new and clean" test of the GE PG7241 at the Polk Power Station (discussed above) are nothing short of spectacular in comparison with the permitted emission limits. It is doubtful that these values can be maintained indefinitely. However, there is good reason to believe that performance will continue to be better than the permitted emission limits. For reference, the values while burning oil were equally good in comparison to the permitted limits for CO and VOC, whereas the NO_X emissions were very close to the permitted value of 42 ppmvd @15% O_2. Visible emissions were 0 percent opacity when firing natural gas or fuel oil.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[18]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Midway project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry volume basis. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions Nos. 18 through 23.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 18/34 lb/hr – Gas/Fuel Oil
CO	As Above	9 ppmvd – Gas 20 ppmvd – Fuel Oil
SO_2/SAM	As Above	2 grain of sulfur per 100 ft^3 gas 0.05 Percent Sulfur in Fuel Oil
NO_X	Dry Low NO_X, WI for F.O., limited oil use	9 ppmvd – Gas 42 ppmvd – F.O. for 1000 of 3,500 hrs

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Top technology and Lowest Achievable Emission Rate (LAER) for simple cycle combustion turbines are Hot SCR and an emission limit of 5 ppmvd NO_X.
- It is conceivable that catalytic combustion technology such as XONON™ can be applied to this project. Theoretically XONON can achieve the 5-ppmvd NO_X value and would equate to the top technology.
- An example of the top technology is the Carson Plant in Sacramento, California where there is a Hot SCR system on a simple cycle LM6000PA combustion turbine with a limit of 5 ppmvd.
- Hot SCR is proposed as LAER for the Sacramento Municipal Utilities District simple cycle GE 7EA project at McClelland Air Force Base to achieve 5 ppmvd.
- Hot SCR is not commonly required as BACT on simple cycle combustion turbines. Although it was required on the fuel oil-fired PREPA project (to achieve 10 ppmvd), the requirement has been removed from the permit. It is noted that the specification of the fuel oil was 0.15 percent sulfur. This does not imply that hot SCR it is not technically feasible for intermittent duty simple cycle combustion turbines firing natural gas with 0.05 percent sulfur fuel oil as back-up fuel.
- Hot SCR is required at the simple cycle continuous duty Lakeland McIntosh Unit 5 project if the Westinghouse 501 G unit fails to achieve 9 ppmvd while firing natural gas. Hot SCR was considered cost-effective because the unit will operate continuously and the expected NO_X reduction is from 25 to 9 ppmvd).
- The levelized costs of NO_X removal by Hot SCR for the Midway Project were estimated by ENSR at $20,700 per ton assuming 3,500 hours of dual-fuel operation. The estimates are based on emissions controlled to 4.5 and 7.5 ppmvd @15% O_2 NO_X while burning gas and fuel oil respectively and 5 ppmvd @15% O_2 ammonia slip.
- The levelized costs of NO_X removal by Hot SCR for the DeSoto project were estimated by Golder at $11,350 per ton assuming 3,390 hours of operation on natural gas and a reduction to 3.6 ppmvd on gas and 17 ppmvd on fuel oil. The estimates are based on an ammonia slip of 9 ppmvd for gas and 12 ppmvd for oil.
- The Department does not accept the precise hot SCR cost calculations presented by Midway and considers them on the high end. The costs calculated by Golder for the DeSoto Project are probably more accurate. With the actual performance of the GE 7FA at TECO Polk Power Station with no add-on control (5-8 ppmvd @15%O_2), it is easy to see that hot SCR would not be cost-effective. Hot SCR is rejected as BACT.
- The Department will limit operation of the three units to 3,500 hours per year per unit. No single unit may operate more than 5,000 hours per year to insure that the conclusion regarding cost-effectiveness remains applicable.
- The units will be operated in intermittent duty and simple cycle mode. Therefore control options that are feasible only for combined cycle units are not applicable. This rules out Low Temperature (conventional) SCR, which achieves 3.5 ppmvd NO_X or lower. It also rules out

the possibility of $SCONO_X$. XONON is available for F Class gas-fired projects. However the status of its development for use in fuel oil or cycling operations is not known.

- General Electric has provided a "clean and new" guarantee of 9 ppmvd NO_X. This value is equal to that required at the Lakeland continuous duty combustion turbine, which has an alternative hot SCR requirement.
- Typical permit limits nation-wide for these GE 7FA units while operating on natural gas and in simple cycle mode and intermittent duty are 9-15 ppmvd even though GE provides the same "new and clean" guarantees for them.
- The 9 ppmvd limit at Oleander, Vandolah, Shady Hills, DeSoto, Virginia Power, and Midway while firing natural gas is the lowest known BACT value for an "F" frame combustion turbine operating in simple cycle mode and intermittent duty. The 42-ppmvd limit for limited fuel oil firing is typical.
- The gas-based NO_X emission limit of 9 ppmvd will be difficult to maintain over short term averaging times. That is the main reason why some operators cannot provide reasonable assurance they can meet such a low limit by DLN. The Department believes a 24-hour averaging time is appropriate. Only periods during which the unit is operated will contribute to the 24-hour average. For example if the unit operates only 6 hours in 24 hours and averages 9 ppmvd during the 6 hours, the reported concentration will still be 9 ppmvd.
- The Department prefers not to set a 24-hour average limit that includes start-up emissions for a peaking unit. There will be a very short period during start-up when emissions might actually exceed 100 ppmvd (see Figure 2). Such periods can probably be absorbed into an emissions limit with a long-term averaging time for continuous duty. It would be much more difficult for an intermittent duty unit that might run only a few continuous hours on occasion.
- The fuel oil-based NO_X emissions limit of 42 ppmvd can be maintained over a short-term averaging period by varying the amount of water injected. The Department has determined that a 3-hour averaging time is appropriate.
- The Department issued permits for the TEC Polk Power, JEA Brandy Branch, and Reliant Osceola Projects with 10.5 ppmvd limit for the same simple cycle GE 7241FA units, but limited the hours of operation on fuel oil to only 750 hours compared with 1000 hours at Oleander, Vandolah, Shady Hills, and DeSoto.
- The proposed BACT limit of 9 ppmvd is less than one-tenth of the applicable NSPS limit per 40 CFR 60, Subpart GG for units as efficient as the 7FA.
- Comments from the National Park Service on the Oleander project suggested that a reduction from 42 to 25 ppmvd in NO_X emissions while burning fuel oil is possible. GE has advised that 42 ppmvd NO_X is the lowest guarantee on F Class units when firing oil. The Department has requested that GE work on developing wet or dry technologies to reduce NO_X emissions for units permitted to fire substantial amounts of fuel oil.[19]
- The Department is aware that ABB offers a DLN technology for fuel oil firing applicable to at least certain smaller combustion turbines (ABB-GTX). It is noted, however, that ABB does not offer a guarantee of 9 ppmvd on the same unit when firing natural gas.

- It is possible that the NO_X emissions while firing oil from may be reduced from 42 ppmvd by increasing the water injection rate. In order to address this possibility, a specific condition will be added to conduct appropriate testing and prepare an engineering report. The report will be submitted for the Department's review to ensure that the lowest reliable NO_X emission rates while firing oil have been achieved.
- The Department's overall BACT determination is equivalent to approximately 0.4 lb/MW-hr by Dry Low NO_X. For reference, the new NSPS promulgated on September 3, 1998 requires that new conventional power plants (based on boilers, etc.) meet a limit of 1.6 lb/MW-hr.
- The applicant estimates VOC emissions of 1.4 ppmvd while firing gas and 1.4 ppmvd while burning fuel oil. The Department will set the limits at 2.8 ppmvd because at this concentration, the project will still not trigger PSD or a requirement for a BACT determination.
- The Department will set CO limits achievable by good combustion at full load as 9 ppmvd (gas) and 20 ppmvd (oil). These values are in the lower range of values from permitted or proposed simple cycle units. These limits are equal to or lower those proposed by the Department for the Oleander, Vandolah, DeSoto, Reliant, JEA Brandy Branch, and TEC Polk Power projects.
- Midway estimated levelized costs for CO catalyst control at $31,800 per ton. The Department does not adopt this estimate, but would agree that even much lower estimates would not be cost-effective for removal of CO.
- Golder evaluated the use of oxidation catalyst for the DeSoto project with 90 percent control efficiency. Golder estimated levelized costs for CO catalyst control at $7,500 per ton.
- The cost of CO control by oxidation catalyst is probably closer to the Golder estimate based on reducing *permitted* CO emissions. However in view of the performance of GE 7FA units without add-on control (~1 ppmvd), it is obvious that oxidation catalyst is definitely not cost-effective based on *actual* emissions and appears to not be cost-effective based on permitted emissions.
- The Department will not set a continuous CO limit reflecting the "new and clean test" because GE will not guarantee it. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state.
- There is no benefit is penalizing the applicant or with a lower limit at this time just because the performance at another site was far better than guaranteed or expected.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; use of clean, low ash, low sulfur fuels, and operation of the unit in accordance with the manufacturer-provided manuals. The emission limits for PM_{10} will be set at 18 pounds per hour during gas operation and 34 pounds per hour while operating on fuel oil. These values include front and back half catch in contrast to the limits for most of the other permitted combustion turbines.

- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, JEA Brandy Branch, TEC Polk Power, Oleander Power, DeSoto Power, Vandolah, Shady Hills and quite a number of combined cycle projects.

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Carbon Monoxide	Annual Method 10
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)
NO_X (gas - 24-hr rolling average) (oil – 3-hr rolling average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed. During gas operation, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C.
SO_2 and SAM	Custom Fuel Monitoring Schedule

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:

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

Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

REFERENCES

1 Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TECO Polk Power Station." September 2000.

2 Telecom. Linero, A.A., FDEP and Chalfin, J., GE. NO_X control technology for fuel oil.

3 Paper. Mandai, S., et. al., MHI. "Development of Low NO_X Combustor for Firing Dual Fuel." Mitsubishi Juko Giho, Vol.36 No.1 (1999).

4 Paper. Cohn, A. and Scheibel, J., EPRI. Current Gas Turbine Developments and Future Projects. October 1997.

5 Compliance Manual. California EPA, CARB Compliance Division. Gas Turbines. June 1996.

6 News Release. Catalytica. First Gas Turbine with Catalytica's XONON installed to Produce Electricity at a Utility. October 8, 1998.

7 News Release. Catalytica. XONON™ Specified With GE 7FA Gas Turbines for Enron Power Project. December 15, 1999.

8 Permit. Florida DEP. KUA Cane Island Unit 3. File PSD-FL-254. November 1999.

9 News Release. Goaline. Genetics Institute Buys $SCONO_X$ Clean Air System. August 20, 1999.

10 "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

11 Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.

12 Letter. Haber, M., EPA Region IX to Danziger, R., GLET. $SCONO_X$ at Federal Cogeneration. March 23, 1998.

13 News Release. ABB Alstom Power, Environmental Segment. ABB Alstom Power to Supply Groundbreaking SCONOX™ Technology. December 1, 1999.

14 Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

15 Telecon. Vandervort, C., GE, and Linero, A.A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."

16 Information Release. General Electric Power Systems. MS7001FB Gas Turbine. Power-Gen. November 1999.

17 ABB Combined Cycle Website. Combustion Turbines. Environmental Burner. www.abbccpp.com.

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

19 Letter. Linero, A. A., FDEP to Forry, J. and Chalfin, J. General Electric. NO_X emissions control while firing fuel oil in Simple Cycle Units. October 12, 1999.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee: **DEP File No.** 1110099-002-AC (PSD-FL-305)

Midway Development Company, L.L.C.
Midway Power Project
St. Lucie County

Project type:

Project is construction of three 170-megawatt GE PG7241FA gas and oil-fired simple cycle combustion turbine-electrical generators with 80-foot stacks, inlet air chillers, two fuel oil storage tanks, a gas heater, and ancillary equipment. Units will operate maximum of 3,500 hours per year per unit of which 1000 hours per year per unit may be on No. 2 distillate fuel oil.

The units must meet the manufacturer's "new and clean" nitrogen oxides performance guarantee of 9 parts per million by volume, dry, at 15% oxygen (ppmvd) while burning natural gas. The continuous (24-hour) BACT NO_X limits are 9 ppmvd when operating on natural gas and 42 ppmvd by wet injection when burning fuel oil. Other pollutants, including particulate matter (PM/PM_{10}), carbon monoxide, volatile organic compounds, sulfur dioxide, and sulfuric acid mist will be controlled by good combustion and use of clean fuels.

Projected impacts from the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I (Everglades National Park) and Class II areas.

***I HEREBY CERTIFY** that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

12/13/00

A A. Linero, P.E. Date
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

A. A. LINERO
CERTIFICATE
NO. 26032
12/13
STATE OF
FLORIDA
REGISTERED ENGINEER

Florida Department of
Environmental Protection

Memorandum

TO: Clair Fancy

FROM: Al Linero *Al Linero 12/13*

DATE: December 13, 2000

SUBJECT: Midway Energy Center
Three 170 MW Combustion Turbines
DEP File No. 1110099-002-AC (PSD-FL-305)

Attached is the public notice package for construction of three dual-fuel, intermittent duty, simple cycle, 170 MW combustion turbines with inlet air chillers, two fuel oil storage tanks, a gas heater, and ancillary equipment at the planned (Enron) Midway Energy Center.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by Dry Low NO_X (DLN-2.6). The applicant proposed an NO_X emission limit of 9 ppmvd @15% O_2. We are requiring compliance on a <u>continuous</u> (24-hour average) basis. The use of fuel oil will be allowed up to 1000 hours per year per unit in recognition of the very low simple cycle NO_X limit on gas.

The NO_X and fuel oil hours are equal to the values in the Oleander and IPSAPC Vandolah, DeSoto and Shady Hills permits. For reference, JEA Brandy Branch, TECO Polk, and Reliant were allowed 10.5 ppmvd NO_X on gas, but only 750 hours per year per unit of operation on fuel oil.

NO_X emissions will be controlled to 42 ppm during the limited fuel oil use. Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and, especially, the design of the GE unit.

For reference, recent testing at TECO Polk Power Station indicated that these units achieve between 5 and 8 ppmvd NO_X under natural gas firing when tested as "new and clean" units. The TECO unit also achieved about 1 ppmvd of CO. Nevertheless, Enron has doubts about meeting a 9 ppmvd limit on a continuous basis. It is possible that we will increase the NO_X limit but reduce fuel oil firing based on comments during the public notice period.

I recommend your approval of the attached Intent to Issue.

AAL/al

Attachments

Memorandum

Florida Department of Environmental Protection

To: Joseph Kahn

From: Dave Pocengal

Date: December 11, 2000

Re: Testing and CEMS Requirements for Permit PSD-FL-305

The following comments are provided based upon a review of the above permit items 20 through 48:

20. In the emission limits and control technology chart, the sulfur limit in the PNG is listed as 1 gr S/100 ft^3 for SO_2 and SAM. Item 24 states this limit to be 2 gr S/100 ft^3. Also, the CO and VOC limits in items 22 and 23, respectively, do not coincide with those listed in the chart.

21. For reporting purposes, it does not appear necessary to include NO_x emissions calculated as NO_2. EPA Methods 20 and 7E base the measurement of NO_x on the measurement of NO. NO is used as the calibration gas and NO_x chemiluminescent analyzers measure NO, converting NO_2 to NO before the detector.

22. See (20) above.

23. Method 25A should replace Method 25 as stated in item 31. Also, see (20) above.

24. See (20) above. Also, units of 'lb/hr' left out after '16' (p.10 line 3).

32. Include 'fuel switching' in "Valid hourly emission rates shall not include periods of…."?

33. The method used for compliance is not mentioned in the 1st sentence. (Determination of sulfur content in gas or oil?) No guidance was provided for determining the sulfur content of fuel oil--should ASTM D 2880-71 be mentioned for this purpose or does item 47 cover this?

45. Since this unit is subject to the Title IV Acid Rain provisions, CEMS certification and QA procedures are required pursuant to 40 CFR 75. In many cases, 40 CFR 60 requirements are cited in 40 CFR 75 and the two may intersect in many instances. Possible language: "The continuous emission monitoring system shall be installed, certified, operated, and maintained according to 40 CFR 75.20. The owner or operator shall develop and implement quality assurance and quality control procedures pursuant to 40 CFR 75.21 and 40 CFR 75, Appendix B. Each monitoring component shall comply with the performance specifications of 40 CFR 60, Appendix B as demonstrated by the testing procedures of 40 CFR 75, Appendix A."

47. Consider the following language regarding sulfur content testing of fuel oil: "The owner of operator shall determine the sulfur content of each delivery of diesel fuel received for these

emissions units using ASTM D 4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products; and one of the following test methods for sulfur in petroleum products: ASTM D 129-91, ASTM D 2622-94 or ASTM D 4294-90. These methods are adopted by Rule 62-297.440, F.A.C. The owner or operator may comply with this requirement by receiving records from the fuel supplier that indicate the sulfur content of the fuel delivered complies with the sulfur limit of specific condition 24 of this section. [Rule 62-4.070(3) and 62-297.440, F.A.C.]

Other

- If the unit is allowed to operate in high performance mode (HPM), include applicable criteria.

- Should an initial compliance test for PM be performed? Method 5 or 17.

- Subpart GG [40 CFR 60.335(c)(3)] states that for initial compliance testing Method 20 shall be used to measure NO_x concentrations using a span of 300 ppm. Under 40 CFR 60.8 it may be possible to establish a lower span setting as 10 ppm on a range of 300 ppm may approach the analyzer noise level. However, the facility may be reluctant to adjust the span down for their own purposes.

Come by my office or call me at 921-9577 if you have any questions.

DP/dp

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

CERTIFIED MAIL

December 5, 2000

Mr. Alvaro A. Linero, P.E.
Administrator, New Source Review Section
Bureau of Air Regulation, Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: DEP File No. 1110099-002-AC (PSD-FL-305)
Midway Energy Center, St. Lucie County

Dear Mr. Linero:

On behalf of Midway Development Company, LLC, an application was filed on November 7, 2000 with the Florida Department of Environmental Protection (DEP), for a 510 megawatt (MW) dual fuel peaking power plant. The Midway Energy Center is proposed to consist of up to three General Electric PG7241FA combustion turbine generators.

After consideration of the filed application and subsequent discussions with the Department, it is our intent to revise our application in order to conform with other dual fuel peaking plant permits that have been issued. Specifically, we would like to make the following changes.

- Reduce the total hours requested for distillate oil use from 1500 hours per turbine annually to 1,000 hours per turbine.
- Reduce the requested NOx emission limit while firing natural gas from 12 ppm @ 15% O_2 to 9 ppm @ 15% O_2. It is our understanding that this concentration limit will be based on a 24-hour block average of the hours that the units operate, exclusive of startup, shutdowns, and malfunctions.

In addition to these changes, we will be modifying our permit application to reflect revised assumptions to be used in the estimation of cost effectiveness in the BACT analysis. Specifically, this will affect the cost effectiveness calculations for the carbon monoxide catalyst and hot selective catalytic reduction for NOx. These revised cost estimates will reflect recent discussions between ENSR with Department personnel regarding the Pompano Beach permit application.

Please contact Dave Kellermeyer of Enron North America (713-853-3161) or Bob Iwanchuk of ENSR (978-635-9500) with your questions and comments.

Sincerely,
Enron North America

David A. Kellermeyer

David A. Kellermeyer
Director

Cc: Bob Iwanchuk, ENSR
Dave Kellermeyer, Enron North America
Greg Krause, Enron North AmericA
C. Carlson
L. Anderson
EPA
NPS

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 17, 2000

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Midway Development Company, L.L.C.
Midway Energy Center, St. Lucie County
PSD-FL 305
Facility ID No. 1110099-002-AC

Dear Mr. Bunyak:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Midway Development Company, L.L.C., proposes to construct and operate a power generating facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact me at 850/921-9523.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosures

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 17, 2000

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA – Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Midway Development Company, L.L.C.
Midway Energy Center, St. Lucie County
PSD-FL 305
Facility ID No. 1110099-002-AC

Dear Mr. Worley:

Enclosed for your review and comment is an application for construction of a PSD source. The applicant, Midway Development Company, L.L.C., proposes to construct and operate a power generating facility in St. Lucie County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact me at 850/921-9523.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosures

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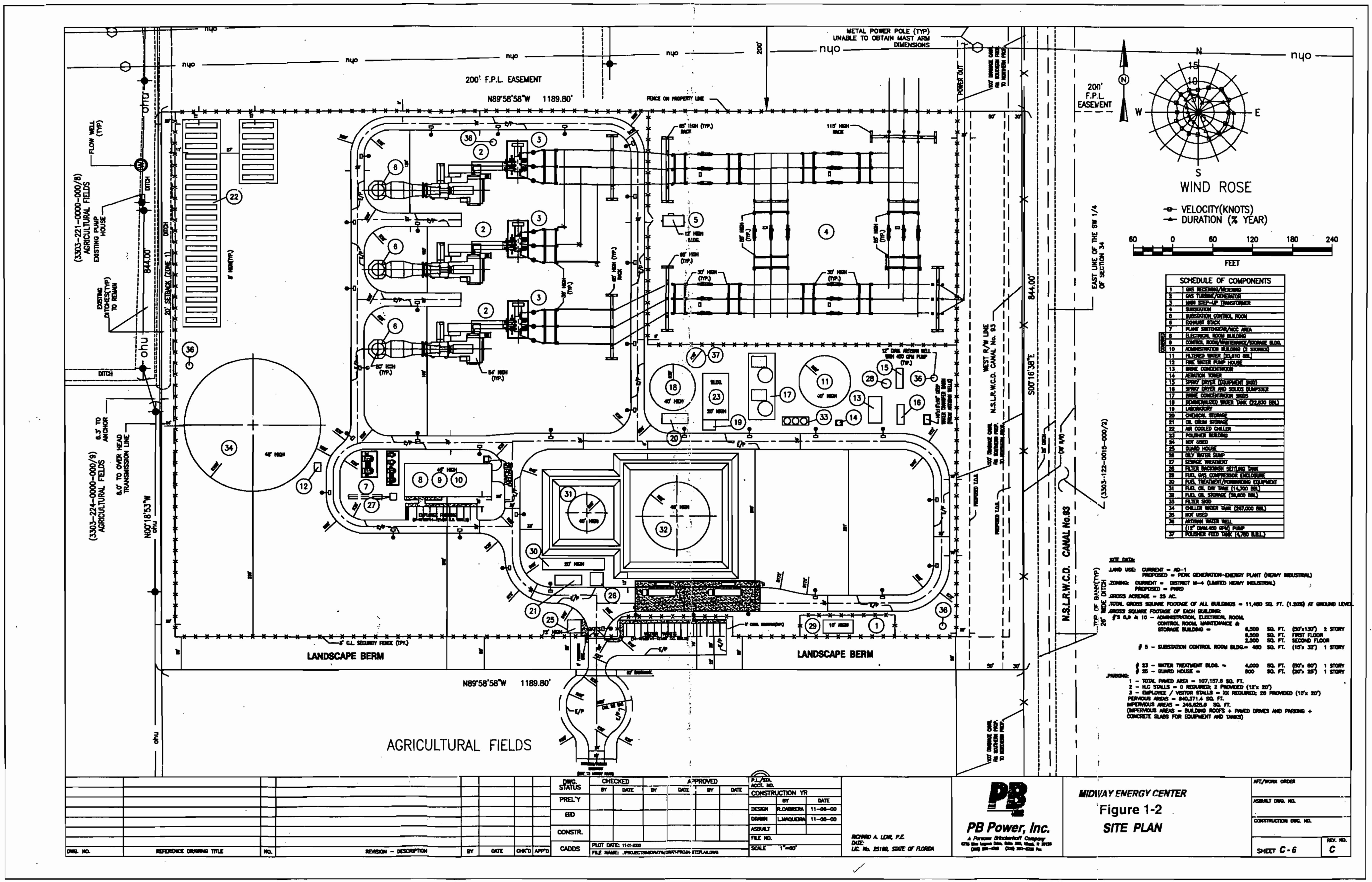

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

November 7, 2000

RECEIVED
NOV 09 2000
BUREAU OF AIR REGULATION

Mr. Al Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Midway Development Company, LLC
Permit Application for Midway Energy Center

Dear Mr. Linero:

On behalf of Midway Development Company, LLC, enclosed are four (4) copies of an air permit application for the Midway Energy Center in St. Lucie County, Florida. This application is for a PSD permit for a simple cycle combustion turbine power plant consisting of 3 General Electric 7FA dual-fuel units. Also enclosed is a CD-ROM containing the modeling archive required for your review. A Separate copy of this application is being sent to the Southeast District of the Florida DEP. An application processing fee has not been enclosed. Due to previously-submitted and withdrawn applications, Enron North America believes that it has an existing positive fee balance with the Florida Department of Environmental Management.

If you have any questions, please don't hesitate to call me at (713) 853-3161.

Sincerely,
Enron North America

David A. Kellermeyer

David A. Kellermeyer
Director

Enclosures

cc: Mr. Lennon Anderson, Southeast District

Midway Development Company, L.L.C.

RECEIVED
NOV 09 2000
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Houston, TX

PSD Permit Application for the Midway Energy Center

ENSR International
November 2000
Document Number 6792-140-300

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1.0 INTRODUCTION

1.1 Application Summary

Midway Development Company, LLC is proposing to construct and operate a 510 MW (nominal) simple-cycle combustion turbine peaking electric generating facility in St. Lucie County. The facility, to be known as the Midway Energy Center (MEC), will be located on approximately 30 acres of property near Port St. Lucie, Florida. From an air emissions perspective, the key elements of the proposed action include:

- Three (3) combustion turbines;
- Natural gas fuel heater; and
- Two distillate oil storage tanks.

Midway Development Company, LLC desires to commence construction in April 2001 and begin commercial operation no later than May 1, 2002 (pending receipt of all necessary local and environmental approvals).

Since the proposed action will be a major stationary source under the Part C of the Clean Air Act, MEC is applying to the Florida Department of Environmental Protection (FDEP) for a Prevention of Significant Deterioration (PSD) permit and for a State Air Construction Permit. This application provides technical analyses and supporting data for a permit to construct the facility under the federal PSD program, as well as the state construction permit program. The federal PSD program in Florida is administered by the FDEP under a State Implementation Plan program approved by U.S. EPA under 40 CFR 51.166.

This application addresses the air construction permitting requirements specified under the provision of Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The application is divided into seven additional sections. Section 2.0 presents an overview of the proposed action and processes covered by this permit application. Section 3.0 describes the methods used to calculate facility emissions and provides a summary of expected emissions. Section 4.0 reviews the regulatory requirements with which the facility must comply. Section 5.0 presents a control technology evaluation for those pollutants subject to PSD review. Section 6.0 presents the air dispersion modeling analysis required by PSD and FDEP regulations. Finally, Section 7.0 provides the additional impacts analysis required by PSD regulations.

FDEP application forms are located in Appendix A. Supporting emission calculations are presented in Appendix B. Information supporting the control technology review is presented in Appendix C. BPIP output data for establishing modeling downwash parameters is presented in Appendix D. Appendix E provides a description of the dispersion modeling input data and output files, which have been submitted to FDEP on CD-ROM.

General information about the applicant and the location of the project site, are presented below. A more detailed discussion on the organization of this document is also presented. To facilitate FDEP's review of this document, individuals familiar with both the facility and the preparation of this application have been identified in the following section. FDEP should contact these individuals if additional information or clarification is required during the review process.

1.2 General Applicant Information

Listed below are the applicant's primary points of contact, and the address and phone number where they can be contacted. Since this permit application has been prepared by a third party under the direction of Midway Development Company, L.L.C., a contact has been included for the permitting consultant.

1.2.1 Applicant's Address

Corporate Office	Midway Development Company, LLC 1400 Smith Street Houston, TX 77002-7631
Project Site	Midway Energy Center Northwest of the intersection of I-95 and W. Midway Rd. St. Lucie County (Port St. Lucie approximately 1.5 km to the southeast)

1.2.2 Applicant's Contacts

Corporate Officer	Ben Jacoby Director 1400 Smith Street Houston, TX 77002-7631
Environmental Contact	Dave Kellermeyer Director 1400 Smith Street, EB-2957 B Houston, TX 77002-7631 Telephone: (713) 853-3161 Fax: (713) 646-3037

Permitting Consultant

Robert Iwanchuk
Project Manager
ENSR
35 Nagog Park
Acton, MA 01720
Telephone (978) 635-9500 X3265
Fax (978) 635-9180

1.3 Project Location

The Midway Energy Center will be located on an approximately 30-acre parcel of rural land located in St. Lucie County, Florida. The site is located northwest of the intersection of I-95 and W. Midway Road. The facility will be connected to electrical transmission lines and a natural gas pipeline located in close proximity to the site. The approximate project property boundary and local road network is shown on Figure 1-1. A detailed representation of the property boundary is shown on the plot plan drawing contained in Figure 1-2. The site exhibits low topographic relief and is currently occupied by an abandoned citrus grove. Stormwater will be handled by the facility's storage water management system, which includes one on-site stormwater detention pond.

Benchmark Universal Transverse Mercator (UTM) coordinates for the plant, corresponding to the middle combustion turbine stack location shown in Figure 1-2 and the power island grade elevation are as follows:

Zone Number	17
Northing (m)	3,028,548
Easting (m)	556,670
Site Elevation (ft msl)	20

1.4 Document Organization

The balance of this document is divided into sections which address the major issues of a preconstruction air quality permit review. The outline below provides an overview of the contents of each of the remaining sections.

- **Section 2.0 - Project Description** provides an overview of the facility including major facility components. A general description of the Simple-Cycle process by which power will be produced at this site is presented.
- **Section 3.0 - Emissions Summary** presents a detailed review of the emissions which will be generated at the project site subsequent to the completion of project development, under normal operating conditions. The basis and methods used to calculate emissions from the project are presented.

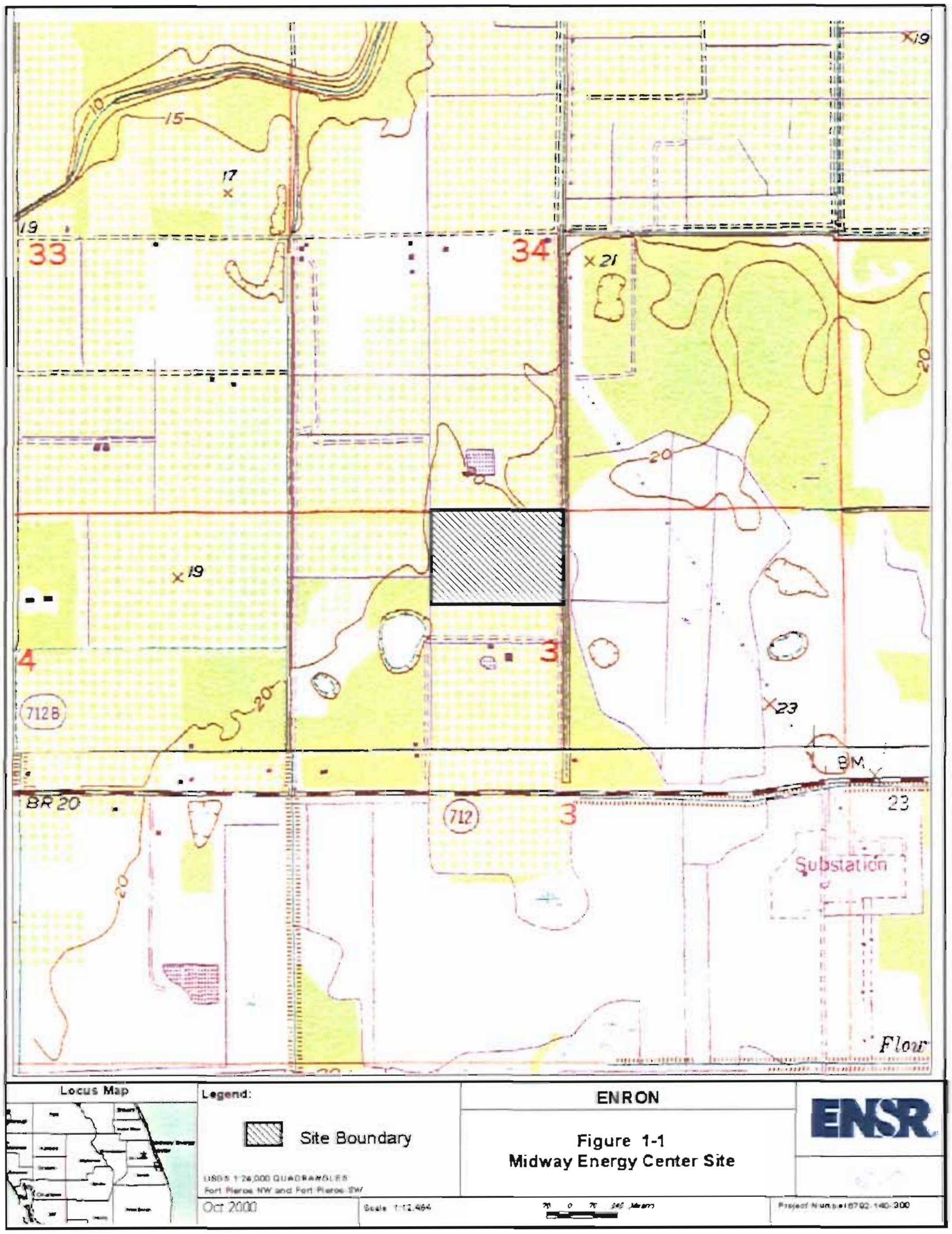

Figure 1-1
Midway Energy Center Site

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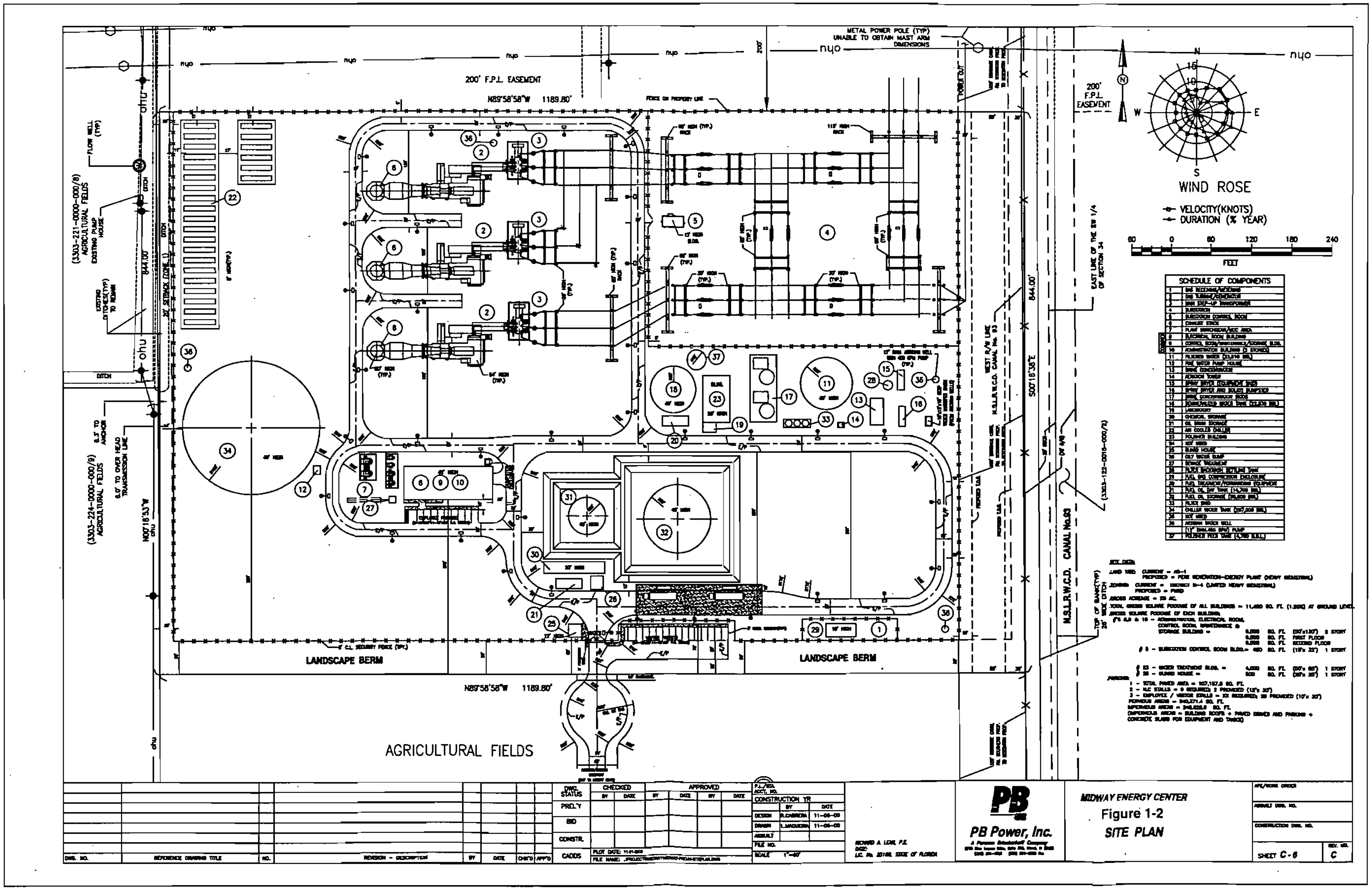

- **Section 4.0 - Applicable Regulations and Standards** presents a detailed review of both Federal and State regulations. The focus of this section will be on establishing which regulations are directly applicable to the proposed project and for which compliance must be demonstrated.

- **Section 5.0 - Control Technology Evaluation** is a substantial requirement for the PSD application. Since the proposed project will result in a significant increase in the emission of certain criteria pollutants, as defined under PSD regulations, a detailed review of control technologies is provided. Annual "Potential-to-Emit" (PTE) emissions, as defined by FDEP, are expected to be significant for Carbon Monoxide (CO), Particulate Matter (PM\PM_{10}), Sulfur Dioxide (SO_2) Nitrogen Oxides (NO_x) and Sulfuric Acid Mist (H_2SO_4). Therefore, control technology analyses for these pollutants have been prepared. The review conforms to the EPA's Top-Down protocol.

- **Section 6.0 - Air Dispersion Modeling Analysis** provides the results of the air quality impact assessment required under the PSD regulations to demonstrate compliance with National Ambient Air Quality Standards (NAAQS), PSD Class II Increments, and the significant impact levels defined for them. The air quality impact analysis predicted no significant impacts; therefore no further modeling for compliance with the NAAQS and PSD increments was required. The air dispersion modeling was done in conformance with EPA modeling guidelines.

- **Section 7.0 - Additional Impacts** contains supplemental information regarding the potential impacts of the project. Specifically this section discusses the potential for impacts on local soils, vegetation, visibility, and growth related air quality impacts. PSD Class I area assessments of regional haze, increment and deposition impacts using the CALPUFF dispersion model will be submitted as a supplement to this permit application.

- **Section 8.0 - References** include a list of the documents relied upon during the preparation of this document.

- **Appendix** - Permit application forms, emission calculations, and supplemental materials supporting the information presented herein are contained in the appendices to this document. Modeling results, both input and output files, are provided on the enclosed CD-ROM.

2.0 PROJECT DESCRIPTION

The following section provides an overview of the facility addressed by this permit application. The facility will be owned and operated by Midway Development Company, LLC. The proposed project is a dual fuel Simple-Cycle merchant power plant to be located near Port St. Lucie, Florida. A merchant power plant is a non-utility generation facility designed to produce power within the emerging deregulated electricity market. The Midway Energy Center is designed to have a nominal generating capacity in the range of 510 MW. Commercial operation is scheduled to commence by May 1, 2002. As a merchant plant in a deregulated electricity market, the MEC is being designed to convert fuel to useful power quickly, cleanly, and reliably.

2.1 Power Generation Facility

The MEC will include three (3) General Electric 7FA combustion turbine generators (CTGs) operating in Simple-Cycle mode. The CTGs will be designed to operate on both natural gas and low-sulfur diesel oil. Dry, low NO_X combustors will be used to minimize NO_X formation during combustion, and water injection will be employed during diesel oil-firing to reduce NO_X emissions. Each turbine will be equipped with its own exhaust stack.

The proposed generation facility will utilize the Best Available Control Technology (BACT), as defined by U.S. EPA, for NO_X, CO, SO_2, Sulfuric Acid Mist, and PM/PM_{10} to minimize air emissions. The project will not be a major source of hazardous air pollutants.

2.2 Major Facility Components

The primary source of criteria pollutants associated with the MEC are the three combustion turbine generators which exhaust through three separate stacks. A process flow diagram for a simple-cycle combustion turbine is shown in Figure 2-1. There will be a minor amount of emissions associated with the plant's ancillary facilities, including the two diesel fuel storage tanks and a fuel gas heater. A brief description of the major components of the facility is provided in the following sections.

Operating parameters for the combustion turbine at three loads (100%, 75%, 50%), and four ambient temperatures (30°F, 42°F, 50°F, 91°F), are presented in Appendix B. This covers the expected operating range of the facility.

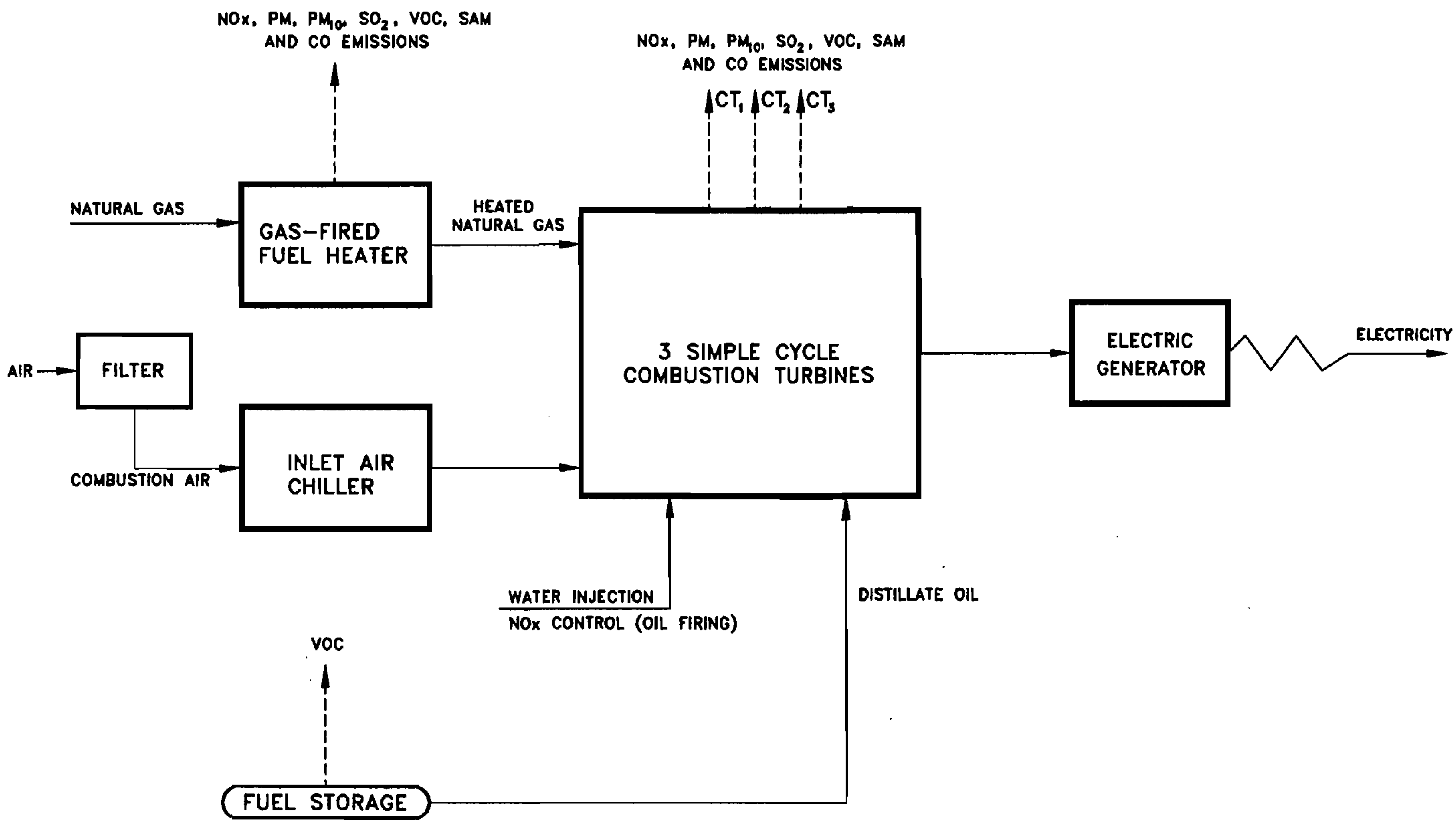

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FIGURE 2-1

PROCESS FLOW DIAGRAM

SIMPLE CYCLE COMBUSTION TURBINE
MIDWAY ENERGY CENTER

DRAWN: JK	DATE: 10/00	PROJECT NUMBER:	REV.
APPV'D: DD	REVISED: X	6792-140	0

679209A.DWG

2.2.1 Gas Turbines

MEC proposes to install three (3) General Electric combustion turbine generators in Simple-Cycle mode with independent exhaust stacks. Each turbine will include an advanced firing combustion turbine air compressor, gas combustion system (dry, low NO_X combustors), power turbine, and a 60-hertz (Hz), 13.8 kilovolt (kV) generator. The turbines will run predominantly on pipeline-quality natural gas, but will have the capability to operate on diesel oil. Each turbine is designed to produce a nominal 170 MW of electrical power.

The power output from a combustion turbine generator (CTG) is proportional to the mass flow rate of air and fuel through the expansion (power) turbine. Thus at high ambient temperatures the power available from a CTG is significantly reduced due to the lower density of the inlet air. As the CTG's proposed are intended to provide peak power generation, in an area where ambient temperatures frequently rise above 80°F, the CTG's have been equipped with inlet air chilling equipment. At high ambient temperatures, inlet air chillers will be operated to cool the inlet air to the turbines in order to compensate for the loss of power output due to lower compressor inlet density. At an ambient temperature of 91°F, chilling will reduce the compressor inlet temperature to 50°F resulting in an approximately 24 MW increase in gross power output per CTG unit. The inlet air chillers will operate using a closed loop cooling circuit, with waste heat exhausted to the atmosphere using dry, air-cooled cooling towers. These cooling towers will be of a non-contact design and thus do not represent a source of air emissions.

The gas turbine is the heart of a Simple-Cycle power system. First, air is filtered and compressed in a multiple-stage axial flow compressor. Compressed air and natural gas are mixed and combusted in the turbine combustion chamber. Dry, low NO_X combustors and water injection are used to minimize NO_X formation during combustion, depending on which fuel is fired. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine which drives both the air compressor and electric generator. The exhaust exits the power turbine at atmospheric pressure and approximately 1,100°F.

2.2.2 Simple-Cycle

The MEC will use Simple-Cycle power generation technology to deliver electrical peaking power during periods when short-term demand exceeds base load requirements. Peaking power units are able to be brought on and off-line quickly, in response to nearly instantaneous fluctuations in electricity demand.

2.2.2.1 The Brayton "Simple" Cycle

The production of electricity using a combustion turbine engine coupled to a shaft driven generator is referred to as the Brayton Cycle. This power generation cycle has a thermodynamic efficiency which generally approaches 40%. This is also referred to as "Simple-Cycle" and has been traditionally utilized for electricity peaking generation since the turbine(s) and subsequent electrical output can be brought on line very quickly. The largest energy loss from this cycle is from the turbine exhaust in which heat is discarded to the atmosphere at about 1,100°F.

2.2.3 Fuel Gas System

Pipeline-quality natural gas is delivered to the plant boundary at a sufficient pressure so that no additional fuel compression will normally be required. If gas compression is required, it will be accomplished using an electrically-driven compression system. The gas is first sent through a knockout drum for removal of any large slugs of liquid which may have been carried through from the pipeline. Only one knockout drum is provided.

The natural gas then passes through a filter/separator to remove particulate matter and entrained liquids. The gas flows through the filter/separator's first chamber, the filtration section, where entrained liquid is coalesced on the filter cartridges, drops to the bottom of the chamber and either vaporizes and returns to the main gas stream or drains to the sump below. The gas then flows through the coalescing filters which remove any particulate matter. Next, the gas passes to the second chamber, the separation section, where any entrained liquid remaining in the stream is further separated by impingement on a net or labyrinth and drains to the bottom sump.

The gas is then heated by a natural gas-fired heater, prior to being split for distribution to the three GE turbines. The fuel gas heater is designed for use as a means to prevent condensation of moisture and hydrates in the natural gas used in the CTGs. Each stream is sent through one last knockout drum to protect against the presence of liquid in the fuel. Finally, the gas is delivered to the turbines and combusted as part of the power generation cycle.

2.2.4 Distillate Oil Storage

Diesel fuel will be provided by tanker trucks and stored in two, above-ground storage tanks made of steel. These tanks will also supply fuel to the combustion turbines during diesel oil-firing. On site oil storage requirements have been estimated to be a maximum of 2.5 million gallons, with a maximum day storage tank requirement of 0.6 million gallons.

2.2.5 Ancillary Facilities

Other systems supporting plant operations and safety include:

- Auxiliary Cooling Water System
- Fire Protection System

- Service Water System
- Process Waste Water System
- Potable Water and Sanitary Waste Water System
- Storm Water System
- Plant and Instrument Air System
- Continuous Emissions Monitoring System (CEMS)
- Maintenance Lifting System
- Unit Control System

3.0 PROJECT EMISSIONS

This section discusses the basis and methods used to calculate emissions for the MEC. The section is organized according to the primary emission source groups. Within each section the methods used to calculate emissions and any adjustments that are required appear first, followed by a summary of the emissions resulting from the specific operation or activity.

The calculation procedures used during the development of this application rely on process information developed by MEC for the operations to be conducted at the MEC, manufacturers' data, and methods presented by the U.S. EPA in the "Compilation of Air Pollution Emission Factor, AP-42". The summary presented below has been prepared for each major emission-generating component of the proposed project, which includes:

- Combustion Turbines (3 Units);
- Natural gas fuel heater; and
- Fugitive Emissions from distillate oil storage .

Detailed emission calculations for each emission source or source category are presented in Appendix B.

3.1 Combustion Turbines

3.1.1 Criteria Pollutants

Criteria pollutant emissions are those that contribute to the formation of ambient air concentrations of pollutants for which the EPA has established National Ambient Air Quality Standards (NAAQS) based on health effects criteria. The PSD-regulated criteria pollutant emissions associated with natural gas combustion are CO, NO_X, VOC, SO_2, and Particulates (PM/PM_{10}). The only PSD-regulated non-criteria pollutant expected to be emitted in significant quantities is sulfuric acid mist (SAM).

The primary emission sources at the MEC will be the three(3) combustion turbines. Hourly emissions from these units were calculated from manufacturers' operating parameters and guaranteed in-stack concentrations for CO, NO_X, and VOC. SO_2 emissions were calculated using the manufacturers' supplied fuel consumption data and fuel gas sulfur content. Particulate emissions include front-half and back-half particulate matter as measured by EPA Methods 5 and 202.

Maximum hourly emission rates for each compound are based on the type of fuel fired, the four ambient temperatures, and the three turbine load conditions (100%, 75%, and 50%) that represent the range of expected operating conditions. Annual emissions are based on the hourly emission rates for the worst-case loads during both natural gas and distillate oil-firing at an ambient temperature of 50°F (the inlet temperature for the majority of expected operating hours during the summer with inlet chilling). Annual emission estimates for NO_X, CO, VOC, SO_2, and PM/PM_{10} are calculated using a worst-case operating schedule of:

- 3,500 hours total operation per turbine, considering both natural gas and distillate oil;
- up to 3,500 hours of operation per year per turbine on natural gas; and
- 1,500 hours of operation per year per turbine on distillate oil.

The PSD permit will limit each turbine to 3,500 hours of operation per year.

The data used in this analysis is presented in Appendix B. Table 3-1 presents a summary of worst-case hourly emissions for the three combustion turbines. Table 3-2 presents a summary of estimates of annual potential emissions.

3.1.2 Non-Criteria Pollutants

Non-criteria pollutant emissions include PSD-regulated non-criteria pollutants and pollutants regulated by U.S. EPA under the National Emissions Standards for Hazardous Air Pollutants (NESHAPS). Estimates of Sulfuric Acid Mist and Lead emissions are included in tables 3-1 and 3-2, and have been prepared using the same calculation methodology as presented for PSD-regulated criteria pollutants.

An estimate of total Hazardous Air Pollutants emissions has also been performed. The calculation procedures used during the development of this application rely on process information developed for the proposed project, manufacturers' data and emission factors presented by U.S. EPA in the "Compilation of Air Pollution Emission Factor, AP-42". The summary presented below has been prepared for each source category identified previously. Detailed emission calculations for each emission source or source category are presented in Appendix B.

The primary emission sources at the MEC will be the three (3) combustion turbines. Hourly emissions from these units were calculated using the manufacturers' fuel feed rate (as MMBtu/hr). Emission factors were derived from one of two sources: 1) Section 3.1 of AP-42 or 2) information from the California Air Resources Board (CARB) CATEF database. The source of emission factors for each pollutant is identified in the Appendix B.

Maximum hourly emission rates for each compound were established using the highest hourly fuel feed rate (as MMBtu/hr, Higher Heating Value (HHV)) for the three load and the four ambient temperature conditions identified above. Annual emissions were based on the hourly fuel feed rate for 50°F, 100% load and 3,500 hours of operation with up to 1,500 hours of distillate oil operation. Table 3-3 presents a summary of emissions for the combustion turbines and the fuel heater.

Table 3-1 Hourly Emission Rate Summary for the MEC Combustion Turbines

Compound	Load (%)	Temperature (°F) 91	50	42	30
Emissions for One GE 7FA Turbine – Natural Gas Operation					
NO_x	100	71.4	79.5	80.5	82.1
	75	58.0	63.4	64.1	65.3
	50	45.9	50.3	50.8	51.6
CO	100	26.5	29.6	30.1	30.9
	75	21.8	23.5	23.8	24.3
	50	18.4	19.5	19.7	20.0
VOC	100	2.6	2.9	2.9	3.0
	75	2.2	2.3	2.3	2.3
	50	1.8	1.9	1.9	1.9
SO_2	100	9.5	10.6	10.7	10.9
	75	7.8	8.5	8.6	8.8
	50	6.2	6.8	6.9	7.0
H_2SO_4	100	1.5	1.6	1.6	1.7
	75	1.2	1.3	1.3	1.3
	50	0.9	1.0	1.1	1.1
PM	100	18.0	18.0	18.0	18.0
	75	18.0	18.0	18.0	18.0
	50	18.0	18.0	18.0	18.0
Emissions for One GE 7FA Turbine – Distillate Oil Operation					
NO_x	100	289.6	321.0	325.5	332.1
	75	232.7	254.0	257.9	263.2
	50	181.9	199.2	201.5	204.6
CO	100	59.5	66.6	67.8	69.6
	75	50.7	56.8	57.5	58.5
	50	78.3	66.5	64.6	67.6
VOC	100	2.7	3.0	3.0	3.1
	75	2.2	2.3	2.3	2.4
	50	1.8	1.9	1.9	1.9
SO_2	100	90.3	100.2	101.6	103.6
	75	73.3	80.0	81.3	82.9
	50	57.9	63.4	64.2	65.1
H_2SO_4	100	13.8	15.3	15.6	15.9
	75	11.2	12.2	12.4	12.7
	50	8.9	9.7	9.8	10.0
PM	100	34.0	34.0	34.0	34.0
	75	34.0	34.0	34.0	34.0
	50	34.0	34.0	34.0	34.0
Pb	100	0.025	0.027	0.028	0.028
	75	0.020	0.022	0.022	0.023
	50	0.016	0.017	0.018	0.018

Table 3-2 Annual Emission Summary for the MEC Combustion Turbines

Turbine	NO_x	CO	VOC	SO_2	H_2SO_4	PM	PM_{10}	Pb
	Emissions for One Combustion Turbine (tons/year) [1]							
GE 7FA	320.3	79.6	5.2	85.8	13.1	43.5	43.5	0.02
	Emissions for All Combustion Turbines (tons/year) [1]							
3 x GE7FA	960.9	238.8	15.6	257.4	39.3	130.5	130.5	0.06

Notes:
[1] **Based on worst case hourly emission rate over the load range (50% - 100% base load), at the effective Annual Average Temperature of 50°F, and the following operation schedule:**
NG Annual Operation 2,000 hrs/year/turbine
Oil Annual Operation 1,500 hrs/year/turbine
Total Annual Operation 3,500 hrs/year/turbine

Table 3-3 Facility HAP Emission Summary

		3500 hrs Natural Gas	2000 hrs NG	1500 hrs Oil	2000 hrs NG & 1500 hrs Oil	CTGs All Cases	Fuel Heater	Facility Total
Total HAPs	tpy	5.0	2.9	3.1	6.0	6.0	0.02	6.0
Max Single HAP	tpy	2.6	1.5	1.9	1.9	2.6	2.29E-02	2.6
Max HAP Compound		Formaldehyde	Formaldehyde	Manganese	Formaldehyde	Formaldehyde	Hexane	
							Major Total HAPs	**No**
							Major Single HAP	**No**

3.2 Natural Gas Fuel Heater

Emission calculations for this unit are presented in Appendix B and summarized in Table 3-4 for criteria pollutants.

Table 3-4 Criteria Pollutant Emissions Summary for the Fuel Heater

Criteria Pollutants	Emission Rate - per Unit Hourly (Lbs/Hr)	Emission Rate - per Unit Annual (Tons/Year)
Nitrogen Oxides	1.3	2.3
Carbon Monoxide	1.2	2.1
Volatile Organic Carbon	0.78	1.37
Sulfur Oxides	0.07	0.13
Particulate	0.13	0.13

3.3 Fugitive Emissions

Breathing and working losses from the two, above-ground distillate oil storage tanks will constitute the main fugitive emissions from the MEC. The emission calculations were performed using Tanks 4.0, a U.S. EPA computer model, which considers tank characteristics, meteorological data, and annual material throughput to estimate emissions. A summary of the tanks' fugitive emissions is presented in Appendix B.

3.4 Total Project Criteria Pollutant Emission Summary

Tables 3-5 and 3-6 combine the analyses summarized on the preceding pages to establish the maximum emissions for the MEC. The annual emissions summaries reflect the maximum number of hours the turbines and fuel heater will operate. This will become a federally enforceable limitation specified in the PSD permit upon issuance.

Table 3-5 Project Hourly Emissions (lb/hr) Summary, Criteria Pollutants, MEC

Source Name	Source	NO_x	CO	VOC	SO_2	H_2SO_4	PM/PM_{10}	Pb
	Hourly Emission Rates (lb/hr)							
Combustion Turbine No. 1	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Combustion Turbine No. 2	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Combustion Turbine No. 3	GE 7FA	332.1	78.3	3.1	103.6	15.9	34.0	0.03
Fuel Heater No. 1		1.3	1.2	0.78	0.07		0.13	
Fuel Tanks				2.58				
Total		**997.6**	**236.1**	**12.7**	**310.9**		**102.1**	**0.1**
Note: This table presents the maximum emission rate over the potential operating range (50% to 100% load and 30 to 91°F) for all operating conditions (Natural Gas or Oil).								

Table 3-6 Project Annual Emissions (tons/yr) Summary, Criteria Pollutants, MEC

Source Name	Source	NO_x	CO	VOC	SO_2	H_2SO_4	PM/PM_{10}	Pb
Combustion Turbine No. 1	GE 7FA	320.3	79.6	5.2	85.8	13.1	43.5	0.02
Combustion Turbine No. 2	GE 7FA	320.3	79.6	5.2	85.8	13.1	43.5	0.02
Combustion Turbine No. 3	GE 7FA	320.3	79.6	5.2	85.8	13.1	43.5	0.02
Fuel Heater No. 1		2.3	2.1	1.37	0.13		0.23	
Fuel Tanks				2.0				
Total		**963.2**	**240.9**	**18.9**	**257.5**	**39.3**	**130.7**	**0.1**
Note: This table presents the annual potential emissions based on maximum hourly emissions over 50% to 100% load range at the effective annual average temperature of 50 °F for all operating conditions (Natural Gas or Oil)								

4.0 APPLICABLE REGULATIONS AND STANDARDS

The following air regulations have been reviewed as they may apply to the proposed facility:

- Prevention of Significant Deterioration (PSD) pre-construction review under 40 CFR Part 52;
- New Source Performance Standards (NSPS) under 40 CFR Part 60;
- National Emissions Standards for Hazardous Air Pollutants (NESHAPs) under 40 CFR Part 63;
- Acid Rain Deposition Control Program under 40 CFR Parts 72, 73, and 75;
- CAA Operating Permit Program under 40 CFR Part 70; and
- State of Florida Air Resource Management Rules under Chapter 62 of the Florida Administrative Code.

These regulations are implemented by the FDEP through the federally-approved CAA State Implementation Plan (SIP) or by U.S. EPA-delegated authority. A review of the applicability criteria for these rules and the conclusions drawn relative to the proposed facility is presented below.

4.1 Prevention of Significant Deterioration

The proposed facility is required to submit an application for a permit to construct under the Prevention of Significant Deterioration (PSD) rules codified at 40 CFR Part 52 and incorporated as a SIP-approved program into Rule 62-212.400, F.A.C. The facility would be subject to PSD review for PSD-regulated pollutants, if it is a "major" source. New sources of air emissions are considered major sources if they have the "Potential-to-Emit" (PTE) more than the 100 tons/year for "listed" source categories or 250 tons/year for all other source categories. One of the 28 source categories listed in the PSD regulations is "fossil-fuel fired steam electric plants of more than 250 million Btu per hour heat input." Gas turbines used without heat recovery, such as simple cycle peaking units, have been determined to fall outside of the 28-source category list, and thus are subject to PSD review if potential emissions of any regulated pollutant exceed 250 tons/year.

As shown in Table 3-6, air emissions from the MEC will exceed the 250 ton per year threshold for one or more criteria pollutants. As such, PSD review is required for each pollutant emitted in excess of the Significant Emission Rates listed in Table 62-212.400-2 F.A.C. and shown in Table 4-1.

Table 4-1 Project PTE (TPY) Criteria Pollutant Emissions Summary, Midway Energy Center

Source Name	NO_X	CO	VOC	SO_2	PM/PM_{10}	H_2SO_4	Pb
Combustion Turbine No. 1	320.3	79.6	5.2	85.8	43.5	13.1	0.02
Combustion Turbine No. 2	320.3	79.6	5.2	85.8	43.5	13.1	0.02
Combustion Turbine No. 3	320.3	79.6	5.2	85.8	43.5	13.1	0.02
Natural Gas Heater	2.3	2.1	1.4	0.13	0.23		
Distillate Oil Storage			2.0				
Total (Tons/year)	**963.2**	**240.9**	**18.9**	**257.5**	**130.7**	**39.3**	**0.1**
PSD Major Source Threshold	**250**	**250**	**250**	**250**	**250**	**250**	**250**
PSD Significant Threshold	**40**	**100**	**40**	**40**	**25/15**	**7**	**0.6**

The following requirements are encompassed by PSD review.

- Compliance with any applicable emission limitation under the State Implementation Plan (SIP);
- Compliance with any applicable NSPS or NESHAPS;
- Application of Best Available Control Technology (BACT), as defined by the PSD rules, to emissions of NO_x, CO, SO_2, and PM/PM_{10} from all significant sources at the facility;
- A demonstration that the facility's potential emissions, and any emissions of regulated pollutants resulting from directly related growth of a residential, commercial or industrial nature, will neither cause nor contribute to a violation of the NAAQS or allowable PSD increments;
- An analysis of the impacts on local soils, vegetation and visibility resulting from emissions from the facility and emissions from directly related growth of a residential, commercial, or industrial nature;
- An evaluation of impacts on Visibility and Air Quality Related Values (AQRVs) in PSD Class I areas (if applicable); and
- At the discretion of FDEP, pre-construction and/or post-construction air quality monitoring for NO_x, CO, SO_2, and PM/PM_{10}.

Potentially applicable SIP limitations, NSPS and NESHAPs requirements are discussed below. A detailed BACT analysis is presented in Section 5. Contributions to the NAAQS and PSD increments are discussed in Section 6. Impacts on local soils, vegetation, and visibility are addressed in Section 7.

4.2 NSPS

The NSPS regulation that applies to combustion turbines is Subpart GG. This standard is applicable to stationary gas turbine units that have a heat input of greater than 10 MMBtu/hr. Under Subpart GG, units with a heat input at peak load greater than 100 MMBtu/hr and which supply more than one third of their electric generating capacity to a utility distribution system shall not emit NO_x in excess of:

$$STD = 0.0075(14.4/Y) + F$$

Where:

STD is the allowable NO_x emission, percent volume (corrected to 15 percent oxygen dry basis)

Y is rated heat rate at peak load, kilojoules/watt hour

F is NO_x emission allowance for fuel bound nitrogen, percent volume (for nitrogen content greater than 0.25 percent weight, F is 0.005 percent volume)

Applying the heat rate to the proposed General Electric 7FA turbine results in an applicable NSPS for NO_x emissions of approximately 110 ppmv on a dry basis, corrected to 15 percent oxygen, when firing natural gas. For distillate oil firing, the applicable NSPS limit is 102 ppm @ 15% oxygen. Both of these emission limits are well above the levels proposed as BACT (see Section 5).

Subpart GG also regulates the discharge of SO_2 by requiring compliance with one of the following two options:

- Limit SO_2 emissions to 0.015 percent or less by volume at 15 percent O_2 on a dry basis, or
- Limit the sulfur content of the fuel to 0.8 percent by weight or less.

The proposed project will readily meet the NSPS for SO_2 as both the proposed natural gas (2 grains/100 SCF) and distillate oil (<0.05 wt%) fuels will contain less than 0.8 percent sulfur content by weight.

Subpart Kb applies to each storage vessel, with some specified exceptions, with a capacity greater than or equal to 40 m^3 that is used to store volatile organic liquids for which construction commenced after July 23, 1984. Subpart Kb establishes storage vessel control equipment specifications, testing and associated procedures, and reporting and record keeping requirements. For this project, the distillate oil storage vessels will be subject to Subpart Kb based upon their maximum storage capacity. Due to the low vapor pressure of No. 2 distillate oil, these tanks will only be required to maintain records of the dimensions and maximum capacity of the tanks. No control requirements will apply.

4.3 NESHAPS

There is currently no NESHAPs for stationary gas turbines, although this is a source category scheduled for a determination of Maximum Achievable Control Technology (MACT) under 40 CFR Part 63. However, 40 CFR Part 63, Subpart B govems the construction or reconstruction of major sources of Hazardous Air Pollutants (HAPs) for which a NESHAP has not been promulgated. The rule requires new major sources of HAPs to install MACT for HAPs. MACT must be determined as a condition of pre-construction approval. A major source of HAPs is any stationary source that has the potential to emit 10 tons/year or more of a single HAP or 25 tons/year of combined HAPs.

Table 4-2 summarizes the project PTE for non-criteria pollutants. The project is not a major HAP source, and, therefore, 40 CFR Part 63 Subpart B does not apply.

Table 4-2 Project PTE Non-Criteria Pollutant Emissions Summary

Emission Source	HAP Emission Rate		Maximum HAP Emission Rate	
	Lbs/Hr	tons/year	Lbs/Hr	tons/year
Combustion Turbines[a]	4.7	6.0	1.5	2.6
Fuel Heater[b]	2.5×10^{-2}	0.04	2.3×10^{-2}	0.04
Total	4.7	6.0	1.5	2.6

(a) Formaldehyde is the single HAP, which has the greatest contribution to the Total HAP Potential to Emit from the combustion turbines.

(b) Hexane is the single HAP which has the greatest contribution to the Total HAP Potential to Emit from the fuel heater.

4.4 Acid Rain

The proposed facility meets the definition of "utility unit" and will be an affected Phase II unit under the Acid Rain Deposition Control Program pursuant to Title IV of the Clean Air Act. The proposed facility will have to obtain a Title IV permit before commencing operation. The Title IV permit will require that the facility hold calendar-year allowances for each ton of SO_2 that is emitted and conduct emissions monitoring for SO_2 and NO_x pursuant to the requirements in 40 CFR Parts 72, 73, and 75.

4.5 CAA Operating Permit Program

FDEP administers the CAA Operating Permit Program under Rule 62-213 which has been approved by EPA under 40 CFR Part 70. A new major source must submit a Title V operating permit application to FDEP within 180 days after commencing operation. The Title V application will incorporate applicable emission limitations, monitoring, record keeping and reporting requirements from the PSD construction permit.

4.6 State SIP Rules

In addition to the above regulations, the proposed facility is also subject to the Florida Air Pollution Control Regulations codified in Chapters 62-204 through 62-297 of the Florida Administrative Code (F.A.C.). The F.A.C. rules that are potentially applicable to the proposed project are as follows:

- General Pollutant Emission Limiting Standards

  Rule 62-296.320 limits visible emissions from any activity not specifically addressed by another Florida Regulation in Chapter 62-296. The general visible emission standard for stacks limits opacity to 20%. Compliance with the visible emission standard must be done in accordance with U.S. EPA Method 9. A companion rule limits visible emissions from fugitive sources by requiring sources to take reasonable precautions to prevent such emissions. Fugitive emissions may occur during construction of the facility. Wet suppression or similar techniques will be used to control emissions as necessary during construction activities

- General Construction Permitting Requirements

  Rule 62-210.310 requires that an air construction permit be obtained prior to commencing construction. The requirements for construction permits and approvals are contained in Rules 62-4.030, 62-4.050, 62-4.210, and 62-210.300(1). This document includes the general information required by the FDEP for a construction permit application.

- Stack Height Policy

  Rule 62-210.550 specifies the stack height requirements and permissible dispersion techniques for permitting air emission sources. The facility will comply with the provisions of this regulation as presented in the air quality impact assessment (Section 6).

- Excess Emissions

  Rule 62-210.700 provides allowances for excess emissions for emission units that may occur during periods of startup, shutdown, malfunction, and load changes (non steady-state operations). Excess emissions from the combustion turbines are expected to occur during startup and shutdowns. The facility will apply best operational practices to minimize the duration of excess emissions.

- Annual Emissions Reporting

  Rule 62-210.370 requires Title V sources to submit an annual operating report that provides emissions information for the previous calendar year. Midway Development Company, LLC will submit to the FDEP annual emissions reports by March 1 of the following year.

5.0 CONTROL TECHNOLOGY EVALUATION

5.1 Introduction

In accordance with PSD requirements, FDEP requires the application of Best Available Control Technology (BACT) for the control of each regulated pollutant emitted in significant quantities from a new major stationary source located in an attainment area for that pollutant. The proposed Midway Energy Center's combustion turbines must demonstrate the application of BACT for oxides of nitrogen (NO_X), carbon monoxide (CO), fine particulate (PM_{10}), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4).

5.1.1 Top-Down BACT Approach

The BACT requirements are intended to ensure that a proposed facility or major modification will incorporate air pollution control systems that reflect the latest demonstrated practical techniques for each particular emission unit, and will not result in the exceedance of a National Ambient Air Quality Standard (NAAQS), PSD Increment, or other standards imposed at the state level. The BACT evaluation requires the documentation of performance levels achievable for each air pollution control technology applicable to the Midway Energy Center.

EPA and FDEP recommend a "top-down" approach when evaluating available air pollution control technologies. This approach to BACT involves determining the most stringent control technique available, known as the Lowest Achievable Emission Rate (LAER) for a similar or identical emission source. If it can be shown that the LAER is technically, environmentally, or economically impractical on a case-by-case basis for the proposed emission source, then the next most stringent level of control is similarly evaluated. This process continues until a control technology and associated emission level is determined that cannot be eliminated by any technical, environmental, or economic objections. The top-down BACT evaluation process is described in U.S. EPA's draft document "New Source Review Workshop Manual (U.S. EPA, October 1990). The five steps involved in a top-down BACT evaluation are:

- Identify options with practical potential for control of the regulated pollutant under evaluation;
- Eliminate technically infeasible or unavailable technology options;
- Rank the remaining control technologies by control effectiveness;
- Evaluate the most effective controls and document the results; if the top option is not selected as BACT, evaluate the next most effective control option; and

- Select BACT, which will be the most effective practical option not rejected based on prohibitive energy, environmental, or economic impacts.

ENSR employed the "top-down" approach in evaluating available pollution controls for the Midway Energy Center.

5.1.2 Cost Determination Methodology

Economic analyses of certain BACT alternatives were performed to compare capital and annual control costs in terms of cost-effectiveness (i.e., dollars per ton of pollutant removed). Capital costs include the initial cost of components intrinsic to the complete control system. High-temperature SCR, for example, would include catalyst modules, transition piece, support frame, ammonia storage tanks, ammonia dilution air and injection system, piping, flue gas attemperation system, provisions for catalyst cleaning and removal, instrumentation, and installation costs. Annual operating costs consist of the financial efficiency losses, parasitic loads, and revenue loss from operation of the control system and include overhead, maintenance, labor, raw materials, and utilities.

5.1.3 Capital Costs

The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation costs. This technique is a modified version of the "Lang Method," whereby installation costs are expressed as a function of known equipment costs. This method is consistent with the latest U.S. EPA guidance manual (OAQPS Control Cost Manual) on estimating control technology costs (U.S. EPA, January 1996). The estimation factors used to calculate total capital costs are shown in Table 5-1.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for continuous operation of the device. These may include such items as reagent storage tanks, supply piping, turbine outlet transition piece, catalyst removal crane, spare parts and catalyst, and air dilution system. Auxiliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage based on the average requirements of typical systems and their auxiliary equipment (U.S. EPA, January 1996). In this BACT evaluation, basic equipment costs were obtained from data provided by qualified vendors (see Appendix C). Instrumentation, which is usually not included in the basic equipment cost, is estimated at 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor including site preparation, foundations, structural steel, insulation erection, piping, electrical, painting, and enclosure.

Table 5-1 Capital Cost Estimation Factors

Item	Basis
Direct Costs	
Purchased Equipment Cost	
Equipment cost + auxiliaries[1]	A
Instrumentation	0.10 x A
Sales taxes	0.06 x A
Freight	0.05 x A
Total Purchased equipment cost, (PEC)	B = 1.21 x A
Direct installation costs	
Foundations and supports	0.08 x B
Handling and erection	0.14 x B
Electrical	0.04 x B
Piping	0.02 x B
Insulation for ductwork	0.01 x B
Painting	0.01 x B
Total direct installation cost	0.30 x B
Site Preparation, SP	As Required
Buildings, Bldg	As Required,
Total Direct Cost, DC	1.30B + SP + Bldg.
Indirect Costs (installation)	
Engineering	0.10 x B
Construction and field expenses	0.05 x B
Contractor fees	0.10 x B
Start-up	0.02 x B
Performance test	0.01 x B
Contingencies	Variable
Other[2]	As Required
Interest during construction[3]	DC x i x n
Total Indirect Cost, IC	0.28B + Interest + Contingencies
Total Capital Investment (TCI) = DC + IC	**1.58B+ SP + Bldg. + Interest + Contingencies**

[1]Auxilliaries include ammonia tank, transition piece, crane, spare catalyst, dilution air system, etc.

[2]Emergency Response Plan (ER), Spill Prevention Countermeasure and Control (SPCC), Risk Management Plan (RMP), etc.

[3]Simple Interest During Construction, i = interest rate; n = interest period

Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, contingencies, and additional permits and licensing costs.

Direct installation costs are expressed as a function of the purchased equipment cost, based on average installation requirements of typical systems. Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment startup and performance testing, contingencies, working capital, and interest during construction.

5.1.3.1 Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include electricity losses, labor, maintenance, replacement parts, raw materials, and utilities. Indirect operating costs include overhead, taxes, insurance, general administration, contingencies, and capital charges. Annualized cost factors used to estimate total annualized cost are listed in Table 5-2, and are consistent with the EPA guidance on estimating control technology costs (U.S. EPA, January 1996).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs are calculated as 3 percent of total direct cost (TDC). Replacement part costs, such as the cost to replace aged or failed catalyst, have been included where appropriate. Reagent and utility costs are based upon estimated annual consumption and the unit costs are summarized in Table 5-2. The presence of a catalyst bed would increase turbine back pressure resulting in heat rate (efficiency) losses to the system. This is reflected in the economic analysis as the value of lost power output and is based on turbine vendor estimates. Based on the experience of other facilities contacted, the catalyst for a catalytic oxidation or reduction technology is assumed in this analysis to require replacement every 3 years due to failure or aging. The cost of replacement catalyst was provided by catalyst vendors which was then annualized over 3 years.

With the exception of overhead and contingency, indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where "i" is the annual interest rate and "n" is the equipment economic life (years). An emission control system's economic life is typically 10 to 20 years (U.S. EPA, January 1996). In this analysis, a 10-year equipment economic life (typical length of financing) was used. The average interest rate is assumed to be 7 percent (U.S. EPA, January 1996). CRF is therefore calculated to be 0.142.

Table 5-2 Annualized Cost Factors

Item	Cost Factor	Unit Cost
DIRECT ANNUAL COSTS, DC		
Electricity		
Heat rate loss due to pressure drop	0.1% output loss for every inch of delta P	$0.10/kW-hr
Power lost due to extended startups	Extended startups due to catalyst bed	$0.10/kW-hr
Dilution air fan electricity	Dilution air to prevent catalyst deterioration	$0.10/kW-hr
Operating labor		
SCR Labor Req.	0.5 hr/shift	$30.00/hr
Supervisor	15% Operating Labor	NA
Ammonia Delivery Requirement	24 hr/yr (3 deliveries per year)	
Ammonia Recordkeeping and Reporting	40 hr/yr (1 week of reporting)	
Catalyst Cleaning	80 hr/yr (2 workers x 40 hr/yr)	
Maintenance		
Catalyst Replacement Labor	8 workers, 40 hr, every 3 years	$30.00/hr
Catalyst System Maintenance Labor Req.	0.5 hr/shift	$30.00/hr
Ammonia System Maintenance Labor Req.	1 hr/day, 365 day/yr	$30.00/hr
Material	100% Maintenance Labor	NA
Ammonia	Ammonia	$315 per ton
Process Air	350 scf/lb NH_3	$0.20 per thousand scf
Catalyst	100% replaced/3 years plus disposal	
INDIRECT ANNUAL COSTS, IC		
Overhead	60% labor + materials	
Administrative Charges	2% TCI	
Property Taxes	1% TCI	
Insurance	1% TCI	
Capital Recovery	CRF x TCI	
Contingency for new technology	NA	0-20% DC
Total Annual Cost (TAC) ($)		Sum of Annual Costs
Total Pollutant Controlled (ton/yr)		As Calculated
COST EFFECTIVENESS ($/ton)		**TAC/tpy controlled**

5.1.3.2 Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the technology and its annual pollutant emission reduction. Cost-effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical tons of pollutant that would be removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on comparing the uncontrolled emission rate with the achievable emission rate based on information contained in issued permits, EPA literature and vendors of the control equipment.

5.2 Previous BACT/LAER Determinations for Simple-Cycle Combustion Turbines

The proposed Midway Energy Center is a “Simple-Cycle” electrical peaking facility. A Simple-Cycle peaking project is fundamentally different than the more common “Combined-Cycle” base load systems that represent the majority of listings in EPA’s RACT/BACT/LAER Clearinghouse. The differences in these two types of power generation technology are reviewed in Sections 5.2.1 and 5.2.2.

In a deregulated market for electricity, new generation capacity will be built only when there is a sufficient customer demand for that capacity. The electric output of any new capacity must be sold (and must therefore be priced competitively with existing capacity) in order to earn a Return On Investment (ROI) commensurate with the financial risk of building the powerplant. A market need exists in Florida for peak load power and, therefore, the Midway Energy Center is being developed to serve that specific peak power market.

5.2.1 Base Load Power (Combined-Cycle)

Regional power demand is variable from night to day, from hot summer days (which reflect air-conditioning loads) to cold winter days, from workdays to weekends, etc. However,, there is a certain constant level of electrical demand that is always present, referred to as “base load”. The nature of generation capacity built to provide base load power is that it is designed to maximize annual operation at a constant or “base” load at the lowest operating cost possible. Since fuel cost is the single biggest component of the cost to produce power, competitive base load generators must be designed to operate at the highest possible fuel efficiency and to produce their rated output continuously at maximum availability. The Combined-Cycle plant meets these criteria.

A rotating combustion turbine, driving a generator via a connecting shaft represents a thermodynamic cycle known as the Brayton Cycle; this arrangement is also referred to as “Simple-Cycle”. In a Simple-Cycle turbine, air and products of combustion exiting the turbine are exhausted to the atmosphere at temperatures of about 1,100°F, which represents a substantial energy loss.

A boiler that produces steam which is then used to generate electricity in a steam turbine/generator is referred to as the Rankine Cycle. In this thermodynamic cycle, energy lost as waste heat from a surface condenser is typically rejected to cooling towers or a large body of cooling water. Traditional central utility powerplants are of this design. Condensation of steam with cooling water also represents a substantial energy loss.

Each of these cycles is significantly limited in achievable "heat rate" (the amount of electricity that can be generated per Btu of fuel input) because in each case substantial amounts of heat energy are wasted. When a Brayton Cycle turbine is connected in series with a Rankine Cycle waste heat boiler, a much lower heat rate (higher thermal efficiency) can be achieved. This is referred to as "Combined-Cycle". While a Combined-Cycle powerplant exhibits much higher initial capital cost, these costs can be quickly recovered in greater fuel efficiency in a base load plant which operates around the clock at near full capacity. The Combined-Cycle powerplant therefore, by definition incorporates a waste heat boiler or Heat Recovery Steam Generator (HRSG) and steam turbine generator. The HRSG recovers waste heat exiting the turbine at about 1,100°F and exhausts at about 220°F. With an HRSG as a component of the above-mentioned combined cycle, a temperature "window" exists which has allowed catalytic pollution control technology to be widely applied to new Combined-Cycle powerplants. This post combustion control technology is responsible for the very low (i.e. 2.5 – 3.5 ppm) NO_x emission rates reported for recent Combined-Cycle units in EPA's RACT/BACT/LAER Clearinghouse.

5.2.2 Peaking Power (Simple-Cycle)

Once base load demand is satisfied, a need still exists to supply additional power at certain times when base load requirements are exceeded by the short term peak power demand. Average peak power prices tend to be higher than for base load power. However, peaking units operate substantially fewer hours per year than base load units. The economics of providing peak power favor lower initial capital cost (there are fewer operating hours per year in which to earn back the capital investment) and are less sensitive to optimization of heat rate. Most importantly, peak power must be able to come on-and off-line very quickly and, in some cases is designed to "follow" electrical demand.

Simple-Cycle is the only combustion turbine configuration that meets this requirement. For example, a common application of combustion turbine engines that do not employ an HRSG is for aircraft applications. Helicopters and turbo-prop commuter aircraft utilize combustion turbine engines that drive a mechanical propeller shaft. These engines are routinely shut down during boarding, started up for taxiing and accelerated to full output during takeoff, all within a matter of minutes. Combined-Cycle units, on the other hand require a cold start-up schedule, measured in hours, to be brought from ambient temperature to full load. This is because the heat transfer surfaces and catalyst beds within the HRSG are sensitive to "thermal shock". Ceramics and steel that are heated too quickly are subjected to uneven thermal expansion and will warp, crack and/or fail if not allowed sufficient time to be brought to temperature more gradually. Start up schedules that are designed to protect back end equipment typically involve several steps of "ramping" and "soaking." This soaking time is required to protect the back-end equipment from failure due to thermal stress limits the feasibility of HRSG's and catalysts for use in quick response peaking applications. On any given day, the demand for peak power may only last three to four hours. By the time a Combined-Cycle unit has been warmed up to full operating load, the market demand to produce the peak power may be over.

5.2.3 BACT Determinations for Simple-Cycle Combustion Turbines

When reviewing emission levels that have been permitted as BACT or LAER in EPA's database, it is important to distinguish between Simple-Cycle and Combined-Cycle source categories, although the Clearinghouse listings are not always clearly categorized. It should also be noted that natural gas pipeline compressor engines are mechanical compressor drive applications; while they do not employ HRSG's, these sources are much smaller units (2-5 MW equivalent) and do not cycle on and off to meet demand as quickly or as frequently as power generation peaking turbines do. Compressor station turbines are not representative of a large scale peaking powerplant application.

A list of previous BACT/LAER determinations for all types of combustion turbines is presented in Appendix C. These tables are compiled from EPA's RACT/BACT/LAER Clearinghouse and from ENSR's database of combustion turbine projects. The RACT/BACT/LAER Clearinghouse keeps a listing of RACT/BACT/LAER determinations by governmental agencies for many types of air emission sources, and is available in hard copy or through a computerized database. While the RACT/BACT/LAER Clearinghouse covers information from the past 10 to 12 years, only the more recent decisions (1993-present) have been included here.

It should be noted that all listings in California represent LAER, even though they are often listed as BACT (BACT and LAER in California are identical). LAER is a much more stringent requirement than BACT, and involves application of control technology regardless of cost. This is not the case for the proposed Midway Energy Center peaking project. ENSR also reviewed the California Air Pollution Control Officers Association (CAPCOA) on-line BACT Clearinghouse and found the only LAER decisions listed after 1993 to be for the same facilities. ENSR also called regulators in Indiana, California and several other states to determine levels of control which are being proposed or required of the most recent projects. Finally, ENSR contacted the turbine and catalyst manufacturers. Our search identified several Simple Cycle projects not listed in EPA's BACT/RACT/LAER Clearinghouse which have been permitted recently in California with lower emission limits and which employ add-on control technology.

5.2.4 Combustion Turbine Fuel Use

As part of its application, the Midway Energy Facility is requesting increased flexibility regarding the ability to burn 1,500 hours per year of oil. While the intention is to burn natural gas at every opportunity, near term constraints on the Florida Gas Transmission ("FGT") pipeline may impede the ability to burn natural gas during periods of peak demand often associated with the summer season. In general, the

FGT natural gas transmission line flows near its maximum pipeline capacity of 1.5 Bcf/day during the summer season. In order to accommodate the demand for incremental generation within the state of Florida, FGT plans to expand its pipeline capacity by approximately 600,000 MMbtu/day before the summer of 2002. Additionally, FGT is in active discussions with potential shippers to perform another expansion of its pipeline in 2003. The addition of this capacity should reduce periods of pipeline constraint and will result in an increased availability of natural gas to the proposed site. The request for greater oil burning flexibility is necessitated by near term FGT capacity constraints and is not due to deficient gas supplies received by FGT. Moreover, operational guidelines dictate that natural gas be the primary fuel source and oil will be used only to the extent transmission capacity constraints on FGT preclude the delivery of natural gas to the site

As the proposed facility is intended to provide peak power which will typically occur during periods when natural gas demand will be high, the ability to operate using distillate oil as an altemative fuel is necessary to provide system reliability. As the facility is being proposed as a duel fuel facility the control technology analysis has been performed assuming the maximum amount of oil consumption, when determining potential emissions.

5.3 BACT for Nitrogen Oxides (NO_x)

5.3.1 Formation

NO_x is primarily formed in combustion processes in two ways: 1) the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Although natural gas contains free nitrogen, it does not contain fuel bound nitrogen (EPA 1996); therefore, NO_x emissions from combustion turbines when burning natural gas originate as thermal NO_x. The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. Liquid fuels such as No. 2 distillate contain significant levels of fuel bound nitrogen. The combustion of liquid fuels results in inherently higher emissions of NO_x due to the combination of both thermal NO_x and fuel NO_x which forms when fuel nitrogen is exposed to high flame temperatures in the presence of free oxygen.

5.3.2 Front – End Control

"Front-end" NO_x control techniques are aimed at controlling one or more of these variables. The primary front-end combustion controls for gas turbines include water or steam injection and dry low NO_x combustors. The addition of an inert diluent such as water or steam into the high temperature region of the flame controls NO_x formation by quenching peak flame temperature, which reduces emissions of both thermal and fuel NO_x. This technique can be operationally very hard on the turbine and combustors due to vibration and flame instability. Recent advances in the state-of-the-art have resulted in dry low NO_x combustors for gas firing that limit peak flame temperature and excess oxygen with lean, pre-mix flames, that can achieve equal or better NO_x control without the addition of water or steam. Catalytic combustion is an emerging front-end technology for gas-only fired turbines using an oxidation catalyst within the combustor to produce a lower temperature flame and hence, low NO_x. Catalytic combustion is potentially capable of reducing natural gas-fired turbine NO_x emissions to 2-5 ppmv, but is not applicable to oil-fired or dual fuel applications. Catalytica, Inc. was the first company to commercially develop catalytic combustion controls for certain (mostly smaller) turbine engines and markets them under the name XONON™. Catalytic combustion technology is not yet commercially available for 170 MW F-Class turbines, and is not a technically feasible technology for dual fuel operation. Therefore, XONON™ does not represent an available control option for the Midway Energy Facility.

5.3.3 Back – End Control

Other control methods, known as "back-end" controls, remove NO_x from the exhaust gas stream once NO_x has been formed. Selective Catalytic Reduction (SCR) using ammonia as a reagent represents the state-of-the-art for back end gas turbine NO_x removal from base load, combined cycle turbines. Conventional SCR is not applicable to simple cycle turbines due to materials temperature limitations which preclude its application in high temperature simple cycle turbine exhaust. A high temperature SCR technology has recently been introduced for potential application to simple-cycle turbines but with limited success to date. In particular, high temperature SCR has been applied at a few small peaking turbines in California.

Selective catalytic reduction (SCR) is a process which involves post-combustion removal of NO_x from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water by the following reactions (Cho, 1994):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad (1)$$

$$6NO + 4NH_3 \rightarrow 5N_2 + 6H_2O \quad (2)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad (3)$$

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \quad (4)$$

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O \quad (5)$$

The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling", design of the NH_3 injection system, and high NH_3 slip. There are only four U.S. installations of this technology on simple cycle peaking turbines (Booth, 1999), and none of these has a long-term history of success. Three of these applications are on relatively small natural gas-only peaking turbines that have limited hours of operation to date. While these units have reported some initial problems, U.S. EPA has indicated that they consider high temperature SCR to be "demonstrated in practice" for natural gas fired peaking turbines.

One of the high temperature SCR installations is the Cambalache Electric Generating Facility, located in Puerto Rico. This project consists of three (3) ABB GT 11N1 combustion turbines operated in simple cycle mode, using distillate oil. The original permit issued for these turbines required the use of SCR to achieve NO_x emissions of 10 ppm, with a limit of 10 ppm on ammonia emissions. This plant has been operating since 1997 with very poor results for the operation of the SCR system. This project has not been able to operate for any extended period of time while staying within the NO_x and NH_3 limits and has been issued a Notice of Violation by EPA for exceedances of both NO_x and NH_3. Several attempts have been made to regenerate, or clean the catalyst, with no significant improvement in the performance of the system.

As a result of this experience, Englehard is no longer offering this technology for oil-fired turbine applications. The Midway Energy Center Facility is a dual fuel peaking project that must have the flexibility to burn liquid fuel as backup to natural gas. High temperature SCR is not technically feasible for oil firing, and has not been demonstrated in practice on dual fuel peaking turbines. In addition, this technology would not be cost effective, even if the turbines were natural gas only. As shown in Appendix C, high temperature SCR controlling NO_x emissions to the LAER levels of 5 ppmvd @ 15% O_2 while firing natural gas and 10 ppmvd @ 15% O_2 while firing distillate oil would cost over $20,000/ton of NO_x removed.

On August 4, 2000 US EPA issued draft combustion turbine BACT guidance for public review (Appendix C). While this draft document is only being circulated for comment and does not represent official EPA policy, it does contain useful information relative to the application of SCR to GE's 9 ppm DLN generation turbines. Note that the discussion by EPA identifies several negative collateral environmental impacts associated with application of SCR to 9 ppm base load, combined cycle turbines. These negative impacts are exacerbated for simple cycle peaking applications, as discussed below:

Peaking turbines start and stop quickly, and may only operate a few hours at a time. Until the SCR catalyst reaches temperature, ammonia (NH_3) may not be introduced (resulting in less relative NO_x control), or if it is introduced will result in elevated NH_3 slip. Since a significant portion of a peaking turbines operation is spent warming up, following load (transient operation) and shutting down, high temperature SCR would control less NO_x and emit more slip when dispatched than a base load turbine would.

To reduce NO_x from 9-12 ppm to 5 ppm (the LAER for gas-only peaking turbines in California) on units that will operate less than 3,500 hours per year will result in much lower NO_x reduction benefits than for EPA's analysis of combined cycle units. It should be noted that 3,500 hours represents an upper limit on operation for permitting, but in actual operation peaking units may in fact be normally dispatched less than 1,500 hours per year.

Peaking turbines may be thought of as similar to emergency generators. When they are called upon to operate, it is to fill a temporary shortfall in generation capability. SCR systems rob electrical output (due to backpressure) precisely when that output is most needed (peak demand).

High temperature SCR is therefore, not technically feasible, would exhibit overriding negative collateral environmental impacts, and in any event would not be cost effective for application to the dual fuel Midway Energy Facility.

An emerging technology called $SCONO_X$™, which also uses a back-end catalyst but operates without ammonia, has shown promise during initial trials on a 23 MW turbine installation in California, and a 5 MW turbine in Massachusetts. $SCONO_X$™ is an emerging technology that offers the promise of reducing NO_x concentrations to approximately 2-3.5 ppmv for smaller turbine applications. Despite this promise, $SCONO_X$™ is still very new and only operates effectively over a narrow 300°F to 500°F temperature range. According to the ABB Alstom internet website, ($SCONO_X$™ is marketed for applications greater than 100MW by Alstom). $SCONO_X$™ is not available for application to simple cycle combustion turbines. The planned Midway Energy Facility turbines will have exhaust temperatures of 1100 to 1200°F therefore, $SCONO_X$™ is not a technically feasible control option for the proposed Midway Energy Facility.

Two other back-end catalytic reduction technologies, Selective Non-Catalytic Reduction (SNCR) and Nonselective Catalytic Reduction (NSCR), have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1300 to 2100°F, with an optimum operating temperature zone between 1600 and 1900°F (Fuel Tech, 1991). Simple-cycle combustion turbines have exhaust temperatures of approximately 1100°F. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the Midway Energy Facility turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible and inappropriate for the Midway Energy Facility turbines.

The technologies that may represent effective controls for the proposed dual fuel peaking turbines are ranked and evaluated in the following sections. It should be stressed that levels of control being evaluated as BACT must be applicable to a dual fuel peaking power plant that will employ simple-cycle turbines for limited annual hours of operation.

5.3.4 Gas Turbines - Ranking of Available Control Techniques

Emission levels and control technologies for all types of combustion turbines have been identified and ranked for application to simple cycle dual fuel peaking turbines (see Table 5-3). Dry low NO_x controls (as described in EPA's draft turbine policy) represent the most stringent control technology for the planned turbine installation. Environmental, technical, and economic analyses of various DLN emissions levels are reviewed in the remaining BACT evaluation sections.

Table 5-3 Ranking of NO_x Control Technologies for a Dual Fuel Simple-Cycle Peaking Turbine

Control Technology	Typical Control Efficiency Range (% Removal)	Typical Emission Level[a] (ppmv)	Technically Feasible on Dual Fuel Simple-Cycle Gas Turbine
SCONOx™	90-95	2-3.5	No
XONON™ flameless combustion	80-90	2-5	No
NSCR	30-70	9-25	No
SNCR	30-70	9-25	No
Conventional (low temperature) SCR plus water injection or SCR plus low-NO_x combustor	50-95	2-6	No
High Temperature SCR plus water/steam injection or advanced low-NO_x combustor	50-95	5-12	No
Dry low-NO_x Combustor	30-70	9-25 (gas)	Yes
Water/steam injection Combustor	30-70	25-42 (oil)	Yes
[a] **Values represent long-term emission rates.**			

A search of the U.S. EPA RACT/BACT/LAER Clearinghouse was completed to assist in the identification of potential control alternatives. The RACT/BACT/LAER Clearinghouse has become out of date due to the rapid pace of power projects being permitted due to deregulation of the power generation industry.

In order to determine the specific NO_x emission levels being permitted for recent peaking turbine projects, ENSR also reviewed an informal list of recent projects obtained from US EPA. The simple cycle turbines subject to BACT in EPA's list are provided in Table 5-4. It can be seen from this list that many simple cycle turbines are being permitted with dry low NO_x combustors in the range of 9–15 ppm. These emission levels are discussed in the following sections as candidates for BACT from the Midway Energy Center.

Table 5-4 US EPA National Simple Cycle PSD Turbine Projects

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 4	AL	Applic. Under review	South Eastern Energy Corp.	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/SC R if CC		For NOx and CO: SC w/GE or SC w/SW501F or CC (either)
REGION 4	AL	applic. under review	Tenaska Alabama II Generating Station	3	3	GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 720 FO	15/42 ppm (SC); 4/42 ppm (CC)	DLN/WI ; SCR/WI		
REGION 4	FL	10-99	Polk Power (TECO)	2		GE 7 FA (165 MW)	NG; FO	SC	5,130; 750 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	11-99	Oleander Power	5		GE 7FA (190 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	10-99	Hardee Power Partners (TECO)	1		GE 7EA (75 MW)	NG; FO	SC	8,760; 876 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	12-99	Reliant Energy Osceola	3		GE 7FA (170 MW)	NG; FO	SC	3,000; 2,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	12-99	Florida Power Corp., Intercession City	3		GE 7EA (87 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	10-99	Jacksonville Electric Authority - Brandy Branch	3		GE 7FA (170 MW)	NG; FO	SC	4,000; 800 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	1-00	IPS Avon Park - Shady Hills	3		GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	draft permit	Palmetto Power	3		SW 501F (180 MW)	NG	SC	3,750	15 ppm	DLN		
REGION 4	FL	applic. under review	Granite Power Partners	3		(180 MW)	NG; FO	SC	3,000; 500 FO	10.5/15/15/ 25 ppm NG; 42 ppm FO	DLN		4 vendor options:.GE 7FA/SW 501F/SW 501D5A/ABB GT-24
REGION 4	FL	draft permit	IPS Avon Park Corp. - DeSoto Power Project	3		GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	FL	applic. under review	Florida Power & Light - Martin Power Plant	2		GE 7FA (170 MW)	NG; FO	SC	3,390; 500 FO	10.5 ppm NG (15 ppm HPM); 42 ppm FO	DLN; WI		HPM = High Power Mode (power augmentation)
REGION 4	GA	12-98	Tenaska Georgia Partners, L.P.	6		GE 7FA (160 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	GA	6-99	West Georgia Generating; Thomaston	4		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		
REGION 4	GA	10-99	Heard County Power	3		SW 501FD (170 MW)	NG	SC	4,000	15 ppm	DLN		
REGION 4	GA	8-99	Georgia Power, Jackson County	16		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		
REGION 4	KY	applic. under review	Duke Energy - Marshall Co.	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr	

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 4	FL	7-10-98	City of Lakeland, McIntosh Power Plant	1		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		Power Augmentation
REGION 4	MS	applic. under review	Duke Energy Southaven	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI		
REGION 4	MS	applic. under review	Warren Power LLC	4		GE 7EA (80 MW)	NG	SC	2,000	9 ppm	DLN		
REGION 4	NC	11-99	Carolina Power & Light, Richmond Co.	7		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		
REGION 4	NC	11-99	Carolina Power & Light, Rowan Co.	5		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		
REGION 4	NC	6-99	Rockingham Power (Dynegy)	5		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		
REGION 4	NC	applic. under review	Butler-Warner Generation Plant	2		GE 7FA (170 MW)	NG; FO	SC & CC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	SC	draft permit	Santee Cooper, Rainey Generating Station	4		GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	SC	12-99	Broad River Energy (SkyGen)	3		GE 7FA (171 MW)	NG, FO	SC	3,000; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
REGION 4	TN	7-99	TVA, Johnsonville Fossil Plant	4		GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI ?		10% NG base mode, 10% NG peaking, 10% FO base
REGION 4	TN	7-99	TVA, Gallatin Fossil Plant	4		GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI ?		10% NG base mode, 10% NG peaking, 10% FO base
REGION 4	TN	applic. under review	TVA, Lagoon Creek Plant	16		GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI ?	30;15 day	10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
REGION 5	IL	Dec-98	Peoples Gas, McDonell Energy	4		170 MW	NG, ethane	SC	1,500	15 ppm	DLN	1-hr	BACT; operational
REGION 5	IL	Sep-99	Enron, Des Plaines Green Land	8	0	83 MW	NG	SC	3,250	9/12/15 ppm	DLN	an/mo/hr	BACT; Ox Cat rejected at $6800/ton
REGION 5	IL	Jan-00	Enron, Kendall New Century	8	0	83 MW	NG	SC	3,300	9/12/15 ppm	DLN	an/mo/hr	BACT; Ox Cat rejected at $6700/ton
REGION 5	IL	Jan-00	LS Power, Nelson Project	4		220 MW	NG; FO	SC	2,549 total, 2,000 each	25/15	DLN	1-hr	Synth Minor; minor until test under 15 ppm
REGION 5	IL	draft permit	Duke Energy	8	0	83 MW	NG; FO	SC	2,000; 500 FO	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 5	IN	Jul-99	Vermillion Generating Station	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500	12/15 ppm NG; 42 ppm FO	DLN and WI	an	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
REGION 5	IN	applic. under review	DeSoto Generating Station	8		GE 7EA (80 MW)	NG	SC	2,500	15 ppm NG (12 ppm); 42 ppm FO	DLN	1 hr (ann.); 1 hr	BACT
REGION 5	MN	draft permit	Lakefield Junction	6		GE model PG7121EA (92 MW)	NG; FO	SC	7,300	9 base, 25 peak, 42 FO	DLN, WI	3-hr	PSD; SCR rejected @ $11,500/ton; Ox Cat rejected at $3000/ton
REGION 5	OH	Jul-99	Duke Energy Madison LLC	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.)	BACT; SCR rejected at $19,000/ton; Ox Cat rejected at $9000/ton
REGION 5	WI	Jan-99	RockGen Energy	3		GE 7FA (175 MW)	NG; FO	SC	3,800 Total, 800 FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst; 1 hr	BACT; SCR not chosen; cost $23,018/ton; Ox Cat rejected at $15 K/ton
REGION 5	WI	Feb-99	Manitowoc Public Utility	1		GE Frame 5 (24.5 MW)	NG; FO	SC	2,328 Total	77 ppm NG; 77 ppm FO	WI	1-hr	BACT
REGION 5	WI	Feb-99	Southern Energy	2		GE 7FA (180 MW)	NG; FO	SC	8,760 Total, 699 FO	12/15 ppm NG; 42 ppm FO	DLN	24 hr/inst; 1 hr	BACT; Ox Cat rejected at $14 K/ton
REGION 5	WI	Jul-99	Wisconsin Public Service	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	BACT; SCR rejected at $13,866/ton; Ox Cat rejected at $6053/ton incremental cost
REGION 5	WI	draft permit	Wisconsin Electric	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	BACT; SCR rejected at $10,257/ton; Ox Cat rejected at $5984/ton incremental cost
REGION 7	KS	draft permit	Western Resources	3		2 - 100 MW, 1 - 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
REGION 7	MO	1-96	Kansas City Power & Light - Jackson	1		(200 MW)	NG	SC					
REGION 7	MO	draft permit	AECI - Nodaway	2		(100 MW)	NG	SC		25 ppm	DLN		
REGION 7	MO	applic. under review	Kansas City Power & Light - Jackson	2		(75 MW)	NG	SC		9 ppm	DLN		
REGION 7	MO	applic. under review	Duke Energy - Audrain	8		GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 1-hr avg.); 42 ppm FO	DLN; WI		
REGION 7	MO	applic. under review	Duke Energy - Bollinger	8		GE 7EA (80 MW)	NG	SC	2,500	12 ppm (15 ppm 1-hr avg.)	DLN		
REGION 7	NE	7-99	Omaha Public Power	4		(25 MW)	NG; FO	SC		25 ppm NG; 42 ppm FO	WI		
REGION 7	NE	6-99	Lincoln Electric System	1		(90 MW)	NG; FO	SC		25 ppm NG; 42 ppm FO	DLN; WI		
REGION 8	CO	final 4/99	Colorado Springs Utilities/Nixon (66 MW)	2		GE PG6541(B)	NG	SC	8,660 (both CTs)	15 ppm	DLN	1-hr	did not trigger BACT for CO

Region	State	Permit Date	Facility	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NO_x Limit	Control Method	Avg. Time	Comments
REGION 8	CO	final 8/99	Fulton Cogeneration /Manchief (284 MW)	2		SW V84.3A1	NG	SC	8,760	15 ppm	DLN	1-hr	
REGION 8	CO	applic. 11/99	KN Energy/Front Range Energy Associates - Ft. Lupton (160 MW)	4		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
REGION 8	CO	applic. 3/00	Platte River Power Authority/Rawhide (82 MW)	1		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
REGION 8	CO	draft permit 5/00	Public Service Co. of Colo./Ft. St. Vrain Unit 4 (242 MW)	1	1	GE PG7241 (FA)	NG	SC/CC	8,760	4 ppm (CC); 9 ppm (SC)	DLN+SCR (CC); DLN (SC)	24-hr	plan startup 6/2001;
REGION 8	CO	applic. 11/99	Front Range Power Project/Ray Nixon Sta., Fountain, CO (480 MW)	2	2	GE Frame 7	NG	SC/CC	8,760	9 ppm/16 ppm w/ DB	DLN		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
REGION 8	SD	applic. 11/99	Black Hills Power & Light/Lange CT Facility (80 MW)	2		GE LM6000PD	NG	SC	8,760	25ppm (proposed)	DLN	24-hr	Characterized as peaking plant, but not restricted in operating hours
REGION 8	WY	final 3/00	Black Hills Power & Light/Niel Simpson II (80 MW)	2		GE LM6000PD	NG	SC	8,760	25 ppm	DLN	24-hr	Region provided written comment disagreeing w/ NOx BACT determination; characterized as peaking plant, bur not restricted in operating hours
REGION 8	WY	final 2/98	Two Elk Generation Partners (33 MW turbine)	1		GE LM5000	NG	SC	8,760	25 ppm	DLN	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

5.3.4.1 Low NO_x Combustors

Dry low-NO_x combustion control techniques reduce NO_x emissions without injecting water or steam (hence "dry").

Lean premixed combustors are currently available for certain turbine models in the range of 9–25 ppm NO_x. The lowest dry low- NO_x emission rate turbines on the market are the GE 7FA, which are proposed for the Midway Energy Facility. Lean premix designs reduce peak combustion temperatures, thereby reducing thermal NO_x; however fuel NO_x formation (oil contains significant fuel-bound nitrogen) is not reduced with this technique. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs simultaneously with combustion. A lean premixed combustor premixes natural gas and air prior to combustion. Premixing results in a homogenous fuel lean air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. An air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is often used to maintain combustion stability in this fuel-lean environment.

5.3.4.2 Continuously Achievable NO_x Emissions for Peakers

The GE 7FA turbines proposed for the Midway Energy Facility employ General Electric's state-of-the-art 9 ppm NO_x Dry low-NO_x (DLN) Combustion technology. EPA acknowledges that 9 ppm is the lowest Dry low- NO_x emission level that has been demonstrated for any combined cycle, base load turbine. Since add-on controls have previously been shown to be not technically feasible for application to the proposed dual fuel fired simple cycle peakers (and would not be cost effective in any case), the lowest emission rate continuously achievable using Dry low- NO_x combustors represents the next candidate for BACT. The Midway Energy Facility will utilize the lowest emitting DLN turbine technology on the market today, which therefore represents Best Available Control Technology (BACT).

When evaluating achievable NO_x emission rates for peaking applications, it is important to first qualify General Electric's 9 ppm guarantee for the 7FA. GE guarantees that the turbine will achieve 9 ppm of NO_x, corrected to 15% O_2, in new and clean condition, under steady-state operation, and corrected to international standards organization (ISO) ambient conditions. This guarantee, coupled with a 40 CFR Part 60 one-time compliance test, or with a 24-hour averaging time Continuous Emissions Monitoring System (CEMS) may be achievable during base load operation, but is not continuously achievable during peaking operation. A base load turbine normally operates 24 hours per day, as near as possible to its full load output. Flame stability is crucial in a dry low NO_x combustor. To maintain flame stability during transient conditions, GE uses a combination of richer pre-mix and a conventional pilot flame. These factors may increase NO_x emissions to 12-15 ppm during transient conditions. Even through emission rates may climb to 12 or 15 ppm during transient load changes, the duration of such load changes is short compared in a base loaded unit with the 24-hour averaging time of the permit compliance limit.

Peaking turbines, on the other hand, spend very little of their operation at steady state conditions. In a daily peaking cycle, a peaking turbine may be called upon to start up at 2:30 p.m., be at full load by 3:00 p.m. and commence shut down sequence at 5:00 p.m. It is even possible that the unit could be dispatched at several different loads during this event. It can be seen that the peaking turbine exhibits a much greater ratio of transient operation to steady state operation than would a base load turbine.

The "9 ppm" DLN 7FA turbine cannot meet a continuous compliance limit of 9 ppm, in that a substantial portion of its operating hours will be at non-steady state conditions, with DLN emission levels rising to 12-15 ppm. GE does not guarantee that the 7FA turbine will continuously meet 9 ppm during such peaking operation, and no turbine in the US has demonstrated the ability to continuously meet 9 ppm in peaking service. Transient load changes are part of normal operation for a peaker – they cannot be exempted from compliance limits as start-up" or "malfunction".

Since the Midway Energy Center Facility will continuously monitor NO_x emissions to demonstrate continuous compliance with enforceable permit limits, the permitted NO_x emission limit must be set at a value that can be complied with on a continuous basis in actual peaking operation. This level is 12 ppm. In addition to the 12 ppm limit Midway Energy Center Facility proposes to demonstrate compliance with the 9 ppmvd @ 15% O_2 emission concentration guaranteed by GE during an initial and annual performance stack tests.

While most of the discussion has been dealing with achievable NO_x emissions limits for natural gas fired operation, Midway Development Company, L.L.C. proposes a NO_x emission limit of 42 pmvd @ 15% O_2 achieved using water injection. Similar to other permits issued in Florida Midway Development Company L.L.C. proposes that within 18 months after the initial compliance test, an engineering report will be prepared regarding the lowest NO_x emission rate that can be consistently achieved while firing distillate oil. This lowest NO_x emission rate would account for long-term performance expectations and reasonable operating margins. Based on the results of this report, the NO_x emission limit for distillate oil fired operation could be lowered.

5.3.4.3 Summary of Gas Turbine NO_x BACT

Midway Development Company L.L.C. proposes to implement NO_x BACT through the application of state-of-the-art GE 7FA turbines with "9 ppm" steady-state capable combustor technology as demonstrated during the initial and annual stack tests. Using these machines in peaking service will result in emissions that vary between 9-15 ppm during actual operation, resulting in a long-term compliance limit of 12 ppm with natural gas and 42 ppm (water injected) on distillate oil. This level represents the lowest dry low NO_x emission rate that is continuously achievable in peaking operation (both transient and steady state) for the Midway Energy Facility. This is equivalent to or more stringent than other recent BACT decisions for dual fuel simple cycle peaking projects using DLN for NO_x control. There is no operational facility for the GE 7FA turbine demonstrating the ability to continuously achieve short term or annual NO_x limits lower than 12 ppm under the rigors of peaking service. Midway Development Company, L.L.C. concludes that BACT for gas/oil fired peaking turbines is the current generation of General Electric 7FA "9 ppm" dry low NO_x combustors with a compliance limit of 12 ppmvd corrected to 15 percent oxygen while firing natural gas, and 42 ppmvd corrected to 15 percent oxygen while firing No. 2 distillate oil.

5.3.5 Natural Gas Fuel Heater

Based on a review of the RACT/BACT/LAER Clearinghouse the top NO_x control technology for heaters which fire less than 20 MMBtu/hr is the use of Low-NO_x burners. For a heater of this size, with limited hours of operation add-on control technology would not be cost effective. Midway Energy Facility will install a natural gas fired fuel heater equipped with Low-NO_x burner technology which will achieve a NO_x emission rate of less than 0.10 lb/MMBtu which will result in annual NO_x emissions of less than 2.3 tons/year. It should also be noted that the natural gas fuel heater is incorporated into this project to ensure that the natural gas fuel being used in the three combustion turbines is at the appropriate temperature for effective operation of GE's advanced DLN system.

5.4 BACT for Carbon Monoxide

5.4.1 Formation

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a low NO_x emission rate achieved through flame temperature control (by water injection or aggressive dry lean pre-mix) tends to result in higher levels of CO emissions. Thus, a compromise must be established whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emission rates at acceptable levels.

5.4.2 Gas Turbines-Ranking of Available Control Techniques

CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Alternative Simple-Cycle turbine CO control methods include exhaust gas cleanup methods such as high temperature catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

A review of EPA's RACT/BACT/LAER Clearinghouse (Appendix C) indicates several levels of CO control which may be achieved for Simple-Cycle natural gas fired gas turbines. High temperature oxidation catalyst (analogous to high temperature SCR) is a relatively new add-on control technology that could be applied to Simple-Cycle peaking turbines. The Carson Energy project in California, a 64 MW peaker, uses this technology. As shown in Appendix C, the majority of projects in the Clearinghouse reference combustion controls (burner design) as BACT for CO. Emission levels and control technologies have been identified and ranked as follows:

- 2 to 6 ppm: High-temperature CO oxidation catalyst
- 10 to 50 ppm: Good combustion practices

These levels of CO control are evaluated in terms of Best Available Control Technology in the following sections.

5.4.2.1 LAER: 2 to 6 ppm CO with High-Temperature Catalytic Oxidation

The most stringent CO control level available for Simple-Cycle gas turbines would be achieved with the use of a high temperature (zeolite based) oxidation catalyst system, which can remove up to 90 percent of CO in the flue gas (Booth, 1998). According to the list of Simple-Cycle turbines in the RACT/BACT/LAER Clearinghouse with limits for CO, none are listed with high-temperature oxidation catalyst systems. Our search identified one Simple-Cycle peaking project in California, and Englehard offers the technology commercially. A high temperature CO oxidation catalyst is, therefore, concluded to represent a technically feasible add-on control technology to control CO from natural gas fired, Simple-Cycle turbines. This zeolite catalyst technology, however, exhibits many of the same start-up responsiveness limitations and negative environmental impacts expressed previously for high temperature SCR. The use of an oxidation catalyst would extend the startup period for the combustion turbines, and increase back pressure on the turbine, which in both cases would contribute to increased emissions of pollutants. Also the installation of an oxidation catalyst would contribute to increased formation of SO_3, which is a precursor for PM_{10} and H_2SO_4 formation.

<u>Technical Analysis</u>

As with SCR catalyst technology for NO_x control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to occur. Rather, the oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include turbine back pressure losses, unknown catalyst life due to masking or poisoning, greater emissions and reduced market responsiveness due to extended start-ups, and potential collateral increases in emissions of SO_3, sulfuric acid mist and condensible PM_{10}.

As with SCR, traditional CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 900°F. According to Englehard, high-temperature oxidation catalyst is rated up to 1,200°F, so a dilution air system would not be required for the proposed General Electric 7 FA turbines.

Typical pressure losses across an oxidation catalyst reactor are in the range of 1.5 to 3.0 inches of water (Englehard, 1997). Pressure drops in this range correspond roughly to a 0.15 to 0.30 percent loss in power output and fuel efficiency (General Electric, 1997), or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

All catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement has been considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life, but no operating units were identified with more than about 3,500 hours. Periodic testing of catalyst material is necessary to predict actual catalyst life for a given installation. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system would also be expected to control as much as 40 percent of hydrocarbon (VOC) emissions.

Like high-temperature SCR, this technology has yet to be demonstrated-in-practice on Simple-Cycle turbines in this size range. It is, however, a passive control technology (does not require NH_3 injection) and can withstand higher turbine exhaust temperatures. It would however, limit the project's ability to come on line quickly enough to meet peak power market demand.

Environmental Analysis

A CO catalyst will also oxidize other species within the turbine exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, but will be further oxidized to SO_3 across a high temperature catalyst (70% conversion is assumed). SO_3 will be emitted and/or combined to form H_2SO_4 (sulfuric acid mist) in the exhaust stack or downstream in the ambient air. These sulfates condense as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and VOC, but would increase emissions of PM_{10} and $PM_{2.5}$.

The negative environmental impacts associated with this technology are less than for high-temperature SCR since no ammonia slip or ammonium salts are emitted. Collateral emissions due to efficiency losses or forced outages would still result in negative regional environmental impacts.

Economic Analysis

A high-temperature CO oxidation catalyst cost effectiveness evaluation was performed for the proposed Simple-Cycle General Electric 7FA turbines. Capital and annual costs associated with installation of a high temperature CO oxidation catalyst system were obtained from Engelhard, the vendor of high-temperature oxidation catalyst systems. Based on the quote from Engelhard (see Appendix C), the purchased equipment cost for each turbine is estimated at $1,807,450. Capital costs include the catalytic reactor, support structure, turbine transition piece, spare parts and catalyst charge, freight, engineering and design, and installation. As shown in Table 5-5, when adding direct installation costs and indirect costs, the total capital cost (per turbine) is estimated at $2,992,100. Catalyst replacement is treated separately in this analysis as an operating cost. Annual operating costs, also summarized in Table 5-5, include operating labor (0.5 hour/shift), routine inspection and maintenance, spent catalyst replacement, and lost cycle efficiency due to increased back pressure. Annualized catalyst replacement cost was calculated based on a 3-year life.

Table 3-2 presents a worst-case CO emission estimate for the proposed project of 240 tons per year (79.6 tons per year per turbine). This estimate is based on 2,000 hours per year per turbine on natural gas at 50°F and 100 percent load and 1,500 hours per year per turbine on distillate oil at 50 °F and 100 percent load, which serves as a conservative estimate of the maximum annual emissions for the proposed turbines. The amount of CO removed annually by the oxidation catalyst would be 71.6 tons per turbine, based on estimated removal efficiency of 90 percent. The total annualized cost of oxidation catalyst for this case is estimated at $2,277,300, resulting in an overall cost-effectiveness of about $31,800 per ton of CO removed which is a prohibitive figure for non-LAER control of CO.

5.4.2.2 Next Best Level of Control – 10 to 50 ppm with Combustion Control

The next best level of control is the General Electric 7FA combustors optimized CO emission rate of 9 ppmvd while firing natural gas and 20 ppmvd while firing distillate oil. This level of control is available, will not cause negative operational or environmental impacts, is cost effective, and represents BACT.

Summary

The use of a high temperature oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) NO_x, SO_2, and CO_2 emissions, is not cost effective, and does not represent BACT for the Midway Energy Center. Further, it would also lengthen peaking start-up times and limit the responsiveness of the project in its ability to address the peak power market. The next best level of control, 9 ppmvd while firing natural gas and 20 ppmvd while firing distillate oil using combustion control, is concluded to represent BACT for this facility.

5.4.3 Natural Gas Fuel Heater

The natural gas fuel heater will employ good combustion control for CO which has been determined to represent BACT for this source type. No add on control would be considered cost effective for control of CO emissions from this source.

Table 5-5 High Temperature Oxidation Catalyst (Carbon Monoxide) General Electric, Simple-Cycle, Model 7 FA

Control Efficiency (%)	90%

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	3,500
Natural Gas Firing (Normal Operation)	2,000
Distillate Oil Firing (Normal Operation)	1,500
Source(s) Controlled[1]	One Power Block, 175 MW
CO From Normal Natural Gas Operation (lb/hr)	29.6
CO From Distillate Oil Operation (lb/hr)	66.6
CO From Source(s) (tpy)	79.6
Site Specific Enclosure (Building) Cost	NA
Site Specific Electricity Value ($/kWh)	0.10
Site Specific Natural Gas Cost ($/MMBtu)	NA
Site Specific Operating Labor Cost ($/hr)	30
Site Specific Maint. Labor Cost ($/hr)	30

[1]CO emissions are based on data at 100% load and intake air chilled to maximum of 50°F.

Capital Costs[1]

Item	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$1,493,750	Scaled Engelhard quote + auxiliaries, A
b.) Instrumentation	$149,400	0.10 x A
c.) Sales taxes	$74,700	0.05 x A
d.) Freight	$89,600	0.06 x A
Total Purchased equipment cost, (PEC)	$1,807,450	B = 1.21 x A
2.) Direct installation costs		
a.) Foundations and supports	$144,600	0.08 x B
b.) Handling and erection	$253,000	0.14 x B
c.) Electrical	$72,300	0.04 x B
d.) Piping	$36,100	0.02 x B
e.) Insulation for ductwork	$18,100	0.01 x B
f.) Painting	$18,100	0.01 x B
Total direct installation cost	$542,200	0.30 x B
3.) Site preparation, SP	NA	NA
4.) Buildings, Bldg	NA	NA
Total Direct Cost, DC	$2,349,700	1.30B + SP + Bldg
Indirect Costs (installation)		
5.) Engineering	$180,700	0.10 x B
6.) Construction and field expenses	$90,400	0.05 x B
7.) Contractor fees	$180,700	0.10 x B
8.) Start-up	$36,100	0.02 x B
9.) Performance test	$18,100	0.01 x B
10.) Contingencies	$54,200	0.03 x B
11.) Simple Interest During Construction	$82,200	DC x 7% x 0.5 years
Total Indirect Cost, IC	$642,400	0.28B
Total Capital Investment (TCI) = DC + IC	**$2,992,100**	**1.58B + SP + Bldg**

1 See Appendix C, Tables C-1 and C-1A

Table 5-5 High Temperature Oxidation Catalyst (Carbon Monoxide) General Electric, Simple-Cycle, Model 7 FA (Continued)

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Press. Drop (in. W.C.)	3.0	Pressure drop - catalyst bed	Vendor
Power Output of Turbine (kW)	175,000		
Power Loss Due to Pressure Drop (%)	0.32%	0.105% for every 1" pressure drop	Vendor
Power Loss Due to Pressure Drop (kW)	551		
Unit Cost ($/kWh)	$0.10	Estimated Market Value	Estimate
Cost of Heat Rate Loss ($/yr)	$192,940		
Power Loss Due to Extended Startups (kW-hr)	13,125,000	Extended startup time due to catalyst bed	Estimate
Cost of Extra Startups ($/yr)	$1,312,500	$0.10/kWh	
Total Cost ($/yr)	$1,505,440		
2) Operating Labor			
Requirement (hr/yr)	218.75	1/2 hr/shift, 3,500 hours per year	OAQPS
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Cost ($/yr)	$6,560		
3) Supervisory Labor			
Cost ($/yr)	$980	15% Operating Labor	OAQPS
4) Maintenance			
Labor Req. (hr/shift)	218.75	1/2 hour per shift	OAQPS
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Labor Cost ($/yr)	$6,563		
Material Cost ($/yr)	$6,560	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$13,120		
7) Catalyst Replacement			
Catalyst Cost ($)	$670,000	Catalyst modules	Vendor
Catalyst Disposal Cost ($)	$50,000	Disposal of catalyst modules	Estimate
Sales Tax ($)	$33,500	5% sales tax in Indiana	Estimate
Catalyst Life (yrs)	3	n	OAQPS
Interest Rate (%)	7	i	
CRF	0.38	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$287,120	(Volume)(Unit Cost)(CRF)	
9) Indirect Annual Costs			
Overhead	$12,400	60% of O&M Costs	OAQPS
Administration	$59,800	2% of Total Capital Investment	OAQPS
Property Tax	$29,900	1% of Total Capital Investment	OAQPS
Insurance	$29,900	1% of Total Capital Investment	OAQPS
Capital Recovery	$332,100	10 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	$464,100		
Total Annualized Cost ($/yr)	**$2,277,300**		
Total CO Controlled (tpy)	**71.6**		
Cost Effectiveness ($/ton)	**$31,800**		

5.5 BACT for Particulate Matter and Trace Metals

5.5.1 Formation

Particulate (PM) emissions from natural gas and distillate oil combustion sources consist of inert contaminants in the fuel, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulates of carbon and hydrocarbons resulting from incomplete combustion, and condensibles, including sulfates and nitrates. Units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions. Trace metals that may be emitted from natural gas combustion are discussed in this section because they form a portion of particulate emissions. Lead and mercury, which are regulated in Florida's SIP regulations, may be a metal constituent of distillate fuel oils. However, neither lead nor mercury are estimated to emit more than the significant emission rates established in 40 CFR 52.21.

5.5.2 Gas Turbines

When the New Source Performance Standard for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA recognized that "particulate emissions from stationary gas turbines are minimal," and noted that particulate control devices are not typically installed on gas turbines and that the cost of installing a particulate control device is prohibitive (U.S. EPA, September 1977). Performance standards for particulate control of stationary gas turbines were, therefore, not proposed or promulgated.

The most stringent particulate control method demonstrated for gas turbines or diesel engines is the use of low ash fuel (such as natural gas or low sulfur transportation diesel) and the avoidance of catalytic technologies such as SCR when not required for LAER. No particulate matter or mercury-specific add-on control technologies are listed in the RACT/BACT/LAER Clearinghouse listings for Simple Cycle combustion turbines as shown in Appendix C. Proper combustion control and the firing of fuels with negligible or zero ash content (natural gas and 0.05% sulfur transportation diesel) is the predominant control method listed.

Add on controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas fired turbines. The use of ESPs or baghouse filters is technically infeasible, and does not represent an available control technology.

The use of negligible or zero ash fuels such as natural gas and low sulfur diesel, and good combustion control is concluded to represent BACT for PM control for the proposed Simple-Cycle peaking turbines and diesel engine. BACT for PM_{10} precludes the selection of high-temperature SCR for NO_x control as NH3 slip at 10 ppm could result in additional PM_{10} (and PM_{10} precursor) emissions.

5.5.3 Natural Gas Fuel Heater

The most stringent particulate control method demonstrated for, natural gas fired heaters is the use of low ash fuel (such as natural gas). Proper combustion control and the firing of fuels with negligible or zero ash content is the predominant control method listed in the RACT/BACT/LAER Clearinghouse for similar sources. Add-on controls, such as ESPs or baghouses, have never been applied to small natural gas fired heaters. The use of ESPs and baghouse filters is considered technically infeasible, and does not represent an available control technology.

5.6 BACT for Sulfur Dioxide and Sulfuric Acid Mist

5.6.1 Formation

Sulfur dioxide (SO_2) is exclusively formed through the oxidation of sulfur present in the fuel. The emission rate is a function of the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_2. Another by-product of sulfur oxidation is when sulfur trioxide (SO_3) combines with water to form sulfuric acid (H_2SO_4). As a condensable gas, the sulfuric acid will appear in mist form in the stack if the temperatures are sufficiently low for condensation to occur. Since the stack exhaust will be in the 1050°F – 1250°F range, and the boiling point of sulfuric acid is less than 650°F, sulfuric acid mist will not form in the stack.

5.6.2 Gas Turbines and Fuel Gas Heater

The proposed simple cycle gas turbines will fire pipeline-quality natural gas and low sulfur transportation grade distillate fuel, the natural gas fuel heater will fire pipeline-quality natural gas only. Pipeline grade natural gas typically averages between 1-10 grains of sulfur per hundred standard cubic feet gas. A review of EPA RACT/BACT/LAER Clearinghouse information shows low sulfur fuel as the only available SO_2 control method selected as BACT in previous determinations for gas turbines. This indicates that the firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel is the most stringent SO_2 control methodology that has been demonstrated in practice for any combustion turbine. Therefore, this evaluation concludes that that firing of pipeline quality natural gas and low sulfur transportation grade distillate fuel in the proposed Simple-Cycle peaking turbines and pipeline quality natural gas in the proposed fuel gas heater is BACT for SO_2.

If BACT were to be applied to H_2SO_4, which would preclude the use of an oxidation catalyst or SCR as the catalysts would further oxidize SO_2 to SO_3 which is a precursor of H_2SO_4. We should also state that H_2SO_4 would not be directly emitted from the turbine stack as the stack temperatures are too high. We should state that even though H_2SO_4 would not be emitted directly the test method used for sampling SO_2 if used could cause the formation of H_2SO_4 when the sample is cooled.

5.7 Summary and Conclusions

A summary of technologies determined to represent BACT for the MEC project is are presented in Table 5-6. Expected total emissions are summarized in Section 3 which are estimated based on 100% load for 3,500 hours per year including up to 1,500 hours per year of distillate oil operation and application of BACT as determined in this analysis.

Table 5-6 Summary of Selected BACTs

Pollutant	Gas Turbines
NO_x	Dry Low NO_x Combustors with Natural Gas (12 ppmvd, 15% O_2, 24 hour average, 9 ppmvd @ 15% O_2 during initial and annual performance tests), Water injection with Distillate Oil (42 ppmvd, 15% O_2)
CO	Good combustion control (9 ppmvd with Natural Gas, 20 ppmvd with Distillate Oil)
PM	Good combustion control; low ash, low sulfur fuel
SO_2	Low sulfur fuel; natural gas (2 grains S / 100 scf gas) distillate oil (0.05 wt% S)

6.0 AMBIENT AIR QUALITY IMPACT ANALYSIS

6.1 Overview of Analysis Methodology

The PSD rules require an analysis of the impact of the proposed facility on ambient concentrations of pollutants emitted in significant quantities, for which there is a National Ambient Air Quality Standard or PSD Increment. For the proposed facility, this includes NO_x, CO, SO_2, and PM_{10}. Although the project is not subject to PSD review for lead, the air quality standards analysis included a compliance assessment of this pollutant.

The ambient concentrations of PSD pollutants resulting from allowable emissions from the proposed facility are predicted using an approved U.S. EPA atmospheric dispersion model in accordance with U.S. EPA's "Guideline on Air Quality Models" (U.S. EPA, 1999). The atmospheric dispersion of emissions is simulated for a record of representative sequential hourly meteorological conditions over a historical five-year period. Ground-level concentrations at various averaging periods depending on the pollutant are predicted for a grid of ground-level model "receptors" surrounding the proposed facility. The following sections detail the specific aspects of the ambient air quality impact analysis.

6.2 Model Selection

The selection of an appropriate dispersion model must take into consideration the physical geometry of the sources, the local dispersion environment, and terrain characteristics. These factors, which formulate the basis for choosing one or more of the models recommended in the U.S. EPA modeling guidelines for both screening and refined modeling, are discussed below.

6.2.1 Physical Source Geometry

The sources of PSD pollutants from the proposed facility consist of high velocity, high temperature exhausts from stacks connected to the combustion turbines. This requires the use of a model capable of simulating the dispersion of buoyant releases from elevated point sources. The U.S. EPA modeling guidelines require the evaluation of the potential for physical structures to affect the dispersion of emissions from elevated point sources. The exhaust from stacks that are located within specified distances of buildings, and whose physical heights are below specified levels, may be subject to "aerodynamic building downwash" under certain meteorological conditions. If this is the case, a model capable of simulating this effect must be employed.

The analysis used to evaluate the potential for building downwash is referred to as a physical "Good Engineering Practice" (GEP) stack height analysis. Stacks with heights below physical GEP are considered to be subject to building downwash. In the absence of structural effects, U.S. EPA has established a "default" GEP height of 213 feet. Any portion of a stack above the maximum of the physical or default GEP height cannot be used in the dispersion modeling analysis for purposes of comparison to U.S EPA's ambient impact criteria.

Each of the three combustion turbines at the proposed facility will have its own stack. A GEP stack height analysis was performed for the proposed project configuration in accordance with U.S. EPA's guidelines (U.S. EPA, 1985). Per the guidelines, the physical GEP height, H_{GEP}, is determined from the dimensions of all buildings which are within the region of influence using the following equation:

$$H_g = H + 1.5L$$

where:

H = height of the structure within 5L of the stack which maximizes H_g, and

L = lesser dimension (height or projected width) of the structure.

For a squat structure, i.e., height less than projected width, the formula reduces to:

$$H_g = 2.5H$$

In the absence of influencing structures, a "default" GEP stack height is credited up to 65 meters (213 feet). The locations and dimensions of the various structures at the proposed facility relative to the exhaust stacks are depicted in Figure 6-1. An analysis of the potential for building downwash is presented below.

The significant structures of the proposed facility will include the turbine enclosures, turbine air intake structures, control room/electrical room/administration building, water storage tanks, and fuel storage tanks. U.S. EPA's Building Profile Input Processor (BPIP), as implemented in Lakes-Environmental *BPIP View* software, was used to determine the GEP stack height and to develop building input data for the modeling analysis. The output of the BPIP analysis is provided in Appendix D. A summary of the GEP analysis and the controlling building is provided in Table 6-1. The table lists the physical GEP stack height calculated for each influencing structure. Based on the BPIP analysis, the GEP stack height for the turbine stacks is 135 feet. Since the proposed height of the combustion turbine stacks is 80 feet, building downwash affects must be simulated in the dispersion modeling analysis. Also, since the stacks are less than the default GEP height of 213 feet, their full height can be considered in the modeling.

Figure 6-1 Location of Turbine Stacks Relative to Structures Included in the GEP Analysis

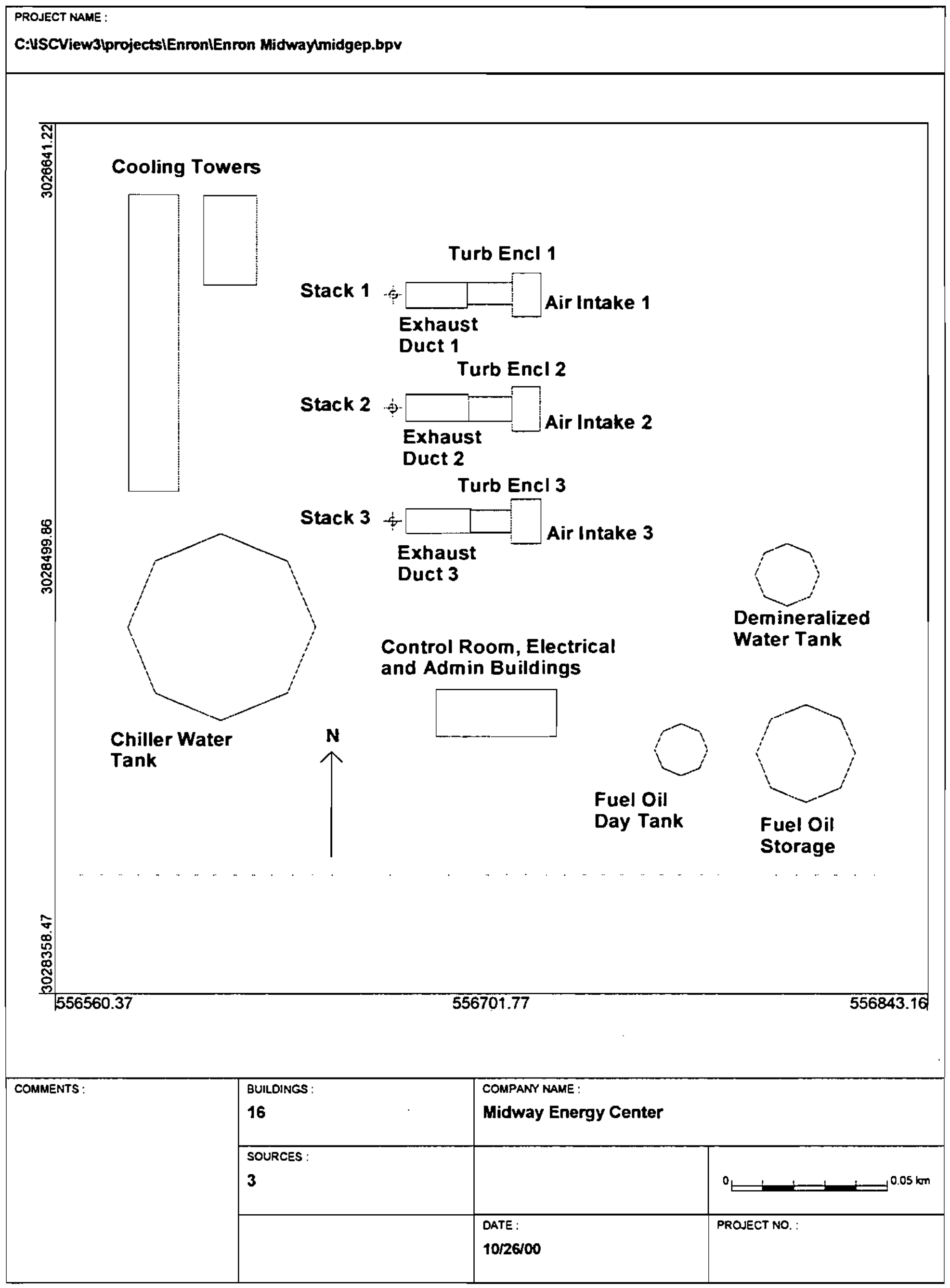

Table 6-1 Summary of GEP Analysis (Units in Feet)

Structure	Height	Length	Width	MPW[2]	GEP Formula Height	5L[3]	Distance to Turbine Stack [4]	Turbine Stack(s) Potentially Effected By Downwash Yes/No
Turbine Air Intake[1]	54	45	36	57	135	270	112	Yes
Turbine Enclosure [1]	45	49	23	54	113	225	62	Yes
Exhaust Duct [1]	27	62	26	67	67.5	135	0	Yes
Control/Admin Building	45	110	45	119	112.5	225	180	Yes
Chiller Water Tank	48	210	210	210	120	240	105	Yes
Demineralized Water Tank	48	59	59	59	120	240	380	No
Fuel Oil Day Tank	40	55	55	55	100	200	355	No
Fuel Oil Storage Tank	48	100	100	100	120	240	440	No
Chiller	8	310	50	315	20	40	135	No

(1) One associated with each turbine (see Figure 6-1).
(2) Maximum projected width.
(3) 5 times the lessor of the MPW or height is the maximum influence region.
(4) Closest distance relative to all turbine stacks.

6.2.2 Dispersion Environment

The selection and application of the model requires characterization of the local (within 3 km) dispersion environment as either urban or rural, based on a U.S. EPA-recommended procedure that characterizes an area by prevalent land use. This land use approach classifies an area according to 12 land use types. In this scheme, areas of industrial, commercial, and compact residential land use are designated urban. According to U.S. EPA modeling guidelines, if more than 50 percent of an area within a three-kilometer radius of the proposed facility is classified as rural, then rural dispersion coefficients are to be used in the dispersion modeling analysis.

For this analysis, the 1:24,000 scale United States Geological Survey (USGS) topographic maps for West Dixie Bend was obtained. Visual observation of the land use depicted on these maps clearly indicates that the region within 3 km is predominately rural.

6.2.3 Terrain Considerations

The U.S. EPA modeling guidelines require that the differences in terrain elevations, between the stack base and each location (receptor) at which air quality impacts are predicted, be considered in the modeling analyses. There are three types of terrain:

- simple terrain – locations where the terrain elevation is at or below the exhaust height of the stacks to be modeled;

- intermediate terrain – locations where the terrain is between the height of the stack and the modeled exhaust "plume" centerline (this varies as a function of plume rise, which in turn, varies as a function of meteorological condition);
- complex terrain – locations where the terrain is above the plume centerline.

Based on a review of USGS topographical maps, the area throughout the modeling domain is generally flat. The dispersion model must therefore be capable of simulating impacts on simple terrain only.

Based on a review of the factors discussed above, the ISCST3-Version 00101 dispersion model was selected for use in the modeling analysis.

6.3 Model Application

The ISCST3 model was used to calculate concentrations at simple receptor locations. The model was applied using the ISCST3 regulatory default option, in accordance with the U.S. EPA Guidelines.

6.3.1 Meteorological Data

The ISCST3 model requires a sequential hourly record of dispersion meteorology representative of the region within which the proposed source is located. In the absence of site-specific measurements, the EPA Guidelines recommend the use of data from nearby National Weather Service (NWS) stations, provided they are representative. For this analysis a five-year sequential meteorological data set was used consisting of surface observations and concurrent mixing height data from the NWS station at West Palm Beach International airport from 1987 through 1991. The West Palm Beach data are the closest representative data available and were recommended by the DEP for use in this application. The DEP provided the data in the processed format required for input to ISCST3.

6.3.2 Model Receptor Grid

A cartesian receptor grid was generated for use in the ISCST3 modeling. The grid consisted of densely spaced receptors at 100 meters apart starting at and extending to 3000 meters from the fenceline. Beyond 3000 meters, a spacing of 500 meters was used out to five kilometers from the facility. From six to ten kilometers, a spacing of 1000 meters was used. Between ten and twenty kilometers, a spacing of 2000 meters was used. Additional receptors were placed approximately every 50 meters along the property fence-line for increased resolution of impacts. As recommended by DEP, terrain elevations were not used for the receptors given that the terrain in the study area is generally flat. The extent of this grid was sufficient to capture maximum impacts.

Figure 6-2 shows the near-field receptors (out to three kilometers) including the near-field portion of the cartesian grid and fence-line receptors. The full cartesian receptor grid out to twenty kilometers is shown in Figure 6-3.

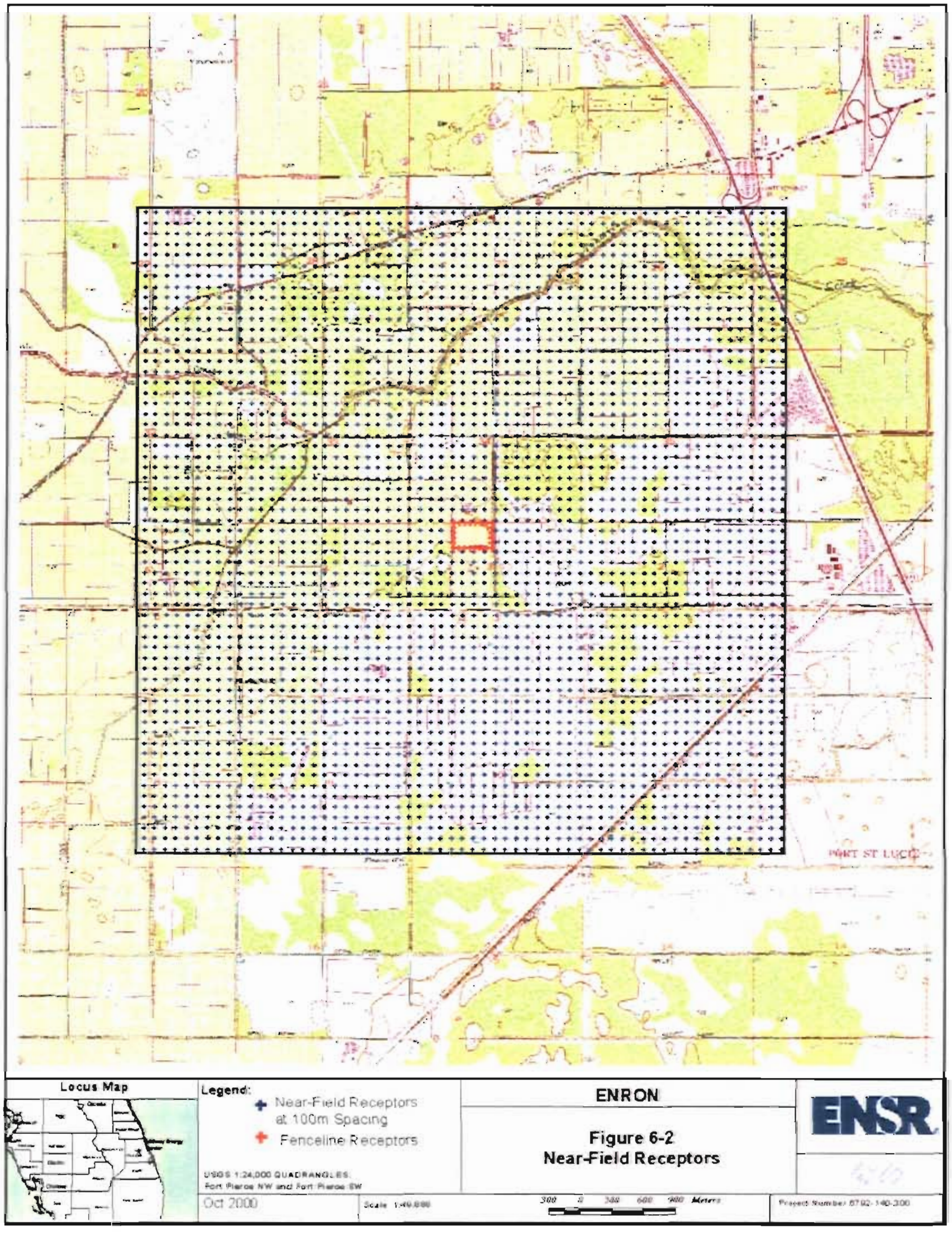

Figure 6-2
Near-Field Receptors

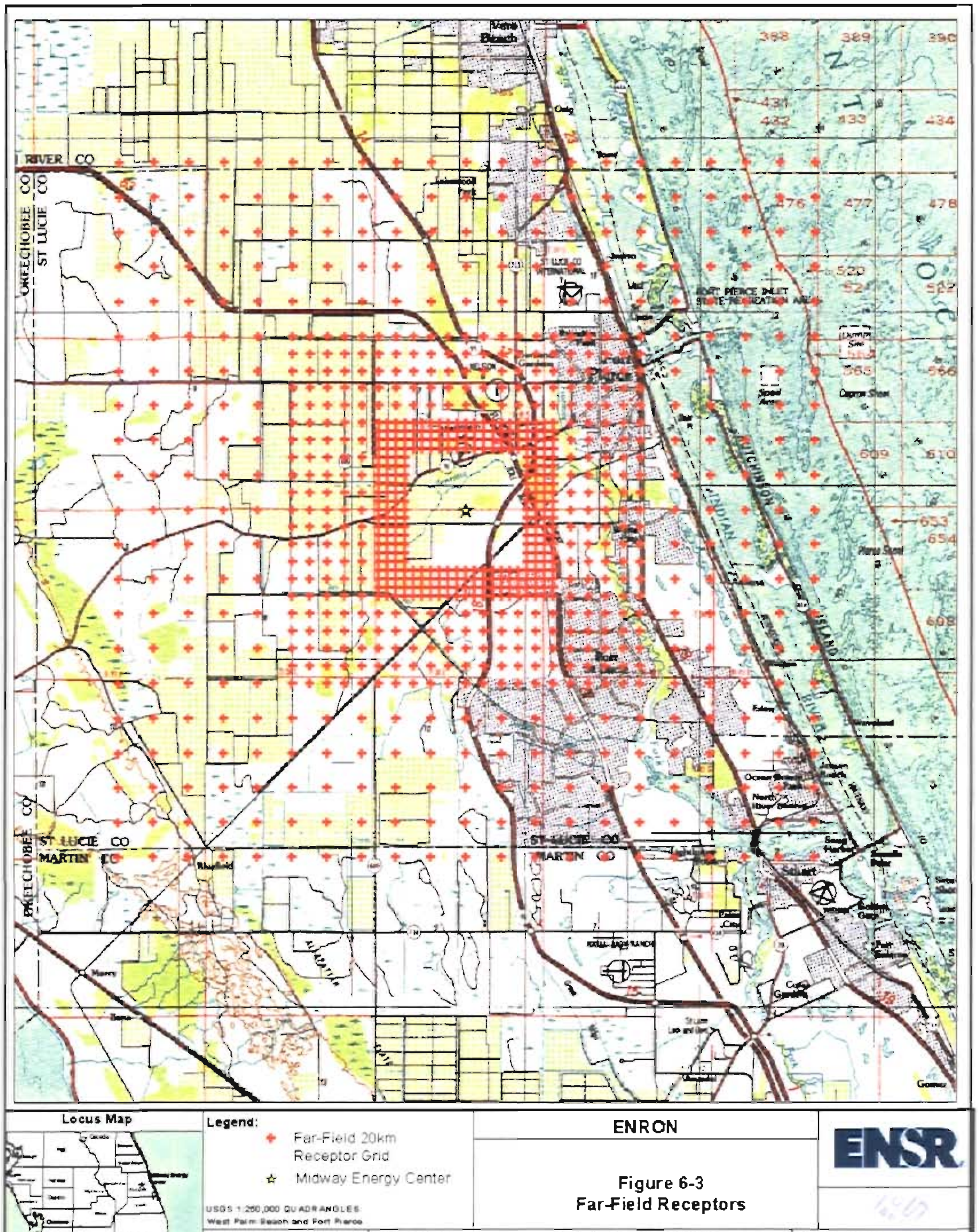

Figure 6-3
Far-Field Receptors

6.3.3 Physical Source and Emissions Data

The air dispersion modeling analysis was conducted with emission rates and flue gas exhaust characteristics (flow rate and temperature) that are expected to represent the worst-case parameters among the range of possible values for the GE turbine model under consideration. Because turbine emission rates and flue gas characteristics for a given turbine load vary as a function of ambient temperature and fuel use, data were derived for four ambient temperatures for each proposed fuel at each of the three operating load scenarios (100%, 75% and 50%). The temperatures selected were:

- 30°F, an extreme lower boundary
- 42°F,
- 50°F, the effective inlet air temperature when the chillers are operating
- 91°F, a representative upper boundary

A summary of the exhaust data and emission rates for the PSD regulated pollutants for each fuel at each temperature and the three operating loads is provided in Table 6-2 for the GE 7FA turbines. Detailed calculations of the emissions parameters are presented in Appendix B.

In order to conservatively calculate ground-level concentrations, a composite "worst-case" set of emissions parameters was developed for each proposed fuel for input to the modeling. For each operating load, the highest pollutant-specific emission rate, the lowest exhaust temperature and the lowest exhaust flow rate were selected. Table 6-3 summarizes the worst-case emissions parameters for the two fuels at three operating loads.

Wind-direction-specific dimensions of the structures potentially causing building downwash of the turbine stacks were derived using the U.S. EPA BPIP processor. The BPIP inputs to the ISCST3 model are provided in Appendix D.

6.4 Ambient Impact Criteria

The U.S. EPA has established specific ambient impact criteria against which to evaluate the impact of a proposed new source. These are listed in Table 6-4 for the pollutants considered in this analysis. A description of each of the criteria and the relevance to the PSD application is described below.

Table 6-2 Combustion Turbine Performance Data for Natural Gas and Distillate Fuel Oil Operation

100 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1149	1109	1100	1087
Exit Velocity (Ft./sec)		150.4	160.6	162.0	164.0
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	71.4	79.5	80.5	82.1
	CO	26.5	29.6	30.1	30.9
	SO_2	9.5	10.6	10.7	10.9
	PM_{10}	18.0	18.0	18.0	18.0

75 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1180	1147	1142	1134
Exit Velocity (Ft./sec)		125.8	130.8	131.5	132.7
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	58.0	63.4	64.1	65.3
	CO	21.8	23.5	23.8	24.3
	SO_2	7.8	8.5	8.6	8.8
	PM_{10}	18.0	18.0	18.0	18.0

50 % Load – Natural Gas

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1200	1194	1189	1182
Exit Velocity (Ft./sec)		106.9	111.3	111.8	112.4
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	45.9	50.3	50.8	51.6
	CO	18.4	19.5	19.7	20.0
	SO_2	0.9	1.0	1.1	1.1
	PM_{10}	18.0	18.0	18.0	18.0

Table 6-2 Combustion Turbine Performance Data for Natural Gas and Distillate Fuel Oil Operation (continued)

100 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1138	1088	1079	1065
Exit Velocity (Ft./sec)		154.4	165.0	166.5	168.6
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	289.6	321.0	325.5	332.1
	CO	59.5	66.6	67.8	69.6
	SO_2	90.3	100.2	101.6	103.6
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.03	0.03	0.03	0.03

75 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1186	1153	1148	1142
Exit Velocity (Ft./sec)		128.3	133.0	134.0	135.5
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	232.7	254.0	257.9	263.2
	CO	50.7	56.8	57.5	58.5
	SO_2	73.3	80.0	81.3	82.9
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.02	0.02	0.02	0.02

50 % Load –Distillate Fuel Oil

Parameter		Values			
Ambient Temperature (°F)		91	50	42	30
Stack Height (Ft.)		80	80	80	80
Stack Diameter (Ft.)		18.0	18.0	18.0	18.0
Exit Temperature (°F)		1200	1200	1200	1193
Exit Velocity (Ft./sec)		109.0	112.5	112.9	113.4
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	181.9	199.2	201.5	204.6
	CO	78.3	66.5	64.6	67.6
	SO_2	57.9	63.4	64.2	65.1
	PM_{10}	34.0	34.0	34.0	34.0
	Lead	0.02	0.02	0.02	0.02

Table 6-3 Worst-Case Turbine Stack Data for Dispersion Modeling

Natural Gas Operation

Parameter		Value		
Load (%)		100	75	50
Stack Height (Ft.)		80	80	80
Stack Diameter (Ft.)		18	18	18
Exit Temperature (°F)		1087	1134	1182
Exit Velocity (Ft./sec)		150.4	125.8	106.9
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	82.1	65.3	51.6
	CO	30.9	24.3	20.0
	SO_2	10.9	8.8	7.0
	PM_{10}	18.0	18.0	18.0

No. 2 Fuel Operation

Parameter		Value		
Load (%)		100	75	50
Stack Height (Ft.)		80	80	80
Stack Diameter (Ft.)		18	18	18
Exit Temperature (°F)		1065	1142	1193
Exit Velocity (Ft./sec)		154.4	128.3	109.0
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	332.1	263.2	204.6
	CO	69.6	58.5	78.3
	SO2	103.6	82.9	65.1
	PM_{10}	34.0	34.0	34.0
	Lead	0.028	0.023	0.018

Table 6-4 Ambient Impact Criteria[1]

Pollutant	Averaging Period	NAAQS		Maximum Allowable PSD Class II Increments	PSD Significant Monitoring Concentration	PSD Class II Significant Impact Levels	PSD Class I Significant Impact Levels
		Primary	Secondary				
NO_2	Annual	100	100	25	14	1	0.1
CO	1-hour	40,000	NA	NA	NA	2,000	NA
	8-hour	10,000	NA	NA	575	500	NA
PM_{10}	24-hour	150	150	30	10	5	0.3
	Annual	50	50	17	NA	1	0.2
SO_2	3-hour	NA	1300	512	NA	25	1.0
	24-hour	365	NA	91	13	5	0.2
	Annual	80	NA	20	NA	1	0.1
Lead	Quarter	1.5	1.5	NA	NA	NA	NA

[1] All values in µg/m^3. Annual averages are the maximum over all receptors. Short-term averages are the highest of the second-highest concentration over all receptors.
NA = Not Applicable

National Ambient Air Quality Standards (NAAQS)

National Ambient Air Quality Standards (NAAQS) are set by U.S. EPA, based on specific health and welfare effects criteria. Hence the term "criteria" pollutants. Ambient air refers to the air to which the general public is exposed, not the air inside buildings or in workplaces. The combined impacts of all existing sources cannot exceed the NAAQS. The primary NAAQS are established to protect the health of sensitive individuals. The secondary NAAQS are established to protect the general welfare of the public-at-large from adverse impacts on air quality related values such as visibility.

Allowable PSD Increments

The PSD increments are maximum allowable incremental increases in the ambient concentrations of the criteria pollutants in NAAQS attainment areas. The net combined impacts of all emissions increases and decreases from all sources occurring after a specified baseline date cannot exceed the PSD Increments. The PSD Class II increments apply to most areas of the country, including most of Florida with the exception of the designated PSD Class I areas. PSD Class I areas are National Parks and Wilderness Areas designated by U.S. EPA for special protection, including tighter PSD increments. The nearest PSD Class I area to the proposed facility is the Everglades National Park located about 180 kilometers to the southwest. New sources are presumed to have an insignificant impact on a PSD Class I area if maximum modeled impacts are less than the levels shown in Table 6-4. Since long range transport modeling involving the use of the CALPUFF dispersion model is required for the Class I impact assessment, a separate analysis is being completed for this assessment in coordination with the National Park Service Air Quality Division. The results of the PSD Class I area assessment will be submitted as a supplement to this permit application.

PSD Significant Monitoring Concentrations

PSD applicants can be granted a discretionary waiver from PSD pre-construction air quality monitoring requirements if the modeled impacts of the new source are below these concentrations.

PSD Significant Impact Levels

As can be seen from the concentrations representing these levels, the Significant Impact Levels (SILs) are small fractions of the NAAQS and PSD increments. The U.S. EPA guidelines require these levels to be used to determine the extent of the area surrounding a proposed source within which the source could significantly add to ambient air quality concentrations. For proposed sources whose impacts are above these levels, an analysis of the combined impacts of the proposed source with other existing sources is required. If a proposed source's impacts are below these levels it is considered to be unable to either cause or contribute to violations of the NAAQS, PSD Class II, or Class I increments. Therefore, a cumulative impact assessment is not required.

6.5 Results of Ambient Air Quality Impact Analysis

The emissions from the turbine stacks (3) were modeled with ISCST3 to estimate the maximum concentrations for the criteria pollutants including NO_x, PM/PM_{10}, SO_2, CO, and lead for each year of meteorological data. Note that the modeling of annual impacts reflects limited operation of the combustion turbines (3500 hours/year/turbine including up to 1500 hours/year/turbine of distillate fuel oil usage).

Class II Area Receptors

Tables 6-5 and 6-6 provide summaries of the ISCST3 modeling results for NO_x, PM/PM_{10}, SO_2, CO, and lead for the Class II cartesian grid and fence-line receptors for natural gas and oil firing, respectively. The maximum air concentrations over the five years modeled and corresponding receptor locations are listed for each turbine load case (100%, 75% and 50%). The modeling results

Table 6-5 ISCST3 Modeling Results for Natural Gas

100% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.020	547670	3033548
PM-10	24-hour	0.149	540670	3038548
	Annual	0.004	547670	3033548
SO_2	3-hour	0.369	562670	3012548
	24-hour	0.090	540670	3038548
	Annual	0.003	547670	3033548
CO	1-hour	2.469	555670	3029848
	8-hour	0.619	538670	3024548

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

75% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.019	547670	3033548
PM-10	24-hour	0.224	556730.6	3028621
	Annual	0.005	547670	3033548
SO_2	3-hour	0.601	556770	3028648
	24-hour	0.110	556730.6	3028621
	Annual	0.003	547670	3033548
CO	1-hour	4.977	556770	3028648
	8-hour	0.908	556730.6	3028621

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

50% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.017	547670	3033548
PM-10	24-hour	0.323	556580.9	3028573
	Annual	0.006	547670	3033548
SO_2	3-hour	0.622	556470	3028548
	24-hour	0.126	556580.9	3028573
	Annual	0.002	547670	3033548
CO	1-hour	4.744	556770	3028648
	8-hour	0.881	556730.6	3028621

* Annual concentrations based on a maximum of 3500 hours/year of natural gas use.

Table 6-6 ISCST3 Modeling Results for Distillate Oil

100% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.034	547670	3033548
PM-10	24-hour	0.277	540670	3038548
	Annual	0.004	547670	3033548
SO_2	3-hour	3.441	562670	3012548
	24-hour	0.844	540670	3038548
	Annual	0.011	547670	3033548
CO	1-hour	5.546	555670	3029848
	8-hour	1.371	538670	3024548
Lead	24-hour	2.28E-04	540670	3038548

* Annual concentrations based on a maximum of 1500 hours/year of oil use.

75% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.032	547670	3033548
PM-10	24-hour	0.414	556730.6	3028621
	Annual	0.004	547670	3033548
SO_2	3-hour	5.536	556770	3028648
	24-hour	1.009	556730.6	3028621
	Annual	0.010	547670	3033548
CO	1-hour	11.721	556770	3028648
	8-hour	2.135	556730.6	3028621
Lead	24-hour	3.41E-04	556730.6	3028621

* Annual concentrations based on a maximum of 1500 hours/year of oil use.

50% Load

Pollutant	Averaging Period	Maximum Concentration (μg/m³)*	Receptor Location	
			UTM East (m)	UTM North (m)
NO_X	Annual	0.029	547670	3033548
PM-10	24-hour	0.593	556580.9	3028573
	Annual	0.005	547670	3033548
SO_2	3-hour	5.638	556470	3028548
	24-hour	1.136	556580.9	3028573
	Annual	0.009	547670	3033548
CO	1-hour	18.168	556770	3028648
	8-hour	3.371	556730.6	3028621
Lead	24-hour	4.88E-04	556580.9	3028573

* Annual concentrations based on a maximum of 1500 hours/year of oil use.

for all years of modeling are provided in Appendix E. Note that in Table 6-5 (results for natural gas), the maximum annual concentrations are based on a maximum of 3500 hours/year of natural gas firing (i.e., the results have been scaled by a factor of 3500/8760). Similarly, in Table 6-6 (results for oil), the maximum annual concentrations are based on a maximum of 1500 hours/year of oil firing (i.e., the results have been scaled by a factor of 1500/8760).

A comparison of the overall maximum pollutant impacts with the Class II Significant Impact Levels is presented in Table 6-7. For each pollutant and averaging period, the table lists the maximum predicted concentration for all fuels, years of meteorology, and worst-case turbine operating load. All of the modeled concentrations are below the SILs. Based on these results it can be concluded that the proposed facility will neither cause nor contribute to a violation of the NAAQS or PSD Class II increments. It is also pointed out that these impacts are below the relevant PSD significant monitoring concentrations as well. Thus, the facility is eligible for a waiver from pre-construction monitoring.

Table 6-7 Comparison of Maximum ISCST3 Concentrations to Class II Significant Impact Levels

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)*	SIL ($\mu g/m^3$)
NO_X	Annual	0.046	1
PM-10	24-hour	0.593	5
	Annual	0.008	1
SO_2	3-hour	5.638	25
	24-hour	1.136	5
	Annual	0.012	1
CO	1-hour	18.168	2,000
	8-hour	3.371	500
Lead**	Quarterly	4.88E-04	1.5

*** Annual concentrations based on a worst-case composite of maximum natural gas concentration scaled by 2000 hours/year plus maximum oil concentration scaled by 1500 hours/year.**

**** Lead concentration is conservatively represented by the maximum 24-hour value. There is no SIL for Lead. The lead concentration is compared to the NAAQS.**

7.0 ADDITIONAL IMPACTS

The preceding sections of this permit application have focused on demonstrating the proposed action will incorporate Best Available Control Technology and will not have a significant impact on air quality. Beyond consideration of these basic air quality concerns, PSD regulations require a review of some of the more subtle effects a project may induce. The following section discusses the potential impacts which may result from the proposed project with respect to the following:

- Vegetation and Soils
- Associated Growth
- PSD Class I Area Impacts – Air Quality Increments, Regional Haze, and Deposition

7.1 Vegetation and Soils

The project lies in an area of primarily agricultural use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. The following discussion reviews the project's potential to impact its surroundings, based on the facility's PTE and the model-predictions of maximum ground level concentrations of SO_2, NO_x and CO, the PSD-applicable pollutants of concern for potential impact to soils and vegetation.

The criteria for evaluating impacts on soils and vegetation is taken from U.S. EPA's A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (U.S. EPA 1980). Table 7-1 lists the U.S. EPA suggested criteria for the gaseous pollutants emitted directly from the proposed facility and the predicted facility impacts. These criteria are established for sensitive vegetation and crops exposed to the effects of the gaseous pollutants through direct exposure. Adverse impacts on soil systems result more readily from the secondary effects of these pollutants' impacts on the stability of the soil system. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. Thus, the Table 7-1 criteria have been applied to the proposed facility to evaluate impacts on both soils and vegetation. As shown in Table 7-1, the results clearly indicate that no adverse impacts will occur to sensitive vegetation, crops, or soil systems as a result of operation of the proposed facility.

Table 7-1 Comparison to U.S. EPA Criteria for Gaseous Pollutant Impacts on Natural Vegetation and Crops

Pollutant	Averaging Time*	Minimum Impact Level for Affects On Sensitive Plants ($\mu g/m^3$)	Maximum Impact of Proposed Facility ($\mu g/m^3$)
SO_2	1 hour	917	16.61
	3 hours	786	5.64
	Annual	18	0.012
NO_x	4 hours	3760	17.72
	8 hours	3760	9.61
	1 month	564	3.57
	Annual	94	0.046
CO	1 week	1,800,000	1.37

*** 24-hour average used to conservatively represent 1-week and 1-month average impacts and 3-hour average used to conservatively represent 4-hour average impact.**

7.2 Associated Growth

The proposed project will employ approximately 200 personnel during the construction phase. The project will employ approximately 10 personnel on a permanent basis. It is a goal of the project to hire from the local community when possible. There should be no substantial increase in community growth, or need for additional infrastructure. It is not anticipated that the proposed action will result in an increase in secondary emissions associated with non-project related activities. Therefore, in accordance with PSD guidelines, the analysis of ambient air quality impacts need consider only emissions from the facility itself.

7.3 Class I Area Impact Analysis

The nearest PSD Class I area to the proposed facility is the Everglades National Park located about 180 kilometers to the southwest. Given that the Class I area is greater than 50 kilometers from the proposed facility, long range transport modeling involving the use of the CALPUFF dispersion model is required for the Class I impact assessment. The analysis will evaluate the potential impact of the proposed facility emissions in terms of air quality, regional haze, and deposition (sulfur and nitrogen). A separate analysis is being completed for this assessment in coordination with the National Park Service Air Quality Division. The results of the PSD Class I area assessment will be submitted as a supplement to this permit application.

APPENDIX A

FLORIDA DEP APPLICATION FORMS

Department of
Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Midway Development Company, L.L.C.**	
2. Site Name: **Midway Energy Center**	
3. Facility Identification Number: [✔] Unknown	
4. Facility Location: Street Address or Other Locator: **Northwest of the intersection of I-95 and W. Midway Rd** City: **Near Port St. Lucie** County: **St. Lucie** Zip Code: **34945**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [ ] Yes [✔] No

Application Contact

1. Name and Title of Application Contact: **Dave Kellermeyer, Director**
2. Application Contact Mailing Address: Organization/Firm: **Midway Development Company, L.L.C.** Street Address: **1400 Smith Street** City: **Houston** State: **TX** Zip Code: **77002-7631**
3. Application Contact Telephone Numbers: Telephone: (713) **853-3161** Fax: (713) **646-3037**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	11-9-00
2. Permit Number:	1110099-002-AC
3. PSD Number (if applicable):	PSD-FL-305
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:________________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:________________________

Operation permit number to be revised:________________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:________________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:________________________

Reason for revision:________________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[✔] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Ben Jacoby – Director**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Midway Development Company, L.L.C.** Street Address: **1400 Smith Street** City: **Houston** State: **TX** Zip Code: **77002-7631**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(713) 853-6173** Fax: **(713) 646-3037**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✔], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* Ben Jacoby 11-7-00 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Blair Burgess** Registration Number: **45460**
2.	Professional Engineer Mailing Address: Organization/Firm: **ENSR** Street Address: **2809 West Mall Drive** City: **Florence** State: **AL** Zip Code: **35630**
3.	Professional Engineer Telephone Numbers: Telephone: **(256) 767-1210** Fax: **(256) 767-1211**

4. Professional Engineer Statement:

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

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

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

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

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

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

Signature　　　　　　　　　　　　　　　　　　Date 11/2/00

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
CT001 – CT003	PG7241S(FA) Simple Cycle Combustion Turbines (Three identical combustion turbines)	AC1A	$7,500 Similar emissions unit fee per Rule 62-4.050(4)(a)(4)
T001 – T002	Distillate Fuel Oil Storage Tanks (Main Tank and Day Tank)	AC1F	
NGH	Natural Gas Fuel Heater	ACIF	

Application Processing Fee

Check one: [] Attached - Amount: [✔] Not Applicable

Note: Due to previously-submitted and withdrawn permit applications, the parent company of Midway Energy Center has an existing positive application fee balance with the Florida Department of Environmental Protection.

Construction/Modification Information

1. Description of Proposed Project or Alterations
Midway Development Company, L.L.C. proposes to construct and operate a peaking electrical power generating facility at a greenfield site in St. Lucie County, Florida. The facility will consist of three (3) GE PG7241S(FA) (GE 7FA) combustion turbines operating in simple cycle mode; each turbine has a nominal generating capacity of 170 MW at ISO base rating. The combustion turbines will be fired up to 1,500 hours on low sulfur distillate oil, the remaining operation on natural gas, for a total of up to 3,500 hours. Ancillary equipment includes one 2.5 million gallon distillate oil main storage tank, one 617,400 gallon distillate oil day storage tank and one 13 MMBtu/hr natural gas fuel heater.
2. Projected or Actual Date of Commencement of Construction: **April 1, 2001**
3. Projected Date of Completion of Construction: **May 1, 2002**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **556.7**		North (km): **3,028.5**
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Dave Kellermeyer, Director**		
2. Facility Contact Mailing Address: Organization/Firm: **Midway Development Company, L.L.C.** Street Address: **1400 Smith Street** City: **Houston**	State: **TX**	Zip Code: **77002-7631**
3. Facility Contact Telephone Numbers: Telephone: (713) **853-3161**	Fax: (713) **646-3037**	

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations (Facility-wide)

Chapter 62-4	**Permits**
Rule 62-204.220	**Ambient Air Quality Protection**
Rule 62-204.240	**Ambient Air Quality Standards**
Rule 62-204.260	**Prevention of Significant Deterioration Increments**
Rule 62-204.800	**Federal Regulations Adopted by Reference**
Rule 62-210.300	**Permits Required**
Rule 62-210.350	**Public Notice and Comments**
Rule 62-210.370	**Reports**
Rule 62-210.550	**Stack Height Policy**
Rule 62-210.650	**Circumvention**
Rule 62-210.700	**Excess Emissions**
Rule 62-210.900	**Forms and Instructions**
Rule 62-212.300	**General Preconstruction Review Requirements**
Rule 62-212.400	**Prevention of Significant Deterioration**
Rule 62-213	**Operation Permits for Major Sources of Air Pollution**
Rule 62-214	**Requirements for Sources Subject to the Federal Acid Rain Program**
Rule 62-296.	**General Pollutant Emission Limiting Standards**
Rule 62-297.310	**General Test Requirements**
Rule 62-297.401	**Compliance Test Methods**
Rule 62-297.520	**EPA Continuous Monitor Performance Specifications**
40 CFR 60	**Applicable sections of Subpart A, General Requirements, NSPS Subparts GG and Kb**
40 CFR 72	**Acid Rain Permits**
40 CFR 75	**Monitoring**
40 CFR 77	**Acid Rain Program – Excess Emissions**

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**				
CO	**A**				
SO2	**A**				
VOC	**B**				**Units T001 and T002 subject to record keeping requirements of 40 CFR 60, Subpart Kb**
PM	**A**				
PM10	**A**				
PB	**B**				
H114	**B**				
SAM	**B**				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [✔] Attached, Document ID: **Fig. 1-1** [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [✔] Attached, Document ID: **Fig. 1-2** [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [✔] Attached, Document ID: **Fig. 2-1** [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [✔] Attached, Document ID: **ENSR Document No. 6792-140-300** [ ] Not Applicable
7. Supplemental Requirements Comment: **See PSD BACT analysis in Section 5, air quality modeling results in Section 6, and additional impacts analysis in Section 7. Class I area analysis will be submitted as a supplement to the application at a later date.**

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [✔] Attached, Document ID: **Section 2** [ ] Not Applicable **A qualifying insignificant emission units based on PTE is the fuel gas heater. See Appendix B for supporting emission calculations.**
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [✔] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [✔] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [✔] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [✔] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [✔] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [✔] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [✔] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[✔] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[✔] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[ ] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
CT001 through CT003 are identical GE PG7241S(FA) (GE 7FA) simple cycle combustion turbines (CT) each having a nominal rating 170 megawatts (MW) at base load ISO conditions. Each CT will be fired with natural gas or low sulfur distillate oil.

4. Emissions Unit Identification Number: [✔] No ID
ID: **CT001; CT002; CT003** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**May 2002**	**49**	[✔]

9. Emissions Unit Comment: (Limit to 500 Characters)
Each combustion turbine (CT001, CT002, CT003) should be considered separate emissions units. The grouping of all turbines into one Emissions Unit Information Section has been done for administrative convenience since the information required in Subsections A through J is identical for each combustion turbine.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **NOx is limited through use of dry low NOx combustors for natural gas firing and water injection for distillate oil firing. See BACT analysis in Section 5.**	
2. Control Device or Method Code(s): **024**	

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **PG7241S(FA)**
2. Generator Nameplate Rating:	**170** MW **(nominal @ base load ISO)**
3. Incinerator Information: **N/A**	
Dwell Temperature:	°F
Dwell Time:	seconds
Incinerator Afterburner Temperature:	°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate: **2027 MMBtu** hr **HHV (base load on fuel oil @ 30°F)**				
2. Maximum Incineration Rate:	**N/A** lb/hr		**N/A** tons/day	
3. Maximum Process or Throughput Rate: **N/A**				
4. Maximum Production Rate: **N/A**				
5. Requested Maximum Operating Schedule:				
	24 hours/day		**7** days/week	
	52 weeks/year		**3500**[1] hours/year	
6. Operating Capacity/Schedule Comment (limit to 200 characters): **1 – Annual operations are based on a total of 3,500 hours per year per unit of which 1,500 hours per year per unit may be distillate fuel oil.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A (General Provisions for New Source Performance Standards)	
40 CFR 60.332(a)(1) – NO_x standards for Stationary Gas Turbines	
40 CFR 60.333 – SO_2 standards for Stationary Gas Turbines	
40 CFR 60.334 – Monitoring Provisions for Stationary Gas Turbines	
40 CFR Part 72 – Acid Rain Program Requirements Regulations	
40 CFR Part 73 – Acid Rain Program SO_2 Allowances System	
40 CFR Part 75 – Acid Rain Program Continuous Emissions Monitoring	
Rule 62-296.320(4)(b)1 – Visible emissions	
40 CFR 52.21 – Prevention of Significant Deterioration	
Rule 62-212.400 – Prevention of Significant Deterioration	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CT001, CT002, CT003**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhaust stacks for combustion turbines; one stack per turbine unit.**

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**

5. Discharge Type Code: **V**	6. Stack Height: **80** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1109°F (NG)** **1088°F (Oil)**	9. Actual Volumetric Flow Rate: **2,451,600 acfm (NG)** **2,519,400 acfm (Oil)**	10. Water Vapor: **8.54 % (NG)** **11.05 % (Oil)**

11. Maximum Dry Standard Flow Rate: **754,000 dscfm (NG)** **764,000 dscfm (Oil)**	12. Nonstack Emission Point Height: **N/A** feet

13. Emission Point UTM Coordinates:

Zone: 17 CT001: East (km): 556.670 North (km): 3,028.584
CT002: East (km): 556.670 North (km): 3,028.548
CT003: East (km): 556.670 North (km): 3,028.511

14. Emission Point Comment (limit to 200 characters):

Exhaust temperatures and flow rates (items 8, 9, 10, 11) are at 100% load and 50° F operating conditions. It is expected that the proposed turbines will operate using inlet air chilling during summer peaking operations and as such the inlet air temperature will effectively be at 50° F during the majority of operating hours. Stack temperatures and flow rates will vary with load and ambient temperature.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1___ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural gas**		
1. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
6. Maximum Hourly Rate: **1.912 (per turbine)**	7. Maximum Annual Rate: **6,691 (per turbine)**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **2 grains/100 SCF**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **978 (HHV)**
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate is based on the hourly fuel consumption rate at base load, 50°F for 3500 hours per year.**		

Segment Description and Rate: Segment __2___ of __2___

2. Segment Description (Process/Fuel Type) (limit to 500 characters): **No. 2 Distillate Fuel Oil**		
3. Source Classification Code (SCC): **2-01-001-0**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **14.6 (per turbine)**	5. Maximum Annual Rate: **21,876 (per turbine)**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **Trace**	9. Million Btu per SCC Unit: **139 (HHV)**
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate is based on the hourly fuel consumption rate at base load and 50° F for 1500 hours per year.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	**024 (GE DLN on gas)/028 (oil firing)**		**EL**
CO	**0**		**EL**
PM	**0**		**EL**
PM10	**0**		**EL**
SO2	**0**		**EL**
VOC	**0**		**EL**
PB	**0**		**EL**
SAM	**0**		**EL**
H114	**0**		**EL**
EL-Annual emissions potential to emit is based on operating 3,500 hours per year at full load, with 1,500 hours on oil.			

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **332.1** lb/hour **(per turbine)** **320** tons/year **(per turbine)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **12 ppmvd @15%$_{O2}$ on gas** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual NOx emissions based on 2000 hours on gas and 1500 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **9 to 12 ppmvd@15%O2 on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **82.1** lb/hour **320** tons/year
5. Method of Compliance (limit to 60 characters): **Compliance with 9 ppm limit during initial and annual performance stack tests using EPA Method 20. Compliance with 12 ppm limit shall be with CEM on a 24-hour block average.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2____ of ___2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **42 ppmvd@15% O_2 on oil for 1500 of 3500 hours (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **332.1** lb/hour **320** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests with EPA Method 20. Continuous compliance based on CEM 3-hour average.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **78.3** lb/hour **(per turbine)** **238.8** tons/year **(per turbine)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **9 ppmvd @15% O_2 on gas** **30 ppmvd @15% O_2 on oil** Reference: **See Appendix B for emission calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperatures. Annual CO emissions based on 2000 hours on gas and 1500 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **9 ppmvd @ 15% O_2 on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **30.9** lb/hour **79.6** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests using EPA Method 10.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2___ of __2____

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **30 ppmdv @15% O_2 on oil (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **78.3** lb/hour **79.6** tons/year
5. Method of Compliance (limit to 60 characters): **Initial and annual performance stack tests using EPA Method 10.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: 34.0 lb/hour**(per turbine)** 43.5 tons/year **(per turbine)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.003 lb/MMBtu on oil** **0.017 lb/MMBtu on gas** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual PM/PM10 emissions based on 2000 hours on gas and 1500 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **18 lb/hr on gas (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: 18 lb/hour 43.5 tons/year
5. Method of Compliance (limit to 60 characters): **Visible emissions testing as a surrogate for PM compliance testing.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2___ of __2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **34 lb/hr on oil (CT001, CT002, CT003)**	4. Equivalent Allowable Emissions: **34** lb/hour **43.5** tons/year
5. Method of Compliance (limit to 60 characters): **Visible emissions testing as a surrogate for PM compliance testing.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **103.6** lb/hour **(per turbine)** **85.8** tons/year **(per turbines)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
7. Emission Factor: **0.02 gr S / SCF nat. gas.** **0.05% S in oil.** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual SO_2 emissions based on 2000 hours on gas and 1500 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ___1___ of ___2___

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **10.9 lb/hr on gas (CT001, CT002, CT003) Sulfur content 2 gr/100 dscf**	4. Equivalent Allowable Emissions: **10.9** lb/hour **85.8** tons/year
5. Method of Compliance (limit to 60 characters): **Use of pipeline natural gas and custom fuel monitoring schedule.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
2. Requested Allowable Emissions and Units: **103.6 lb/hr on oil; 0.05% S content fuel**	4. Equivalent Allowable Emissions: **103.6** lb/hour **85.8** tons/year
5. Method of Compliance (limit to 60 characters): **Use of low sulfur distillate fuel oil.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.1** lb/hour **(per turbine)** **5.2** tons/year **(per turbine)**	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.4 ppmvw** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate is based on worst case vendor emission rate for both natural gas and distillate oil for the expected ranges of operating loads and ambient temperature. Annual VOC emissions based on 2000 hours on gas and 1500 hours on distillate oil at base load, 50° F.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __2__ N/A

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Requested Allowable Emissions and Units: **3.0 lb/hr on natural gas**	4. Equivalent Allowable Emissions: **3.0** lb/hour **5.2** tons/year
5. Method of Compliance (limit to 60 characters): **Initial Stack Test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Allowable Emissions Allowable Emissions ___2__ of ___2__

2. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: N/A
4. Requested Allowable Emissions and Units: **3.1 lb/hr on fuel oil**	4. Equivalent Allowable Emissions: **3.1** lb/hour **5.2** tons/year
5. Method of Compliance (limit to 60 characters): **Initial stack test using Method 18, 25 or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Applicant requests limit in accordance with BACT analysis presented in Section 5.0 per FDEP Rule 62-212.400.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions

1. Pollutant Emitted: **Pb**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.028** lb/hour **(per turbine)** **0.02** tons/year **(per turbine)**	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.000014 lb/MMBtu** Reference: **See Appendix B for emissions calculations**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Emission factor is for worst case, firing on distillate oil. No Pb is expected from natural gas combustion.**	

Allowable Emissions Allowable Emissions ______ of _____N/A_

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **15.9** lb/hour **(per turbine)** **13.1** tons/year **(per turbine)**	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.009 lb/MMBtu on oil** Reference: **See Appendix B for emissions calculations.**	8. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **SAM is not expected to be generated prior to leaving the stack, due to the high temperatures. However, precursor to SAM (SO3) is generated.**	

Allowable Emissions Allowable Emissions ______ of ______**N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **H114**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.47 E-3** lb/hour **9.60 E-4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 1.2 E-6 lb/MMBtu Reference: **See Appendix B for emissions calculations.**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission factor for mercury (Hg) is for worst case, firing on distillate oil. No Hg is expected from natural gas combustion.**	

Allowable Emissions Allowable Emissions ______ of ______**N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of ___1___

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [✔] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9.**	
5. Visible Emissions Comment (limit to 200 characters): **The general visible emission standard requirements of Rule 62-296.320(4)(b)1, F.A.C. apply to each turbine stack.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor __1___ of __1___

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule (NOX) [ ] Other
4. Monitor Information: **TBD** Manufacturer: **TBD** Model Number: **TBD**	Serial Number: **TBD**
5. Installation Date: **Prior to start up**	6. Performance Specification Test Date: **90 days after unit commences commercial operation in accordance with 40 CFR 75.4(b)(2).**
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID:**Fig. 2-2** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID:**App. B** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [✔] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [✔] Attached, Document ID: **ENSR Doc. No. 6792-140-300**
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [✔] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [✔] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [✔] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [✔] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [✔] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: **To be supplied at a later date** [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

III. TANK EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in This Section: (Check one)

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

[✔] This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

[ ] This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Regulated or Unregulated Emissions Unit? (Check one)

[ ] The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

[✔] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Distillate fuel oil storage tanks

4. Emissions Unit Identification Number:
ID: **T001, T002**

[✔] No ID
[ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**May 2002**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

T001 – main storage tank
T002 – day storage tank.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **None**
2. Control Device or Method Code(s):

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating:	MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate: **N/A** mmBtu/hr		
2. Maximum Incineration Rate: **N/A** lb/hr		**N/A** tons/day
3. Maximum Process or Throughput Rate: **65,700,000 gal/year**		
4. Maximum Production Rate: **N/A**		
5. Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **8760** hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Peak demand anticipated June – August; December – February** **T001 – 2.5 MM gallon capacity** **T002 – 617,400 gallon capacity**		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A (General Provisions for New Source Performance Standards)	
40 CFR 60.116b(a) and (b) – Record Keeping requirements under Subpart Kb	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **T001, T002**		2. Emission Point Type Code: **4**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **N/A** feet	7. Exit Diameter: **N/A** feet
8. Exit Temperature: **N/A**	9. Actual Volumetric Flow Rate: **N/A**	10. Water Vapor: **N/A**
11. Maximum Dry Standard Flow Rate: **N/A** dscfm		12. Nonstack Emission Point Height: **N/A** feet
13. Emission Point UTM Coordinates: **Main tank: Zone 17; 556.763 East (km) 3,028.437 North (km)** **Day tank: Zone 17; 556.803 East (km) 3,028.435 North (km)**		
14. Emission Point Comment (limit to 200 characters):		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate fuel oil storage tanks**		
2. Source Classification Code (SCC): **40301021**	3. SCC Units: **Thousand Gallons Throughput**	
4. Maximum Hourly Rate: **N/A**	5. Maximum Annual Rate: **65,700**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ___ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			NS

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Potential VOC emissions from distillate fuel oil storage tanks are less than 5 tons per year (less than the threshold amount for reporting in this subsection). See Appendix B for emission calculations.**	

Allowable Emissions Allowable Emissions **1** of **1** **N/A**

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: **N/A**

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: N/A

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule (**NOX**) [ ] Other (**CO**)
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID: [✔] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID: [✔] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [✔] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [✔] Attached, Document ID: **See calculations in Appendix B for tank information.**
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [✔] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:________ [✔] Not Applicable

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:________ [✔] Not Applicable

14. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:________ [✔] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

[ ] Acid Rain Part – Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:________

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:________

[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:________

[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
Attached, Document ID:________

[✔] Not Applicable

APPENDIX B

EMISSION CALCULATIONS

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Natural Gas Only					Proposed Design Specification
Fuel Heating Value		(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content		(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	151000	174800	178000	182200		
Heat Input Rate		(MMBtu/Hr, LHV)	1,464.7	1,629.1	1,652.7	1,684.4		Manufacturer Supplied Data
Fuel Feed Rate		*(SCF/Hr)*	1,662,354	1,848,939	1,875,724	1,911,701		*Calculated*
Exhaust Temperature		(F)	1,149	1,109	1,100	1,087		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	150.4	160.6	162.0	164.0		Calculated
Exhaust Analysis	Argon		0.87	0.90	0.90	0.90		39.948 lb/lb mol Ar
	Nitrogen		72.83	74.32	74.55	74.94		28.0134 lb/lb mol N_2
	Oxygen		12.22	12.50	12.57	12.68		31.998 lb/lb mol O_2
	Carbon Dioxide		3.69	3.75	3.74	3.74		44.009 lb/lb mol CO_2
	Water		10.40	8.54	8.25	7.75		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.16	28.37	28.40	28.45		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	3,301,000	3,642,000	3,700,000	3,783,000		Manufacturer Supplied Data
		(ACFHW)	137,744,689	147,096,451	148,423,690	150,200,713		Calculated
		(ACFMW)	2,295,745	2,451,608	2,473,728	2,503,345		Calculated
		(ACFHD)	123,419,241	134,534,414	136,178,735	138,560,158		Calculated
		(ACFMD)	2,056,987	2,242,240	2,269,646	2,309,336		Calculated
		(SCFHW)	45,182,505	49,480,378	50,214,935	51,243,258		Calculated
		(SCFMW)	753,042	824,673	836,916	854,054		Calculated
		(SCFHD)	40,483,524	45,254,754	46,072,203	47,271,906		Calculated
		(SCFMD)	674,725	754,246	767,870	787,865		Calculated
Exhaust Moisture		(%)	10.40	8.54	8.25	7.75		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	13.64	13.67	13.70	13.75		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	12	12	12	12		Manufacturer Supplied Data
		(ppmvd)	14.8	14.7	14.6	14.6		Calculated
Concentration of CO in Exhaust		(ppmvd)	9	9	9	9		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	7.3	7.3	7.4	7.4		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.5	1.5	1.5		Calculated
		(ppmvd @ 15% O2)	1.3	1.2	1.3	1.3		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine		
Project Number:	6792-140	Computed by: M. Lafond	Date: 9/24/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions	Checked by: M. Griffin	Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{(\text{NOx Concentration, ppmvd}) * (\text{Exhaust Flow Rate, SCFMD}) * (\text{Mol Wt. NOx, Lbs/Lb-Mol}) * 60\ \text{Min/Hr}}{(385\ \text{SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr=	71.4	79.5	80.5	82.1	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{(\text{CO Concentration, ppmvd}) * (\text{Exhaust Flow Rate, SCFMD}) * (\text{Mol Wt. CO, Lbs/Lb-Mol}) * 60\ \text{Min/Hr}}{(385\ \text{SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	26.5	29.6	30.1	30.9	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{(\text{VOC Concentration as Methane, ppmvw}) * (\text{Exhaust Flow Rate, SCFMW}) * (\text{Mol Wt. VOC, Lbs/Lb-Mol}) * 60\ \text{Min/Hr}}{(385\ \text{SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.6	2.9	2.9	3.0	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

SULFUR DIOXIDE

$$\text{Lbs/Hr} = \frac{(\text{Expected Fuel Gas Sulfur Content, Grains/SCF}) * (\text{Fuel Feed Rate, SCF/Hr}) * (64 \text{ Lbs } SO_2/32 \text{ Lbs S})}{(7{,}000 \text{ Grains/Lbs})}$$

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	9.5	10.6	10.7	10.9	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

$$\text{Lbs/Hr} = (SO_2 \text{ Emission Rate, lb/hr}) * (SO_2 \text{ to } SO_3 \text{ Conversion Rate, lb/Hr}) * (98.07 \text{ Lbs } SO_2/64.062 \text{ Lbs S})$$

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.5	1.6	1.6	1.7	

Note:
Assume 10% conversion of SO_2 to SO_3. Assume all SO_3 is converted to H_2SO_4.

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Natural Gas Only					Proposed Design Specification
Fuel Heating Value	(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content	(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	113300	131100	133500	136700		
Heat Input Rate	(MMBtu/Hr, LHV)	1,202.1	1,312.3	1,328.3	1,353.3		Manufacturer Supplied Data
Fuel Feed Rate	(SCF/Hr)	1,364,317	1,489,388	1,507,547	1,535,921		Calculated
Exhaust Temperature	(F)	1,180	1,147	1,142	1,134		Manufacturer Supplied Data
Exhaust Velocity	(F/S)	125.8	130.8	131.5	132.7		Calculated
Exhaust Analysis Argon		0.87	0.89	0.89	0.89		39.948 lb/lb mol Ar
Nitrogen		72.86	74.31	74.53	74.90		28.0134 lb/lb mol N_2
Oxygen		12.30	12.48	12.51	12.58		31.998 lb/lb mol O_2
Carbon Dioxide		3.65	3.76	3.77	3.79		44.009 lb/lb mol CO_2
Water		10.32	8.56	8.30	7.84		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.16	28.36	28.39	28.44		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,710,000	2,897,000	2,923,000	2,970,000		Manufacturer Supplied Data
	(ACFHW)	115,254,389	119,863,053	120,440,174	121,542,995		Calculated
	(ACFMW)	1,920,906	1,997,718	2,007,336	2,025,717		Calculated
	(ACFHD)	103,360,136	109,602,775	110,443,639	112,014,025		Calculated
	(ACFMD)	1,722,669	1,826,713	1,840,727	1,866,900		Calculated
	(SCFHW)	37,090,563	39,365,979	39,679,002	40,243,333		Calculated
	(SCFMW)	618,176	656,100	661,317	670,722		Calculated
	(SCFHD)	33,262,817	35,996,251	36,385,644	37,088,256		Calculated
	(SCFMD)	554,380	599,938	606,427	618,138		Calculated
Exhaust Moisture	(%)	10.32	8.56	8.30	7.84		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	13.72	13.65	13.64	13.65		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	12	12	12	12		Manufacturer Supplied Data
	(ppmvd)	14.6	14.7	14.8	14.7		Calculated
Concentration of CO in Exhaust	(ppmvd)	9	9	9	9		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	7.4	7.3	7.3	7.3		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.5	1.5	1.5		Calculated
	(ppmvd @ 15% O2)	1.3	1.2	1.2	1.2		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 — Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions — Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	58.0	63.4	64.1	65.3	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	21.8	23.5	23.8	24.3	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) * (Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.2	2.3	2.3	2.3	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

$$\text{Lbs/Hr} = \frac{\text{(Expected Fuel Gas Sulfur Content, Grains/SCF) * (Fuel Feed Rate, SCF/Hr) * (64 Lbs SO2/32 Lbs S)}}{\text{(7,000 Grains/Lbs)}}$$

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	7.8	8.5	8.6	8.8	

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.2	1.3	1.3	1.3	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

Notes:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Natural Gas Only					Proposed Design Specification
Fuel Heating Value	(Btu/SCF, LHV)	881.1					Manufacturer Supplied Data
Fuel Sulfur Content	(Grains/SCF)	0.02					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	75500	87400	89000	91100		
Heat Input Rate	(MMBtu/Hr, LHV)	961.1	1,052.3	1,063.6	1,079.5		Manufacturer Supplied Data
Fuel Feed Rate	(SCF/Hr)	1,090,796	1,194,303	1,207,127	1,225,173		Calculated
Exhaust Temperature	(F)	1,200	1,194	1,189	1,182		Manufacturer Supplied Data
Exhaust Velocity	(F/S)	106.9	111.3	111.8	112.4		Calculated
Exhaust Analysis Argon		0.88	0.88	0.89	0.90		39.948 lb/lb mol Ar
Nitrogen		73.02	74.43	74.64	75.02		28.0134 lb/lb mol N_2
Oxygen		12.76	12.81	12.84	12.90		31.998 lb/lb mol O_2
Carbon Dioxide		3.44	3.61	3.62	3.64		44.009 lb/lb mol CO_2
Water		9.91	8.27	8.01	7.55		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.19	28.38	28.41	28.46		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,278,000	2,396,000	2,416,000	2,444,000		Manufacturer Supplied Data
	(ACFHW)	97,960,041	101,973,241	102,405,341	102,950,915		Calculated
	(ACFMW)	1,632,667	1,699,554	1,706,756	1,715,849		Calculated
	(ACFHD)	88,252,201	93,540,054	94,202,673	95,178,121		Calculated
	(ACFMD)	1,470,870	1,559,001	1,570,045	1,586,302		Calculated
	(SCFHW)	31,145,092	32,538,669	32,775,647	33,090,761		Calculated
	(SCFMW)	519,085	542,311	546,261	551,513		Calculated
	(SCFHD)	28,058,613	29,847,721	30,150,318	30,592,408		Calculated
	(SCFMD)	467,644	497,462	502,505	509,873		Calculated
Exhaust Moisture	(%)	9.91	8.27	8.01	7.55		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	14.16	13.96	13.96	13.95		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	12	12	12	12		Manufacturer Supplied Data
	(ppmvd)	13.7	14.1	14.1	14.1		Calculated
Concentration of CO in Exhaust	(ppmvd)	9	9	9	9		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	7.9	7.7	7.6	7.6		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.5	1.5	1.5		Calculated
	(ppmvd @ 15% O2)	1.4	1.3	1.3	1.3		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Date: 9/25/00
Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. NOx, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	45.9	50.3	50.8	51.6	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd) * (Exhaust Flow Rate, SCFMD) * (Mol Wt. CO, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18.4	19.5	19.7	20.0	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw) * (Exhaust Flow Rate, SCFMW) * (Mol Wt. VOC, Lbs/Lb-Mol) * 60 Min/Hr}}{\text{(385 SCF/Lb-Mol) * (1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.8	1.9	1.9	1.9	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

$$\text{Lbs/Hr} = \frac{\text{(Expected Fuel Gas Sulfur Content, Grains/SCF) * (Fuel Feed Rate, SCF/Hr) * (64 Lbs SO2/32 Lbs S)}}{\text{(7,000 Grains/Lbs)}}$$

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	6.2	6.8	6.9	7.0	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

$$\text{Lbs/Hr} = \text{(SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)}$$

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.9	1.0	1.1	1.1	

Note:
Assume 10% conversion of SO_2 to SO_3. Assume all SO_3 is converted to H_2SO_4.

PARTICULATE MATTER

Base Equations

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	18	18	18	18	

Notes:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters		Units	Design Data				Proposed Permit Limit	Comments
Turbine Load		(%)	100					Manufacturer Supplied Data
Stack Diameter		(Feet)	18					Proposed Design Specification
Fuel Type			Distillate Oil					Proposed Design Specification
Fuel Heating Value		(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content		(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature		(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity		(%)						Manufacturer Supplied Data
CTG - Gross Power Output		(kW)	160,800.00	182500	185,400.00	189300		
Heat Input Rate		(MMBtu/Hr, LHV)	1,645.0	1,825.0	1,851.2	1,887.3		Manufacturer Supplied Data
Fuel Feed Rate		(lb/Hr)	90,385	100,275	101,714	103,698		Calculated
Exhaust Temperature		(F)	1,138	1,088	1,079	1,065		Manufacturer Supplied Data
Exhaust Velocity		(F/S)	154.4	165.0	166.5	168.6		Calculated
Exhaust Analysis	Argon		0.85	0.85	0.85	0.87		39.948 lb/lb mol Ar
	Nitrogen		70.33	71.37	71.56	71.86		28.0134 lb/lb mol N_2
	Oxygen		11.02	11.26	11.32	11.41		31.998 lb/lb mol O_2
	Carbon Dioxide		5.44	5.47	5.46	5.45		44.009 lb/lb mol CO_2
	Water		12.37	11.05	10.81	10.42		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight		(Lbs/Lb-Mol)	28.19	28.33	28.36	28.40		Calculated
Exhaust Flow Rate		(Lbs/Hr, Wet)	3,417,000	3,789,000	3,850,000	3,939,000		Manufacturer Supplied Data
		(ACFHW)	141,445,658	151,166,218	152,573,185	154,428,463		Calculated
		(ACFMW)	2,357,428	2,519,437	2,542,886	2,573,808		Calculated
		(ACFHD)	123,948,830	134,462,350	136,080,024	138,337,017		Calculated
		(ACFMD)	2,065,814	2,241,039	2,268,000	2,305,617		Calculated
		(SCFHW)	46,715,924	51,539,332	52,323,300	53,445,839		Calculated
		(SCFMW)	778,599	858,989	872,055	890,764		Calculated
		(SCFHD)	40,937,164	45,844,236	46,667,152	47,876,782		Calculated
		(SCFMD)	682,286	764,071	777,786	797,946		Calculated
Exhaust Moisture		(%)	12.37	11.05	10.81	10.42		Manufacturer Supplied Data
Exhaust O2 Dry		(%)	12.58	12.66	12.69	12.74		Calculated
Concentration of NOx in Exhaust		(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
		(ppmvd)	59.3	58.7	58.4	58.1		Calculated
Concentration of CO in Exhaust		(ppmvd)	20	20	20	20		Manufacturer Supplied Data
		(ppmvd @ 15% O2)	14.2	14.3	14.4	14.5		Calculated
Concentration of VOC in Exhaust		(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
		(ppmvd)	1.6	1.6	1.6	1.6		Calculated
		(ppmvd @ 15% O2)	1.1	1.1	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd)} \cdot \text{(Exhaust Flow Rate, SCFMD)} \cdot \text{(Mol Wt. NOx, Lbs/Lb-Mol)} \cdot \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} \cdot \text{(1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr=	289.6	321.0	325.5	332.1	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd)} \cdot \text{(Exhaust Flow Rate, SCFMD)} \cdot \text{(Mol Wt. CO, Lbs/Lb-Mol)} \cdot \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} \cdot \text{(1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	59.5	66.6	67.8	69.6	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw)} \cdot \text{(Exhaust Flow Rate, SCFMW)} \cdot \text{(Mol Wt. VOC, Lbs/Lb-Mol)} \cdot \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} \cdot \text{(1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.7	3.0	3.0	3.1	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	90.3	100.2	101.6	103.6	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	13.8	15.3	15.6	15.9	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 100 % Load Conditions

Computed by: M. Lafond Date: 9/24/00
Checked by: M. Griffin Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.025	0.027	0.028	0.028	

Note:
Use AP-42 Section 3.1 Emission Factor. 0.000014 lb/MMBtu

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Distillate Oil					Proposed Design Specification
Fuel Heating Value	(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content	(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	120,600	136,900	139,000	142,000		
Heat Input Rate	(MMBtu/Hr, LHV)	1,336.2	1,458.0	1,480.4	1,510.9		Manufacturer Supplied Data
Fuel Feed Rate	(lb/Hr)	73,418	80,110	81,341	83,016		Calculated
Exhaust Temperature	(F)	1,186	1,153	1,148	1,142		Manufacturer Supplied Data
Exhaust Velocity	*(F/S)*	*128.3*	*133.0*	*134.0*	*135.5*		*Calculated*
Exhaust Analysis Argon		0.85	0.85	0.86	0.86		39.948 lb/lb mol Ar
Nitrogen		70.71	71.57	71.69	71.90		28.0134 lb/lb mol N_2
Oxygen		11.15	11.13	11.13	11.14		31.998 lb/lb mol O_2
Carbon Dioxide		5.42	5.60	5.62	5.65		44.009 lb/lb mol CO_2
Water		11.88	10.86	10.71	10.45		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.24	28.37	28.39	28.42		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,761,000	2,934,000	2,968,000	3,015,000		Manufacturer Supplied Data
	(ACFHW)	117,511,976	121,810,383	122,756,013	124,110,414		Calculated
	(ACFMW)	1,958,533	2,030,173	2,045,934	2,068,507		Calculated
	(ACFHD)	103,551,553	108,581,776	109,608,844	111,140,876		Calculated
	(ACFMD)	1,725,859	1,809,696	1,826,814	1,852,348		Calculated
	(SCFHW)	37,679,209	39,856,688	40,291,021	40,888,162		Calculated
	(SCFMW)	627,987	664,278	671,517	681,469		Calculated
	(SCFHD)	33,202,919	35,528,252	35,975,853	36,615,349		Calculated
	(SCFMD)	553,382	592,138	599,598	610,256		Calculated
Exhaust Moisture	(%)	11.88	10.86	10.71	10.45		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	12.65	12.49	12.47	12.44		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
	(ppmvd)	58.7	59.9	60.0	60.2		Calculated
Concentration of CO in Exhaust	(ppmvd)	21	22	22	22		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	15.0	15.4	15.4	15.3		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.6	1.6	1.6		Calculated
	(ppmvd @ 15% O2)	1.1	1.1	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine		
Project	Number: 6792-140	Computed by: M. Lafond	Date: 9/25/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions	Checked by: M. Griffin	Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{(\text{NOx Concentration, ppmvd}) * (\text{Exhaust Flow Rate, SCFMD}) * (\text{Mol Wt. NOx, Lbs/Lb-Mol}) * 60\ \text{Min/Hr}}{(385\ \text{SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	232.7	254.0	257.9	263.2	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{(\text{CO Concentration, ppmvd}) * (\text{Exhaust Flow Rate, SCFMD}) * (\text{Mol Wt. CO, Lbs/Lb-Mol}) * 60\ \text{Min/Hr}}{(385\ \text{SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	50.7	56.8	57.5	58.5	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{(\text{VOC Concentration as Methane, ppmvw}) * (\text{Exhaust Flow Rate, SCFMW}) * (\text{Mol Wt. VOC, Lbs/Lb-Mol}) * 60\ \text{Min/Hr}}{(385\ \text{SCF/Lb-Mol}) * (1{,}000{,}000)}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	2.2	2.3	2.3	2.4	

CALCULATIONS AND COMPUTATIONS

Project:	Florida GE 7FA Turbine			
Project	Number: 6792-140	Computed by: M. Lafond	Date:	9/25/00
Subject:	Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions	Checked by: M. Griffin	Date:	9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	73.3	80.0	81.3	82.9	

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	11.2	12.2	12.4	12.7	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 75 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

Notes:

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.020	0.022	0.022	0.023	

Note:
Use AP-42 Section 3.1 Emission Factor. 0.000014 lb/MMBtu

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

Design Parameters	Units	Design Data				Proposed Permit Limit	Comments
Turbine Load	(%)	100					Manufacturer Supplied Data
Stack Diameter	(Feet)	18					Proposed Design Specification
Fuel Type		Distillate Oil					Proposed Design Specification
Fuel Heating Value	(Btu/lb, LHV)	18200					Manufacturer Supplied Data
Fuel Sulfur Content	(wt % sulfur)	0.05%					Manufacturer Supplied Data
Ambient Temperature	(F)	91	50	42	30		Manufacturer Supplied Data
Relative Humidity	(%)						Manufacturer Supplied Data
CTG - Gross Power Output	(kW)	80,400.00	91300	92,700.00	94600		
Heat Input Rate	(MMBtu/Hr, LHV)	1,054.8	1,155.9	1,168.9	1,186.3		Manufacturer Supplied Data
Fuel Feed Rate	(lb/Hr)	57,956	63,511	64,225	65,181		Calculated
Exhaust Temperature	(F)	1,200	1,200	1,200	1,193		Manufacturer Supplied Data
Exhaust Velocity	(F/S)	109.0	112.5	112.9	113.4		Calculated
Exhaust Analysis Argon		0.86	0.86	0.85	0.86		39.948 lb/lb mol Ar
Nitrogen		71.45	72.18	72.29	72.53		28.0134 lb/lb mol N_2
Oxygen		11.91	11.67	11.63	11.64		31.998 lb/lb mol O_2
Carbon Dioxide		5.03	5.34	5.39	5.42		44.009 lb/lb mol CO_2
Water		10.75	9.95	9.84	9.55		18.0148 lb/lb mol H_2O
Exhaust Molecular Weight	(Lbs/Lb-Mol)	28.32	28.44	28.46	28.49		Calculated
Exhaust Flow Rate	(Lbs/Hr, Wet)	2,333,000	2,419,000	2,427,000	2,451,000		Manufacturer Supplied Data
	(ACFHW)	99,860,109	103,104,272	103,386,331	103,839,200		Calculated
	(ACFMW)	1,664,335	1,718,405	1,723,106	1,730,653		Calculated
	(ACFHD)	89,125,148	92,845,397	93,213,116	93,922,557		Calculated
	(ACFMD)	1,485,419	1,547,423	1,553,552	1,565,376		Calculated
	(SCFHW)	31,749,193	32,780,632	32,870,309	33,154,127		Calculated
	(SCFMW)	529,153	546,344	547,838	552,569		Calculated
	(SCFHD)	28,336,155	29,518,959	29,635,870	29,987,908		Calculated
	(SCFMD)	472,269	491,983	493,931	499,798		Calculated
Exhaust Moisture	(%)	10.75	9.95	9.84	9.55		Manufacturer Supplied Data
Exhaust O2 Dry	(%)	13.34	12.96	12.90	12.87		Calculated
Concentration of NOx in Exhaust	(ppmvd@15% O2)	42	42	42	42		Manufacturer Supplied Data
	(ppmvd)	53.8	56.5	57.0	57.2		Calculated
Concentration of CO in Exhaust	(ppmvd)	38	31	30	31		Manufacturer Supplied Data
	(ppmvd @ 15% O2)	29.7	23.0	22.1	22.8		Calculated
Concentration of VOC in Exhaust	(ppmvw)	1.4	1.4	1.4	1.4		Manufacturer Supplied Data
	(ppmvd)	1.6	1.6	1.6	1.5		Calculated
	(ppmvd @ 15% O2)	1.2	1.2	1.1	1.1		Calculated

Note:

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Date: 9/25/00
Date: 9/26/00

OXIDES OF NITROGEN

$$\text{Lbs/Hr} = \frac{\text{(NOx Concentration, ppmvd)} * \text{(Exhaust Flow Rate, SCFMD)} * \text{(Mol Wt. NOx, Lbs/Lb-Mol)} * \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} * \text{(1,000,000)}}$$

Oxides of Nitrogen Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	181.9	199.2	201.5	204.6	

CARBON MONOXIDE

$$\text{Lbs/Hr} = \frac{\text{(CO Concentration, ppmvd)} * \text{(Exhaust Flow Rate, SCFMD)} * \text{(Mol Wt. CO, Lbs/Lb-Mol)} * \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} * \text{(1,000,000)}}$$

Carbon Monoxide Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	78.3	66.5	64.6	67.6	

VOLATILE ORGANIC COMPOUNDS

$$\text{Lbs/Hr} = \frac{\text{(VOC Concentration as Methane, ppmvw)} * \text{(Exhaust Flow Rate, SCFMW)} * \text{(Mol Wt. VOC, Lbs/Lb-Mol)} * \text{60 Min/Hr}}{\text{(385 SCF/Lb-Mol)} * \text{(1,000,000)}}$$

Volatile Organic Compounds Emission Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	1.8	1.9	1.9	1.9	

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine
Project Number: 6792-140 Date: 9/25/00
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions Date: 9/26/00

SULFUR DIOXIDE

Lbs/Hr = (Expected Fuel Oil Sulfur Content, wt % Sulfur) * (Fuel Feed Rate, lb/Hr) * (64 Lbs SO2/32 Lbs S)

Sulfur Dioxide Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	57.9	63.4	64.2	65.1	

Note:
Sulfur emissions calculated based on Natural Gas sulfur content of 0.02 grains of sulfur/SCF Natural Gas

SULFURIC ACID MIST

Lbs/Hr = (SO2 Emission Rate, lb/hr) * (SO2 to SO3 Conversion Rate, lb/Hr) * (98.07 Lbs SO2/64.062 Lbs S)

Sulfuric Acid Mist Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	8.9	9.7	9.8	10.0	

Note:
Assume 10% conversion of SO2 to SO3. Assume all SO3 is converted to H2SO4.

CALCULATIONS AND COMPUTATIONS

Project: Florida GE 7FA Turbine

Project Number: 6792-140
Subject: Gas Turbine Emission Calculations - GE 7FA - 50 % Load Conditions

Computed by: M. Lafond Date: 9/25/00
Checked by: M. Griffin Date: 9/26/00

PARTICULATE MATTER

Particulate Matter Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	34	34	34	34	

Notes:

LEAD

Lbs/Hr = (Lead Emission Factor, lb/MMBtu) * (Fuel Feed Rate, MMBtu/Hr)

Lead Emissions Summary

Ambient Temperature	91	50	42	30	Proposed Permit Limit
	Emission Per Combustion Turbine Unit				
Lbs/Hr =	0.016	0.017	0.018	0.018	

Note:
Use AP-42 Section 3.1 Emission Factor. 0.000014 lb/MMBtu

ENRON - Florida
Estimated NSPS NO_x Emission Standard

Turbine General Electric Model 7FA Natural Gas Firing		
Nominal Maximum Electrical Capacity	174.8	MW
Maximum Energy Input	1629.1	MMBtu/hr (LHV)
	1,719,677,960	kJ/hr
Heat Rate	9,320	Btu/kWh
	9.8	kJ/Wh
NSPS Subpart GG NOx Limit	0.0110%	Volume % NOx @ 15% O2
	110	ppmvd @ 15% O2

Turbine General Electric Model 7FA Distillate Fuel Oil Firing		
Nominal Maximum Electrical Capacity	182.5	MW
Maximum Energy Input	1825	MMBtu/hr (LHV)
	1,926,470,000	kJ/hr
Heat Rate	10,000	Btu/kWh
	10.6	kJ/Wh
NSPS Subpart GG NOx Limit	0.0102%	Volume % NOx @ 15% O2
	102	ppmvd @ 15% O2

Note:

These calculations have been performed using nominal turbine data at 50 degrees F conditions and are intended to provide an estimate of 40 CFR 60 Subpart GG NOx Emission Limits.

CALCULATIONS AND COMPUTATIONS

Project	Florida GE 7FA Turbine				
Project Number:	6792-140	Computed by:	M. Lafond	Date:	9/25/00
Subject	Natural Gas Heater - Emission Calculations	Checked by:	M. Griffin	Date:	10/6/00

Emission Source:	Natural Gas Heater
Source Type:	Natural Gas Fueled Heater
Heat Input (MMBtu/hr):	13
Number of Units:	1
Sulfur Content of Fuel (grains/scf):	0.02
Fuel Heating Value, HHV (Btu/scf):	1020
LHV (Btu/scf):	908
Operating Hours per Year:	3500
Fuel Feed Rate (scf/HR):	12745

Compound	Emission Factor (a)	Emission Rate - per Unit	
		Hourly (b)	Annual (c)
	(Lbs/MMBtu)	(Lbs/Hr)	(Tons/Year)
Criteria Pollutants			
Nitrogen Oxides	0.102	1.3	2.3
Carbon Monoxide	0.09	1.2	2.1
Volatile Organic Carb	0.06	0.78	1.37
Sulfur Oxides (d)	0.01	0.07	0.13
Particulate	0.01	0.13	0.23

Notes:

(a) Emission Factors based on the information supplied by ENRON on 8/11/99.

(b) Hourly Emission Rate (Lbs/Hr) = (Heat Input * Emission Factor)

(c) Annual Emission Rate (Tons/Yr) = (Hourly Emission Rate, Lbs/Hr) * (Hour of Operation Per Year, Hr/Yr) / (2,000 Lbs/Ton)

(d) Sulfur Oxides Emission Rate (Lbs/Hr) based on the sulfur content of the fuel.

TANKS 4.07 Output and VOC Emissions Calculations for Enron - Florida
T001 No. 2 Oil Main Tank

TANKS Ouput:

Maximum Hourly Emission Rate:

July =	744	hours
July Max Fuel Use =	32,551,686	gallons/month
Greatest monthly total standing plus working loss - July	1338.29	lb/month
Maximum VOC emission rate =	1.80	lb/hr

Annual Total Emission Rate:

Annual total standing plus working losses =	2734.07	lb/year
PTE =	1.4	tons/yr

Tank Specifications Used:

Vertical fixed roof
Vented to atmosphere, default breather vent +/- 0.03 psig
Non-heated
Flat roof
Shell in good condition
65,700,000 gallons/year throughput
2,500,000 gallons capacity

26 turnovers/year Throughput/capacity)
Average liquid height in tank 1/2 tank height

TANKS 4.07 Output and VOC Emissions Calculations for Enron - Florida
T002 No. 2 Oil Day Tank

TANKS Ouput:

Maximum Hourly Emission Rate:

July =	744	hours
July Max Fuel =	32,551,686	gallons/month
Greatest monthly total standing plus working loss - July	582.17	lb/month
Maximum VOC emission rate =	0.78	lb/hr

Annual Total Emission Rate:

Annual total standing plus working losses =	1174.2	lb/year
PTE =	0.59	tons/yr

Tank Specifications Used:

Vertical fixed roof
Vented to atmosphere, default breather vent +/- 0.03 psig
Non-heated
Flat roof
Shell in good condition
65,700,000 gallons/year throughput
617,000 gallons capacity

106 turnovers/year Throughput/capacity)
Average liquid height in tank 1/2 tank height

Florida GE 7FA Turbine
Summary of Facility HAP Emissions

		3500 hrs Natural Gas	2000 hrs NG	1500 hrs Oil	2000 hrs NG & 1500 hrs Oil	CTGs All Cases	Fuel Heater	Facility Total
Total HAPs	tpy	5.0	2.9	3.1	6,0	6.0	0.04	6.0
Max HAP	tpy	2.6	1.5	1.9	1.9	2.6	4.01E-02	2.6
Max HAP Compound		Formaldehyde	Formaldehyde	Manganese	Formaldehyde	Formaldehyde	Hexane	
Major Total HAPs								**No**
Major Single HAP								**No**

Calculations and Computations

HAP Emissions from Simple Cycle CTG Facility

Project:	Florida GE 7FA Turbine		
Project Number:	6792-140	**Computed by:** M. Behnke	**Date:** 9/21/00
Subject:	Natural Gas Turbine Non-Criteria Regulated Pollutant Emissions	**Checked by:** M. Griffin	**Date:**

Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas (lb/10^6scf)	Emission Factor (lb/MMBtu)[d]	Rating	CTG Natural Gas Combustion: Maximum Heat Input, per turbine (MMBtu/Hr)[b]	CTG Natural Gas Combustion: Average Heat Input, per turbine (MMBtu/Hr)[c]	Natural Gas Fired CTG Emissions: Emission Rate, Per Turbine Hourly[e] (lb/hr)	Natural Gas Fired CTG Emissions: Emission Rate, Per Turbine Annual[f] (tpy)	Facility: Emission Rate All 3 CTGs Hourly[f] (lb/hr)	Facility: Emission Rate All 3 CTGs Annual[f] (tpy)	Facility Major Source (Y/N)
1,3-Butadiene	HAP		4.30E-07	D	1,892.6	1,830.4	8.14E-04	1.38E-03	2.44E-03	4.13E-03	No
Acetaldehyde	HAP		4.00E-05	C	1,892.6	1,830.4	7.57E-02	1.26E-01	2.27E-01	3.84E-01	No
Acrolein	HAP		6.40E-06	C	1,692.6	1,630.4	1.21E-02	2.05E-02	3.63E-02	6.15E-02	No
Benzene [g]	HAP	1.36E-02	1.33E-05	B	1,692.6	1,630.4	2.52E-02	4.27E-02	7.57E-02	1.28E-01	No
Ethylbenzene	HAP		3.20E-05	C	1,692.6	1,830.4	6.06E-02	1.03E-01	1.82E-01	3.08E-01	No
Formaldehyde [h]	HAP	2.72E-01	2.66E-04		1,692.8	1,830.4	5.04E-01	8.53E-01	1.51E+00	2.56E+00	No
Naphthalene	HAP		1.30E-06	C	1,692.8	1,630.4	2.46E-03	4.16E-03	7.38E-03	1.25E-02	No
PAHs	HAP		2.20E-06	C	1,892.6	1,830.4	4.16E-03	7.05E-03	1.25E-02	2.11E-02	No
Propylene Oxide	HAP		2.90E-05	D	1,692.6	1,830.4	5.49E-02	9.29E-02	1.65E-01	2.79E-01	No
Toluene [g]	HAP	7.10E-02	6.96E-05	B	1,692.6	1,830.4	1.32E-01	2.23E-01	3.95E-01	6.69E-01	No
Xylene	HAP		6.40E-05	C	1,892.6	1,830.4	1.21E-01	2.05E-01	3.63E-01	6.15E-01	No

	Hours of Operation
Natural Gas CTG	3,500
Number of Turbines	3

		Major Source
Total HAPs	5.0	No
Maximum Individual HAP	2.6	No

Natural Gas Heating Value [i] 1020 Btu/SCF (HHV)
908 Btu/SCF (LHV)

Notes:

(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions.
(d) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (1040 Btu/scf)
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (2,500 hr/yr) / (2,000 lb/ton)
(g) Emission Factors from CARB CATEF emission factor database for natural gas fired combustion turbines.
(h) Modified from AP-42 Section 3.1 emissions database for large turbines.
(i) Natural gas heating value is taken from a gas analysis report provided by Duke Energy.

Calculations and Computations
HAP Emissions from Simple Cycle CTG Facility

Project:	Florida GE 7FA Turbine		
Project Number:	6792-140	Computed by: M. Behnke	Date: 9/21/00
Subject:	Natural Gas Turbine Non-Criteria Regulated Pollutant Emissions	Checked by: M. Griffin	Date:

Pollutant	Type[a]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine Natural Gas			CTG Natural Gas Combustion		Natural Gas Fired CTG Emissions		Facility		Facility
					Maximum Heat Input, per turbine	Average Heat Input, per turbine	Emission Rate, Per Turbine		Emission Rate All 3 CTGs		Major Source
		($lb/10^6 scf$)	(lb/MMBtu)[d]	Rating	(MMBtu/Hr)[b]	(MMBtu/Hr)[c]	Hourly[e] (lb/hr)	Annual[f] (tpy)	Hourly[e] (lb/hr)	Annual[f] (tpy)	(Y/N)
1,3-Butadiene	HAP		4.30E-07	D	1,892.6	1,830.4	8.14E-04	7.87E-04	2.44E-03	2.36E-03	No
Acetaldehyde	HAP		4.00E-05	C	1,892.6	1,830.4	7.57E-02	7.32E-02	2.27E-01	2.20E-01	No
Acrolein	HAP		6.40E-06	C	1,892.8	1,830.4	1.21E-02	1.17E-02	3.63E-02	3.51E-02	No
Benzene [g]	HAP	1.36E-02	1.33E-05	B	1,892.6	1,830.4	2.52E-02	2.44E-02	7.57E-02	7.32E-02	No
Ethylbenzene	HAP		3.20E-05	C	1,892.6	1,630.4	6.06E-02	5.86E-02	1.82E-01	1.76E-01	No
Formaldehyde [h]	HAP	2.72E-01	2.66E-04		1,892.6	1,830.4	5.04E-01	4.87E-01	1.51E+00	1.46E+00	No
Naphthalene	HAP		1.30E-06	C	1,892.6	1,830.4	2.46E-03	2.38E-03	7.38E-03	7.14E-03	No
PAHs	HAP		2.20E-06	C	1,892.6	1,830.4	4.16E-03	4.03E-03	1.25E-02	1.21E-02	No
Propylene Oxide	HAP		2.90E-05	D	1,892.6	1,830.4	5.49E-02	5.31E-02	1.65E-01	1.59E-01	No
Toluene [g]	HAP	7.10E-02	6.96E-05	B	1,892.6	1,830.4	1.32E-01	1.27E-01	3.95E-01	3.82E-01	No
Xylene	HAP		6.40E-05	C	1,892.6	1,830.4	1.21E-01	1.17E-01	3.63E-01	3.51E-01	No

	Hours of Operation
Natural Gas CTG	2,000
Number of Turbines	3

Total HAPs	2.9	No
Maximum Individual HAP	1.5	No

Natural Gas Heating Value [i] 1020 Btu/SCF (HHV)
908 Btu/SCF (LHV)

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions.
(d) Emission Factor (lb/MMBtu) = (Emission Factor, $lb/10^6$ scf) / (1040 Btu/scf)
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (2,000 hr/yr) / (2,000 lb/ton)
(g) Emission Factors from CARB CATEF emission factor database for natural gas fired combustion turbines.
(h) Modified from AP-42 Section 3.1 emissions database for large turbines.
(i) Natural gas heating value is taken from a gas analysis report provided Duke Energy.

Calculations and Computations
HAP Emissions from Simple Cycle CTG Facility

Project:	Florida GE 7FA Turbine			
Project Number:	6792-140	**Computed by:** M. Behnke	**Date:**	9/21/00
Subject:	Distillate Oil-Fired Turbine Non-Criteria Regulated Pollutant Emissions	**Checked by:** M. Griffin	**Date:**	

Pollutant	Type[(a)]	Emission Factor AP-42 Section 3.1 04/00 - Combustion Turbine - Distillate Oil (lb/10³gal)	Emission Factor (lb/MMBtu)[(d)]	Rating	CTG Distillate Oil Combustion: Maximum Heat Input, per turbine (MMBtu/Hr)[(b)]	CTG Distillate Oil Combustion: Average Heat Input, per turbine (MMBtu/Hr)[(c)]	Distillate Oil-Fired CTG Emissions: Emission Rate, Per Turbine Hourly[(e)] (lb/hr)	Distillate Oil-Fired CTG Emissions: Emission Rate, Per Turbine Annual[(f)] (tpy)	Facility: Emission Rate All 6 CTGs Hourly[(e)] (lb/hr)	Facility: Emission Rate All 6 CTGs Annual[(f)] (tpy)	Facility Major Source (Y/N)
1,3-Butadiene	HAP		1.60E-05	D	1,225.8	1,066.4	1.96E-02	1.28E-02	5.88E-02	3.84E-02	No
Benzene	HAP		5.50E-05	C	1,225.8	1,066.4	6.74E-02	4.40E-02	2.02E-01	1.32E-01	No
Formaldehyde	HAP		2.80E-04	B	1,225.8	1,066.4	3.43E-01	2.24E-01	1.03E+00	6.72E-01	No
Naphthalene	HAP		3.50E-05	C	1,225.8	1,066.4	4.29E-02	2.80E-02	1.29E-01	8.40E-02	No
PAHs	HAP		4.00E-05	C	1,225.8	1,066.4	4.90E-02	3.20E-02	1.47E-01	9.60E-02	No
Arsenic	HAP		1.10E-05	D	1,225.8	1,066.4	1.35E-02	8.80E-03	4.04E-02	2.64E-02	No
Beryllium	HAP		3.10E-07	D	1,225.8	1,066.4	3.80E-04	2.48E-04	1.14E-03	7.44E-04	No
Cadmium	HAP		4.80E-06	D	1,225.8	1,066.4	5.88E-03	3.84E-03	1.77E-02	1.15E-02	No
Chromium	HAP		1.10E-05	D	1,225.8	1,066.4	1.35E-02	8.80E-03	4.04E-02	2.64E-02	No
Lead	HAP		1.40E-05	D	1,225.8	1,066.4	1.72E-02	1.12E-02	5.15E-02	3.36E-02	No
Manganese	HAP		7.90E-04	D	1,225.8	1,066.4	9.68E-01	6.32E-01	2.91E+00	1.90E+00	No
Mercury	HAP		1.20E-06	D	1,225.8	1,066.4	1.47E-03	9.60E-04	4.41E-03	2.88E-03	No
Nickel	HAP		4.60E-06	D	1,225.8	1,066.4	5.64E-03	3.68E-03	1.69E-02	1.10E-02	No
Selenium	HAP		2.50E-05	D	1,225.8	1,066.4	3.06E-02	2.00E-02	9.19E-02	6.00E-02	No

	Hours of Operation
Distillate Oil CTG	1,500
Number of Turbines	3

Total HAPs	3.1	No
Maximum Individual HAP	1.9	No

Distillate Oil Heating Value 139 MMBtu/10³ gal (HHV)
125 MMBtu/10³ gal (LHV)

Notes:
(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.
(b) Maximum heat input rate for turbine is based on HHV data at ambient temperature of -15°F and 100% load operating conditions.
(c) Average heat input rate is based on HHV data at an average ambient temperature of 47.1°F and 100% load operating conditions.
(d) Emission factors from AP-42, Section 3.1, Tables 3.1-4 and 3.1-5.
(e) Hourly Emission Rate (lb/hr) = [Heat Input Rate (MMBtu/Hr) * Emission Factor (lb/MMBtu)]
(f) Annual Emission Rate (tpy) = (Average Hourly Emission Rate, lb/hr) * (500 hr/yr) / (2,000 lb/ton)

Calculations and Computations

HAP Emissions

Project:	Florida GE 7FA Turbine		
Project Number:	6792-140	**Computed by:**	M. Griffin
Subject:	Natural Gas Fuel Heater Non-Criteria Regulated Pollutant Emissions	**Checked by:**	

					Auxiliary Boiler Natural Gas Combustion		Auxiliary Boiler Emissions		Facility		Facility
Pollutant	Type[a]	Emission Factor AP-42 Section 1.4 03/98 - Natural Gas Combustion (lb/10^6scf)	(lb/MMBtu)[b]	Rating	Maximum Heat Input, per boiler (MMBtu/Hr)	Averge Heat Input, per boiler (MMBtu/Hr)	Emission Rate, Per Boiler Hourly[c] (lb/hr)	Annual[d] (tpy)	Emission Rate All CTG/DB/HRSGs Hourly[c] (lb/hr)	Annual[d] (tpy)	Major Source (Y/N)
1,3-Butadiene	HAP				13	13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	No
2-Methylnaphthalene	HAP	2.40E-05	2.35E-08	D	13	13	3.06E-07	5.35E-07	3.06E-07	5.35E-07	No
3-Methylchloranthrene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
7,12-Dimethylbenz(a)anthracene	HAP	1.60E-05	1.57E-08	E	13	13	2.04E-07	3.57E-07	2.04E-07	3.57E-07	No
Acenaphthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Acenaphthylene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Anthracene	HAP	2.40E-06	2.35E-09	E	13	13	3.06E-08	5.35E-08	3.06E-08	5.35E-08	No
Benz(a)anthracene	HAP	1.80E-06	1.76E-09		13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Benzene	HAP	2.10E-03	2.06E-06	B	13	13	2.68E-05	4.68E-05	2.68E-05	4.68E-05	No
Benzo(a)pyrene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Benzo(b)flouoranthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Benzo(g,h,l)perylene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Benzo(k)fluoranthene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Chrysene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Dibenzo(a,h)anthracene	HAP	1.20E-06	1.18E-09	E	13	13	1.53E-08	2.68E-08	1.53E-08	2.68E-08	No
Dichlorobenzene	HAP	1.20E-03	1.18E-06	E	13	13	1.53E-05	2.68E-05	1.53E-05	2.68E-05	No
Fluoranthene	HAP	3.00E-06	2.94E-09	E	13	13	3.82E-08	6.69E-08	3.82E-08	6.69E-08	No
Fluorene	HAP	2.80E-06	2.75E-09	E	13	13	3.57E-08	6.25E-08	3.57E-08	6.25E-08	No
Formaldehyde	HAP	7.50E-02	7.35E-05	B	13	13	9.56E-04	1.67E-03	9.56E-04	1.67E-03	No
Hexane	HAP	1.80E+00	1.76E-03		13	13	2.29E-02	4.01E-02	2.29E-02	4.01E-02	No
Indeno(1,2,3-cd)pyrene	HAP	1.80E-06	1.76E-09	E	13	13	2.29E-08	4.01E-08	2.29E-08	4.01E-08	No
Naphthalene	HAP	6.10E-04	5.98E-07	E	13	13	7.77E-06	1.36E-05	7.77E-06	1.36E-05	No
Phenanathrene	HAP	1.70E-05	1.67E-08	D	13	13	2.17E-07	3.79E-07	2.17E-07	3.79E-07	No
Pyrene	HAP	5.00E-06	4.90E-09	E	13	13	6.37E-08	1.12E-07	6.37E-08	1.12E-07	No
Toluene	HAP	3.40E-03	3.33E-06	C	13	13	4.33E-05	7.58E-05	4.33E-05	7.58E-05	No
Arsenic	HAP	2.00E-04	1.96E-07	E	13	13	2.55E-06	4.46E-06	2.55E-06	4.46E-06	No
Barium	HAP	4.40E-03	4.31E-06	D	13	13	5.61E-05	9.81E-05	5.61E-05	9.81E-05	No
Beryllium	HAP	1.20E-05	1.18E-08	E	13	13	1.53E-07	2.68E-07	1.53E-07	2.68E-07	No
Cadmium	HAP	1.10E-03	1.08E-06	D	13	13	1.40E-05	2.45E-05	1.40E-05	2.45E-05	No
Chromium	HAP	1.40E-03	1.37E-06	D	13	13	1.78E-05	3.12E-05	1.78E-05	3.12E-05	No
Cobalt	HAP	8.40E-05	8.24E-08	D	13	13	1.07E-06	1.87E-06	1.07E-06	1.87E-06	No
Copper	HAP	8.50E-04	8.33E-07	C	13	13	1.08E-05	1.90E-05	1.08E-05	1.90E-05	No
Lead	HAP	5.00E-04	4.90E-07	D	13	13	6.37E-06	1.12E-05	6.37E-06	1.12E-05	No
Manganese	HAP	3.80E-04	3.73E-07	D	13	13	4.84E-06	8.48E-06	4.84E-06	8.48E-06	No
Mercury	HAP	2.60E-04	2.55E-07	D	13	13	3.31E-06	5.80E-06	3.31E-06	5.80E-06	No
Molybdenum	HAP	1.10E-03	1.08E-06	D	13	13	1.40E-05	2.45E-05	1.40E-05	2.45E-05	No
Nickel	HAP	2.10E-03	2.06E-06	C	13	13	2.68E-05	4.68E-05	2.68E-05	4.68E-05	No
Selenium	HAP	2.40E-05	2.35E-08	E	13	13	3.06E-07	5.35E-07	3.06E-07	5.35E-07	No
Vanadium	HAP	2.30E-03	2.25E-06	D	13	13	2.93E-05	5.13E-05	2.93E-05	5.13E-05	No
Zinc	HAP	2.90E-02	2.84E-05	E	13	13	3.70E-04	6.47E-04	3.70E-04	6.47E-04	No

Hours of Operation

Auxiliary Boiler	3,500	**Facility Total HAPs**	**0.04**	**No**
Number of Auxiliary Boilers per Facility	1	**Maximum Individual HAP**	**0.04**	**No**
Natural Gas Heating Value	1020 Btu/SCF (HHV)			

Notes:

(a) Type = NC for Non-Criteria Pollutants, HAP/POM for compounds included as polycyclic organic matter or HAP for Hazardous Air Pollutant.

(b) Emission Factor (lb/MMBtu) = (Emission Factor, lb/10^6 scf) / (1,020 Btu/scf)

(c) Hourly Emission Rate (lb/hr) = [Heat Input (MMBtu/Hr) * Emission Factor (lb/MMBtu)]

(d) Annual Emission Rate (tpy) = (Hourly Emission Rate, lb/hr) * (8,760 hr/yr) / (2,000 lb/ton)

Calculations and Computations

Project:	**Florida GE 7FA Turbine**	**Computed by:** L. Sherburne	**Date:** 7/19/00
Project Number:	6792-140	**Checked by:** M. Griffin	**Date:** 9/21/00
Subject:	**Formaldehyde Emission Factor**		

Facility	Manufacturer	Model	Rating	AP-42 1998 Draft	Large Turbines (>70 MW)
			(MW)	*(lb/Mmcuft)*	*(lb/Mmcuft)*
Gilroy Energy Co./Gilroy, CA	General Electric	Frame 7	87	0.722160	0.722160
Sithe Energies, 32nd St. Naval S/San Diego, CA	General Electric	MS6000	44	0.110160	
SD Gas & Electric Co./San Diego, CA	General Electric	5221	17	0.483480	
Modesto Irrigation District/Mclure/Modesto, CA	General Electric	Frame 7B	50	0.135660	
Willamette Industries, Inc./Oxnard, CA	General Electric	LM2500-PE	67.4	0.044982	
Sycamore Cogen. Co./Bakersfield, CA	General Electric	Frame 7	75	0.085884	0.085884
Calpine / Agnews Cogen./San Jose, CA	General Electric	LM5000	23.33	0.063036	
Dexzel Inc./Bakersfield, CA	General Electric	LM2500	29.1	0.026520	
Procter & Gamble Manufacturing/Sacramento, CA	General Electric	LM2500	20.5	0.088434	
Chevron Inc./Gaviota, CA	Allison	K501	2.5	3.570000	
Ell / Stewart & Stevenson/Berkeley, CA	General Electric	LM2500	25	0.480420	
Calpine Corp./Sumas, WA	General Electric	MS7001EA	87.83	0.006834	0.006834
Sargent Canyon Cogen/Bakersfield, CA	General Electric	Frame 6	42.5	0.059568	
Watsonville Cogen, Partnership/Watsonville, CA	General Electric	LM 2500	24	0.091596	
Southern Cal. Edison Co./Long Beach, CA	Brown-Boveri-Sulzer	11-D	61.75	1.326000	
NR/NR	General Electric	Frame 3	7.7	0.265200	
NR/NR	General Electric	Frame 3	7.7	0.427380	
NR/NR	Solar	T12000	9.4	0.015810	
NR/NR	Solar	T12000	9.4	9.618600	
NR/NR	General Electric	LM1500	10.6	4.273800	
NR/NR	General Electric	LM1500	10.6	25.908000	
Southern Cal. Edison Co./Coolwater, CA	Westinghouse	PACE520	63	38.964000	
Southern Cal. Edison Co./Coolwater, CA	Westinghouse	PACE520	63	0.350880	
Imperial Irrigation D / Choachella/Imperial, CA	General Electric	NS5000P	46.3	0.306000	
Bonneville Pacific Corp./Somis, CA	Solar	Mars	9	0.743580	
WSPA/SWEPI GT/Bakersfield, CA	Allison	501 KB5	4	0.013872	
			Mean (lb/Mmcuft)	3.39	0.27

Note: The AP-42 1998 Draft document calculates the proposed Formaldehyde Emission factor as an average of all of the test data present in the data base. For the purposes of calculating an appropriate emission factor for this project only the data presented for large turbines has been used.

APPENDIX C

BACT SUPPORTING INFORMATION

Table C-1
PRICE QUOTE ADJUSTMENTS
Enron - Florida
General Electric 7 FA Turbine

NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 EA - Proposed option with DLN to 15 ppm

	Hours of Operation
3,500	
$4,069,564	Budgetary cost for SCR (without auxiliaries)[1]
$1,972,280	Catalyst Support Structure
$2,097,284	Catalyst Bed
$4,069,564	Budgetary cost for SCR (without auxiliaries)
$100,000	Auxiliaries not included in Engelhard quote = ($10k per tank + $20K insulation and heating + $20k pumps, piping flow meters, safety equipment) x 2 tanks = $100k
$262,160	Spare Catalyst = 1 spare catalyst on site at all times for 8 turbines
$4,431,724	

Carbon Monoxide High Temperature Oxidation Catalyst - Top Control Option
Simple Cycle, General Electric 7 EA, Baseline and Proposed Control Option

$1,319,483	Budgetary cost for CO catalyst (without auxililiaries)[1]
$638,908	Catalyst Support Structure
$666,686	Catalyst Bed
$1,319,483	*Oxidation System (catalyst and structure)*
$50,000	Transition = Transition piece , stainless steel, spool piece, = $50k
$20,000	Crane = Crane to handle modules = $20k
$30,000	Fan = Dilution air fan, variable speed drive, ductwork, starter = $30k
$83,336	Spare Catalyst = 1 spare catalyst on site at all times for 8 turbines
$1,502,819	

[1]The 11/13/98 Engelhard quote was provided for a combined CO oxidation and SCR system.
The original quotation has been adjusted for separate oxidation and SCR systems.
The original quotation has also been escalated to reflect current control system costs using the Vatavuk Air Pollution Control Cost Indexes per OAQPS control cost manual.
The original quotation has also been used to estimate catalyst costs for differing operating scenarios.

Table C-1A
Enron - Florida
General Electric 7 FA Turbine
Control Equipment Cost Adjustment

Budgetary Cost	Costs from Engelhard Quote		Estimated Costs [4]	Scaled Estimated Costs[5]
Turbine Operation (hrs/year)	3,500	2,000	3,500	3,500
Base Exhaust Air Flow (lb/hr)	2,728,000			
Actual Exhaust Air Flow (lb/hr)	3,789,000			
Original Quotation Costs [1]				
Total System (SCR & Oxidation Catalyst)	3,600,000	3,000,000		
Replacement CO	450,000	360,000		
Replacement ZNX	1,400,000	1,000,000		
Support Equipment Cost	1,750,000	1,640,000		
Total Catalyst Cost	1,850,000	1,360,000		
Catalyst Cost/Total Cost	51.4%	45.3%		
SCR System Only [2]				
SCR Costs from 11/13/98 Quote				
Cost Index [3]	104.2			
Support Equipment	1,320,000	1,210,000	1,320,000	1,833,387
Catalyst Cost	1,400,000	1,000,000	1,400,000	1,944,501
Total Cost	2,720,000	2,210,000	2,720,000	3,777,889
Escalated Cost for June 2000				
Cost Index [3]	112.3			
Support Equipment	1,420,000	1,300,000	1,420,000	1,972,280
Catalyst Cost	1,510,000	1,080,000	1,510,000	2,097,284
Total Cost	2,930,000	2,380,000	2,930,000	4,069,564
Oxidation Catalyst System only [2]				
Costs from 11/13/98 Quote				
Cost Index [3]	104.2			
Support Equipment	430,000	430,000	430,000	597,240
Catalyst Cost	450,000	360,000	450,000	625,018
Total Cost	880,000	790,000	880,000	1,222,258
Escalated Cost for June 2000				
Cost Index [3]	112.3			
Support Equipment	460,000	460,000	460,000	638,908
Catalyst Cost	480,000	390,000	480,000	666,686
Total Cost	950,000	850,000	950,000	1,319,483

Notes:
1 - From original Engelhard quotation, November 13, 1998
2 - Original quotation was provided for a combined SCR/Oxidation Catalyst System. For BACT analysis costs have been separated.
3 - Vatavuk Air Pollution Control Cost Index for Catalytic Incinerators. Base index 4th quarter 1998, Escalated index 2nd quarter 2000.
4 - Costs for reduced operation scenarios calculated assuming linear relationship between hours of operation and equipment cost.
5- Original quotation was provided for GE 7 EA Turbines. Costs scaled for GE 7FA based on exhaust flow rate.
Scaled Cost = Originial Cost x Actual Exhaust Air Flow / Base Exhaust Air Flow

TABLE C-2
Enron - Florida
NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	61%

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	3,500
Natural Gas Firing (Normal Operation)	2,000
Distillate Oil Firing (Normal Operation)	1,500
Source(s) Controlled	One Power Block, 175 MW
NOx From Normal Natural Gas Operation (lb/hr)[1]	79.5
NOx From Distillate Oil Operation (lb/hr)	321.0
NOx From Source(s) (tpy)	300.4
Site Specific Enclosure (Building) Cost	NA
Site Specific Electricity Value ($/kWh)	0.10
Site Specific Natural Gas Cost ($/MMBtu)	NA
Site Specific Operating Labor Cost ($/hr)	30
Site Specific Maint. Labor Cost ($/hr)	30

[1]NOx emissions are based on data at 100% load and intake air chilled to maximum of 50°F.

Capital Costs[1]

	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$4,431,724	Engelhard Quote plus auxiliaries, A
b.) Instrumentation	$443,200	0.10 x A
c.) Sales taxes	$265,900	0.06 x A
d.) Freight	$221,600	0.05 x A
Total Purchased equipment cost, (PEC)	$5,362,424	B = 1.21 x A
2.) Direct installation costs		
a.) Foundations and supports	$429,000	0.08 x B
b.) Handling and erection	$750,700	0.14 x B
c.) Electrical	$214,500	0.04 x B
d.) Piping	$107,200	0.02 x B
e.) Insulation for ductwork	$53,600	0.01 x B
f.) Painting	$53,600	0.01 x B
Total direct installation cost	$1,608,600	*0.30 x B*
3.) Site preparation, SP	NA	NA
4.) Buildings, Bldg	NA	NA
Total Direct Cost, DC	$6,971,000	1.30B + SP + Bldg
Indirect Costs (installation)		
5.) Engineering	$536,200	0.10 x B
6.) Construction and field expenses	$268,100	0.05 x B
7.) Contractor fees	$536,200	0.10 x B
8.) Start-up	$107,200	0.02 x B
9.) Performance test	$53,600	0.01 x B
10.) Contingencies	$160,900	0.03 x B
11.) Simple Interest During Construction	$244,000	DC x 7% x 0.5 years
Total Indirect Cost, IC	$1,906,200	0.28B
Total Capital Investment (TCI) = DC + IC	**$8,877,200**	**1.58B + SP + Bldg**

1 See Appendix C, Tables C-1 and C-1A

TABLE C-2
Enron - Florida
NOx High Temperature SCR - Top Control Option
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	61%

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Catalyst Press. Drop (in. W.C.)	3.0	Pressure drop - catalyst bed	Vendor, estimate
Power Output of Turbine (kW)	175,000	Output at Average Conditions	
Power Loss Due to Pressure Drop (%)	0.32%	0.105% for every 1" pressure drop	Vendor
Power Loss Due to Pressure Drop (kW)	551		
Unit Cost ($/kW-hr)	$0.10	Estimated Market Value	Estimate
Cost of Heat Rate Loss ($)	$192,940		
Power Loss Due to Extended Startups (kW-hr)	13,125,000	Extended startup time due to catalyst bed	Estimate
Cost of Extra Startups ($/yr)	$1,312,500	$0.10/kW	
Total Cost ($/yr)	$1,505,440		
2) Operating Labor			
SCR Requirement (hr/yr)	218.75	1/2 hr/shift, 3,500 hours per year	Estimate
Ammonia Delivery Requirement (hr/yr)	24	3 deliveries per year, 8 hr/delivery	Estimate
Ammonia Recordkeeping/Reporting (hr/yr)	40.0	One week of reporting	Estimate
Catalyst Cleaning (hr/yr)	80.0	2 workers x 40 hours per year	
Unit Cost ($/hr)	*$30.00*	*Facility Data*	Estimate
Cost ($/yr)	$10,883		
3) Supervisory Labor			
Cost ($/yr)	*$1,630*	*15% Operating Labor*	*OAQPS*
4) Maintenance			
SCR Labor Req. (hr/yr)	218.75	1/2 hour per shift	OAQPS
Catalyst Replacement Labor Req. (hr/yr)	106.7	*8 workers, 40 hours every 3 yrs*	Estimate
Ammonia System Maintenance Labor Req. (hr/yr)	365.0	1 hr/day, 365 day/yr	Estimate
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Labor Cost ($/yr)	$20,713		
Material Cost ($/yr)	$20,710	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$41,420		
5) Ammonia Requirement			
Requirement (ton/yr)	100	Ammonia requirement, 0.5436 lb NH3/lb NOx Removed	Vendor
Unit Cost ($/ton)	$315	*For pure ammonia*	Chemical Market Reporter
Total Cost ($/yr)	$31,430		
6) Process Air			
Requirement (scf/lb NH3)	350		Vendor
Requirement (Mscf/yr)	69,843		Vendor
Unit Cost ($/Mscf)	$0.20	Peters and Timmerhaus	Standard
Total Cost ($/yr)	$13,970		
7) Catalyst Replacement			
Catalyst Cost ($)	$2,097,284	Catalyst modules	Vendor
Catalyst Disposal Cost ($)	$50,000	Disposal of catalyst modules	Estimate
Sales Tax ($)	$104,864	5% sales tax in Indiana	Estimate
Catalyst Life (yrs)	3	n	OAQPS
Interest Rate (%)	7	i	
CRF	0.381	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$858,180	(Volume)(Unit Cost)(CRF)	
8) Indirect Annual Costs			
Overhead	$32,400	60% of O&M Costs	OAQPS
Administration	$177,500	2% of Total Capital Investment	OAQPS
Property Tax	$88,770	1% of Total Capital Investment	OAQPS
Insurance	$88,770	1% of Total Capital Investment	OAQPS
Capital Recovery	$955,000	10 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	$1,342,440		

Total Annualized Cost ($/yr)	$3,805,400
Total NOx Controlled (tpy)	183.5
Cost Effectiveness ($/ton)	$20,700

Table C-3
Enron - Florida
Carbon Monoxide High Temperature Oxidation Catalyst
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	90%

Facility Input Data

Item	Value
Operating Schedule	
Shifts per day	3
Hours per day	24
Days per week	7
Total Hours per year	3,500
Natural Gas Firing (Normal Operation)	2,000
Distillate Oil Firing (Normal Operation)	1,500
Source(s) Controlled[1]	One Power Block, 175 MW
CO From Normal Natural Gas Operation (lb/hr)	29.6
CO From Distillate Oil Operation (lb/hr)	66.6
CO From Source(s) (tpy)	79.6
Site Specific Enclosure (Building) Cost	NA
Site Specific Electricity Value ($/kWh)	0.10
Site Specific Natural Gas Cost ($/MMBtu)	NA
Site Specific Operating Labor Cost ($/hr)	30
Site Specific Maint. Labor Cost ($/hr)	30

[1]CO emissions are based on data at 100% load and intake air chilled to maximum of 50°F.

Capital Costs[1]

Item	Value	Basis
Direct Costs		
1.) Purchased Equipment Cost		
a.) Equipment cost + auxiliaries	$1,502,819	Scaled Engelhard quote + auxiliaries, A
b.) Instrumentation	$150,300	0.10 x A
c.) Sales taxes	$75,100	0.05 x A
d.) Freight	$90,200	0.06 x A
Total Purchased equipment cost, (PEC)	$1,818,419	B = 1.21 x A
2.) Direct installation costs		
a.) Foundations and supports	$145,500	0.08 x B
b.) Handling and erection	$254,600	0.14 x B
c.) Electrical	$72,700	0.04 x B
d.) Piping	$36,400	0.02 x B
e.) Insulation for ductwork	$18,200	0.01 x B
f.) Painting	$18,200	0.01 x B
Total direct installation cost	$545,600	0.30 x B
3.) Site preparation, SP	NA	NA
4.) Buildings, Bldg	NA	NA
Total Direct Cost, DC	$2,364,000	1.30B + SP + Bldg
Indirect Costs (Installation)		
5.) Engineering	$181,800	0.10 x B
6.) Construction and field expenses	$90,900	0.05 x B
7.) Contractor fees	$181,800	0.10 x B
8.) Start-up	$36,400	0.02 x B
9.) Performance test	$18,200	0.01 x B
10.) Contingencies	$54,600	0.03 x B
11.) Simple Interest During Construction	$82,700	DC x 7% x 0.5 years
Total Indirect Cost, IC	$646,400	0.28B
Total Capital Investment (TCI) = DC + IC	$3,010,400	1.58B + SP + Bldg

1 See Appendix C, Tables C-1 and C-1A

Table C-3
Enron - Florida
Carbon Monoxide High Temperature Oxidation Catalyst
Simple Cycle, General Electric 7 FA

Control Efficiency (%)	90%

Annual Costs

Item	Value	Basis	Source
1) Electricity			
Press. Drop (in. W.C.)	3.0	Pressure drop - catalyst bed	Vendor
Power Output of Turbine (kW)	175,000		
Power Loss Due to Pressure Drop (%)	0.32%	0.105% for every 1" pressure drop	Vendor
Power Loss Due to Pressure Drop (kW)	551		
Unit Cost ($/kWh)	$0.10	Estimated Market Value	Estimate
Cost of Heat Rate Loss ($/yr)	$192,940		
Power Loss Due to Extended Startups (kW-hr)	13,125,000	*Extended startup time due to catalyst bed*	*Estimate*
Cost of Extra Startups ($/yr)	$1,312,500	$0.10/kWh	
Total Cost ($/yr)	$1,505,440		
2) Operating Labor			
Requirement (hr/yr)	218.75	1/2 hr/shift, 3,500 hours per year	OAQPS
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Cost ($/yr)	$6,560		
3) Supervisory Labor			
Cost ($/yr)	$980	15% Operating Labor	OAQPS
4) Maintenance			
Labor Req. (hr/shift)	218.75	1/2 hour per shift	OAQPS
Unit Cost ($/hr)	$30.00	Facility Data	Estimate
Labor Cost ($/yr)	$6,563		
Material Cost ($/yr)	$6,560	100% of Maintenance Labor	OAQPS
Total Cost ($/yr)	$13,120		
7) Catalyst Replacement			
Catalyst Cost ($)	$666,686	Catalyst modules	Vendor
Catalyst Disposal Cost ($)	$50,000	Disposal of catalyst modules	Estimate
Sales Tax ($)	$33,334	5% sales tax in Indiana	Estimate
Catalyst Life (yrs)	3	n	OAQPS
Interest Rate (%)	7	i	
CRF	0.38	Amortization of Catalyst	OAQPS
Annual Cost ($/yr)	$285,800	(Volume)(Unit Cost)(CRF)	
9) Indirect Annual Costs			
Overhead	$12,400	60% of O&M Costs	OAQPS
Administration	$60,200	2% of Total Capital Investment	OAQPS
Property Tax	$30,100	1% of Total Capital Investment	OAQPS
Insurance	$30,100	1% of Total Capital Investment	OAQPS
Capital Recovery	$335,200	10 yr life; 7% interest (-cat. cost)	OAQPS
Total Indirect ($/yr)	*$468,000*		

Total Annualized Cost ($/yr)	**$2,279,900**
Total CO Controlled (tpy)	**71.6**
Cost Effectiveness ($/ton)	**$31,800**

COVER SHEET

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE: November 13, 1998 NO. PAGES 11 (INCLUDING COVER)

TO:

ENGELHARD
ATTN: Nancy Ellison

FROM: Fred Booth Ph 410-569-0297 // FAX 410-569-1841

RE: Simple Cycle Turbines
Oxidation Catalyst Components
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal

Added data and pricing for 2,000 hr/yr operation.

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
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2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

November 13, 1998

RE: **Simple Cycle Turbines**
Oxidation Catalyst Components
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal EPB98283-Rev. 1

Dear .

We provide Engelhard Budgetary Proposal for Engelhard Camet® CO Oxidation Catalyst System Components and NOxCAT ZNX™ High Temperature SCR Catalyst system components for the above projects. This is per your FAXes of November 10 and 11, 1998.

Our Budgetary Proposal is based on:

- Given data for GE 7EA, Westinghouse 501D5A, and Westinghouse 501F Gas Turbines operating in simple cycle mode for both 3,500 hours/year and 2,000 hours/year operation;
- Oxidation Catalysts for CO reductions as noted;
- Catalyst for NOx reductions as noted with ammonia slip of 5 ppmvd@15%O_2;
- Delta P through CO and SCR systems of Nominal 4"WG;
- Assumed internally insulated ducts with cross sections at the catalyst as illustrated. Note that all transitions are based on assumed turbine discharge cross section of 15 ft. x 15 ft.;
- Scope as noted. Please note that we have assumed horizontal gas flow through the CO / SCR reactor and the use of 28% aqueous ammonia. The systems for the GE 7EA and Westinghouse 501F require the use of an ambient air cooling system to reduce the gas temperature to the SCR catalyst.
- Three (3) Year Performance Guarantee (expected life five to seven years).

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Sales Engineer

cc: Nancy Ellison - Proposal Administrator

ENGELHARD

ENRON
Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB98283-Rev. 1
November 13, 1998

ENGELHARD CORPORATION
CAMET™ CO CATALYST SYSTEM
NOxCAT ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **CAMET™** metal substrate CO Catalyst System components and the **NOxCAT ZNX™** ceramic substrate SCR system components summarized herein.

NOxCAT ZNX™ High Temperature SCR Catalyst System: Scope of Supply

1. Engelhard **CAMET® CO** and **NOxCAT ZNX™ SCR** catalyst in modules;
2. Internal support structures for catalyst modules (frame);
3. Internally insulated reactor ductwork - with stainless steel liner sheets - to house CO catalyst modules, AIG, and SCR Catalyst modules;
4. Inlet and outlet transition duct sections - internally insulated with stainless steel liner - inlet flow straightener in inlet transition section;
5. Ammonia Injection Grid (AIG);
6. AIG manifold with flow control valves ;
7. NH_3/Air dilution skid: Anhydrous Ammonia to skid;
8. Ambient air cooling system components as required..

BUDGET PRICES: Per Turbine- 3,500 hr/yr	**GE 7EA**	**West. 501D5A**	**West. 501F**
Items 1 - 7 above - complete system	**\$3,600,000**	**\$6,000,000**	**\$5,500,000**
Replacement CO Modules	**\$ 450,000**	**\$ 750,000**	**\$ 500,000** /0.75 = 667,000
Replacement ZNX Modules	**\$1,400,000**	**\$2,000,000**	**\$1,800,000**

Per Turbine- 2,000 hr/yr	**GE 7EA**	**West. 501D5A**	**West. 501F**
Items 1 - 7 above - complete system	**\$3,000,000**	**\$3,600,000**	**\$3,800,000**
Replacement CO Modules	**\$ 360,000**	**\$ 450,000**	**\$ 420,000**
Replacement ZNX Modules	**\$1,000,000**	**\$1,500,000**	**\$1,400,000**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

DOCUMENT / MATERIAL DELIVERY SCHEDULE

Drawings / Documentation - 6 - 8 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details

Operating manuals

Material Delivery 20 - 24 weeks after approval and release for fabrication

---

SYSTEM DESIGN BASIS:

Gas Flow from:	GE Fr7 and Westinghouse 501F - with ambient air cooling
Gas Flow from:	Westinghouse 501D5A
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
CO Concentration (At catalyst face):	See Performance data
CO Reduction:	See Performance data
NOx Concentration (At catalyst face):	See Performance data
NOx Reduction:	See Performance data
NH3 Slip:	5 ppmvd@15%O_2
Pressure Drop through SCR	Nom. 4"WG

ENGELHARD

Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal I
November 13, 1998

Performance Data — **GE 7EA** — **No. Units - 8** — **3,500 hr / yr**

AMBIENT	59	20	80	90	95	90	90	90	90
LOAD	BASE	BASE	BASE	BASE	BASE	BASE	75%	62%	35%
TURBINE EXHAUST TEMPERATURE, F	998	972	1,012	1,019	1,023	1,019	1,080	1,100	1,084
TURBINE EXHAUST FLOW, lb/hr	2,358,000	2,574,000	2,240,000	2,161,000	2,161,000	2,161,000	1,725,000	1,467,000	1,328,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.68	75.45	74.11	73.63	73.18	73.53	73.45	73.57	73.77
O2	13.65	13.89	13.71	13.69	13.60	13.69	13.38	13.71	14.29
CO2	3.16	3.20	3.12	3.10	3.09	3.10	3.19	3.04	2.78
H2O	7.22	6.55	8.18	8.90	9.35	8.90	9.09	8.79	8.27
Ar	0.90	0.91	0.88	0.88	0.88	0.88	0.89	0.89	0.89
AMBIENT AIR FLOW, lb/hr	0	0	0	0	0	0	111,676	129,392	60,909
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	2,358,000	2,574,000	2,240,000	2,181,000	2,161,000	2,161,000	1,836,676	1,596,392	1,388,909
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	74.68	75.45	74.11	73.63	73.18	73.63	73.91	74.18	74.09
O2	13.65	13.89	13.71	13.69	13.50	13.69	13.70	14.12	14.46
CO2	3.16	3.20	3.12	3.10	3.09	3.10	3.00	2.80	2.68
H2O	7.22	6.55	8.18	8.90	9.35	8.90	8.55	8.09	7.91
Ar	0.90	0.91	0.88	0.88	0.88	0.88	0.84	0.82	0.85
CALCULATED AIR + GAS MOL. WT.	28.46	28.54	28.35	28.27	28.22	28.27	28.29	28.32	28.33
GIVEN: TURBINE CO, ppmvd	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
CALC.: TURBINECO, lb/hr	53.5	59.0	50.8	49.2	48.4	49.2	38.8	33.1	30.1
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	42.0
CALC.: TURBINE NOx, lb/hr	53.7	59.5	50.8	49.2	48.6	49.2	40.1	32.6	76.0
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	24.7	24.4	24.7	24.7	24.6	24.7	23.3	24.3	27.2
CALC. NOx, ppmvd@15%O2 - AT CATALYST FACE	15.0	15.0	15.0	15.0	15.0	15.0	14.7	14.5	41.2
FLUE GAS TEMP @ SCR CATALYST, F	998	972	1,012	1,019	1,023	1,019	1,025	1,025	1,025
DESIGN REQUIREMENTS									
CO CATALYST CO OUT, ppmvd@15%O2	7.4	7.3	7.4	7.4	7.4	7.4	7.0	7.3	8.2
SCR CATALYST NOx OUT, ppmvd@15%O2	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	12.4
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.									
GUARANTEED PERFORMANCE DATA									
CO CATALYST CO CONVERSION - % Max.	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
CO OUT, ppmvd@15%O2 - Max.	7.4	8.1	7.4	7.4	7.4	7.4	7.0	7.3	8.2
CO OUT, lb/hr - Max.	16.1	14.8	15.2	14.8	14.5	14.8	11.7	9.9	9.0
CO PRESSURE DROP, 0.6 "WG - Max.									
SCR CATALYST NOx CONVERSION, % - Min.	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
NOx OUT, lb/hr - Max.	16.1	17.9	15.2	14.8	14.6	14.8	12.0	9.7	22.8
NOx OUT, ppmvd@15%O2 - Max.	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	12.4
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	73	81	69	67	66	67	55	46	81
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5	5	5	5

ENGELHARD

Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal
November 13, 1998

Performance Data — **Westinghouse 501D5A** — **No. Units - 4** — **3,500 hr / yr**

AMBIENT	90	90	59	59	90	59
LOAD	BASE	BASE	BASE	BASE	75%	75%
TURBINE EXHAUST TEMPERATURE, F	1,020	1,025	998	1,001	1,050	1,050
TURBINE EXHAUST FLOW, lb/hr	2,911,027	2,859,612	3,112,010	3,072,727	2,341,894	2,440,665
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	70.58	70.67	71.99	72.17	70.98	72.12
O2	12.13	12.27	12.44	12.53	12.39	12.44
CO2	3.42	3.40	3.46	3.44	3.34	3.48
H2O	12.98	12.57	11.21	10.85	12.42	11.06
Ar	0.89	0.89	0.90	0.91	0.89	0.90
AMBIENT AIR FLOW, lb/hr	0	0	0	0	0	0
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	2,911,027	2,853,612	3,112,010	3,072,727	2,341,894	2,440,665
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	70.68	70.67	71.99	72.17	70.86	72.12
O2	12.13	12.27	12.44	12.53	12.39	12.44
CO2	3.42	3.40	3.48	3.44	3.34	3.48
H2O	12.98	12.57	11.21	10.85	12.42	11.06
Ar	0.89	0.89	0.90	0.91	0.89	0.90
CALCULATED AIR + GAS MOL. WT.	27.88	27.90	28.05	28.08	27.91	28.07
GIVEN: TURBINE CO, ppmvd @ 15% O_2	25.0	25.0	25.0	25.0	150.0	150.0
CALC.: TURBINECO, lb/hr	75.1	72.8	80.5	79.0	353.8	380.6
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	25.0	25.0	25.0	25.0	25.0	25.0
CALC.: TURBINE NOx, lb/hr	123.4	119.7	132.3	129.7	96.7	104.2
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	25.0	25.0	25.0	25.0	150.0	150.0
CALC.: NOx, ppmvd@15%O2 - AT CATALYST FACE	25.0	25.0	25.0	25.0	25.0	25.0
FLUE GAS TEMP. @ SCR CATALYST, F	1,020	1,025	998	1,001	1,050	1,050
DESIGN REQUIREMENTS						
CO CATALYST CO OUT, ppmvd@15%O2	7.5	7.5	7.5	7.5	45.0	45.0
SCR CATALYST NOx OUT, ppmvd@15%O2	5.0	5.0	5.0	5.0	5.0	5.0
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.						
GUARANTEED PERFORMANCE DATA						
CO CATALYST CO CONVERSION - % Max.	70.0%	70.0%	70.0%	70.0%	70.0%	70.0%
CO OUT, ppmvd@15%O2 - Max.	7.5	7.5	7.5	7.5	45.0	45.0
CO OUT, lb/hr - Max.	22.5	21.9	24.2	23.7	106.0	114.2
CO PRESSURE DROP, 0.8 "WG - Max.						
SCR CATALYST NOx CONVERSION, % - Min.	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
NOx OUT, lb/hr - Max.	24.7	23.9	26.5	25.9	19.3	20.8
NOx OUT, ppmvd@15%O2 - Max.	5.0	5.0	5.0	5.0	5.0	5.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	163	158	175	171	128	135
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5

ENGELHARD

Simple Cycle Turbines
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal
November 13, 1998

Performance Data | **Westinghouse 501F** | **No. Units - 2** | **3,500 hr / yr**

AMBIENT	110	65	59	0	0	110	65	59	0	0
LOAD	BASE	BASE	BASE	BASE	BASE	75%	75%	75%	75%	75%
FUEL	NG	NG	NG	NG	Oil	NG	NG	NG	NG	Oil
TURBINE EXHAUST TEMPERATURE, F	1,136	1,112	1,108	1,059	1,027	1,160	1,160	1,160	1,103	1,068
TURBINE EXHAUST FLOW, lb/hr	3,268,109	3,477,569	3,524,958	3,506,942	3,680,454	2,740,032	2,792,157	2,813,621	3,135,522	3,185,685
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	72.11	74.08	74.33	75.09	74.94	72.77	74.07	74.31	75.06	74.91
O2	11.61	12.31	12.38	12.44	12.66	12.27	12.31	12.32	12.38	12.55
CO2	3.66	3.87	3.89	3.94	5.08	3.71	3.87	3.90	3.98	5.14
H2O	11.33	8.81	8.50	7.59	6.38	10.34	8.82	8.54	7.88	6.48
Ar	0.90	0.93	0.93	0.94	0.94	0.91	0.93	0.93	0.94	0.94
AMBIENT AIR FLOW, lb/hr	435,941	346,649	333,030	165,534	7,897	444,626	431,749	432,366	262,367	146,948
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	3,704,050	3,824,218	3,857,988	3,672,476	3,688,351	3,184,658	3,223,906	3,245,987	3,397,889	3,332,633
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	73.16	74.72	74.92	75.36	74.96	73.93	75.01	75.22	75.63	75.19
O2	12.61	12.69	12.91	12.72	12.67	13.16	13.17	13.17	12.85	12.89
CO2	3.41	3.62	3.66	3.76	5.07	3.20	3.36	3.39	3.68	4.91
H2O	10.02	8.02	7.78	7.25	6.37	8.92	7.66	7.42	7.07	6.17
Ar	0.80	0.85	0.85	0.90	0.94	0.79	0.81	0.81	0.87	0.90
CALCULATED AIR + GAS MOL. WT.	28.18	28.39	28.42	28.51	28.61	28.28	28.41	28.44	28.52	28.81
GIVEN: TURBINE CO, ppmvd @ 15% O2	15.0	15.0	15.0	15.0	50.0	15.0	15.0	15.0	15.0	50.0
CALC.: TURBINE CO, lb/hr	55.7	58.9	59.8	60.2	209.4	44.8	47.3	47.9	54.4	183.7
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	25.0	25.0	25.0	25.0	42.0	25.0	25.0	25.0	25.0	42.0
CALC.: TURBINE NOx, lb/hr	152.5	161.3	163.7	164.9	288.9	122.8	129.6	131.3	148.8	253.5
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	14.4	14.6	14.6	14.8	50.0	14.3	14.3	14.3	14.6	49.3
CALC.: NOx, ppmvd@15%O2 - AT CATALYST FACE	24.0	24.3	24.3	24.6	42.0	23.8	23.9	23.9	24.4	41.4
FLUE GAS TEMP. @ SCR CATALYST, F	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025
DESIGN REQUIREMENTS										
CO CATALYST CO OUT, ppmvd@15%O2	7.2	7.3	7.3	7.4	25.0	7.1	7.2	7.2	7.3	24.7
SCR CATALYST NOx OUT, ppmvd@15%O2	9.6	9.7	9.7	9.9	16.8	9.5	9.6	9.6	9.8	16.6
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.										
GUARANTEED PERFORMANCE DATA										
CO CATALYST CO CONVERSION - % Max.	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
CO OUT, ppmvd@15%O2 - Max.	7.2	7.3	7.3	7.4	25.0	7.1	7.2	7.2	7.3	24.7
CO OUT, lb/hr - Max.	27.8	29.5	29.9	30.1	104.7	22.4	23.6	24.0	27.2	91.8
CO PRESSURE DROP, 0.8 "WG - Max.										
SCR CATALYST NOx CONVERSION, % - Min.	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
NOx OUT, lb/hr - Max.	61.0	64.5	65.5	65.9	115.6	49.0	51.8	52.5	59.5	101.4
NOx OUT, ppmvd@15%O2 - Max.	9.6	9.7	9.7	9.9	16.8	9.5	9.6	9.6	9.8	16.6
EXPECTED AQUEOUS NH3 (25% SOL.) FLOW, lb/hr	163	'72	174	175	274	131	138	140	158	241
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5	5	5	5	5

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Performance Data — GE 7EA — No. Units - 8 — 2,000 hr / yr

AMBIENT	69	70	80	90	95	90	90	90	90
LOAD	BASE	BASE	BASE	BASE	BASE	BASE	76%	52%	35%
TURBINE EXHAUST TEMPERATURE, F	998	972	1,012	1,019	1,023	1,019	1,060	1,100	1,064
TURBINE EXHAUST FLOW, lb/hr	2,358,000	2,674,000	2,240,000	2,161,000	2,161,000	2,161,000	1,725,000	1,467,000	1,328,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.88	75.45	74.11	73.53	73.18	73.63	73.46	73.67	73.77
O2	13.85	13.89	13.71	13.59	13.60	13.69	13.38	13.71	14.29
CO2	3.16	3.20	3.12	3.10	3.09	3.10	3.19	3.04	2.78
H2O	7.22	6.65	8.18	8.90	9.35	8.90	9.09	8.79	8.27
Ar	0.90	0.91	0.88	0.88	0.88	0.88	0.89	0.89	0.89
AMBIENT AIR FLOW, lb/hr	0	0	0	0	0	0	111,676	129,392	60,909
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	2,358,000	2,674,000	2,240,000	2,161,000	2,161,000	2,161,000	1,836,676	1,596,392	1,388,909
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	74.88	75.45	74.11	73.53	73.18	73.63	73.91	74.18	74.09
O2	13.86	13.89	13.71	13.69	13.60	13.69	13.70	14.12	14.48
CO2	3.16	3.20	3.12	3.10	3.09	3.10	3.00	2.80	2.66
H2O	7.22	6.66	8.18	8.90	9.38	8.90	8.66	8.09	7.91
Ar	0.90	0.91	0.88	0.88	0.88	0.88	0.84	0.82	0.86
CALCULATED AIR + GAS MOL. WT.	28.46	28.64	28.36	28.27	28.22	28.27	28.29	28.32	28.33
GIVEN: TURBINE CO, ppmvd	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
CALC.: TURBINE CO, lb/hr	63.6	69.0	60.6	49.2	48.4	49.2	38.8	33.1	30.1
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	42.0
CALC.: TURBINE NOx, lb/hr	53.7	59.6	50.6	49.2	48.6	49.2	40.1	32.6	76.0
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	24.7	24.4	24.7	24.7	24.8	24.7	23.3	24.3	27.2
CALC.: NOx, ppmvd@15%O2 - AT CATALYST FACE	15.0	15.0	15.0	15.0	15.0	15.0	14.7	14.5	41.2
FLUE GAS TEMP. @ SCR CATALYST, F	998	972	1,012	1,019	1,023	1,019	1,025	1,026	1,025
DESIGN REQUIREMENTS									
CO CATALYST CO OUT, ppmvd@15%O2	12.3	12.2	12.4	12.3	12.3	12.3	11.7	12.2	13.6
SCR CATALYST NOx OUT, ppmvd@15%O2	7.5	7.5	7.5	7.5	7.5	7.5	7.3	7.3	20.6
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.									
GUARANTEED PERFORMANCE DATA									
CO CATALYST CO CONVERSION - % Max.	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
CO OUT, ppmvd@15%O2 - Max.	12.3	12.2	12.4	12.3	12.3	12.3	11.7	12.2	13.6
CO OUT, lb/hr - Max.	26.9	29.5	25.4	24.6	24.2	24.6	19.4	16.6	15.1
CO PRESSURE DROP, 0.5 "WG - Max.									
SCR CATALYST NOx CONVERSION, % - Min.	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
NOx OUT, lb/hr - Max.	26.8	29.8	25.3	24.6	24.3	24.6	20.1	16.2	37.5
NOx OUT, ppmvd@15%O2 - Max.	7.5	7.5	7.5	7.5	7.5	7.5	7.3	7.3	20.6
EXPECTED AQUEOUS NH3 (25% SOL.) FLOW, lb/hr	69	65	56	54	53	54	45	36	61
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5	5	5	5

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2,000 hr / yr

Performance Data	Westinghouse 501D5A				No. Units - 4	
AMBIENT	90	90	59	59	90	59
LOAD	BASE	BASE	BASE	BASE	75%	75%
TURBINE EXHAUST TEMPERATURE, F	1,020	1,025	998	1,001	1,060	1,050
TURBINE EXHAUST FLOW, lb/hr	2,911,027	2,853,512	3,112,010	3,072,727	2,341,894	2,440,885
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	70.58	70.87	71.99	72.17	70.98	72.12
O2	12.13	12.27	12.44	12.63	12.39	12.44
CO2	3.42	3.40	3.48	3.44	3.34	3.48
H2O	12.98	12.57	11.21	10.85	12.42	11.06
Ar	0.89	0.89	0.90	0.91	0.89	0.90
AMBIENT AIR FLOW, lb/hr	0	0	0	0	0	0
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	2,911,027	2,853,512	3,112,010	3,072,727	2,341,894	2,440,885
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	70.58	70.87	71.99	72.17	70.98	72.12
O2	12.13	12.27	12.44	12.63	12.39	12.44
CO2	3.42	3.40	3.48	3.44	3.34	3.48
H2O	12.98	12.57	11.21	10.85	12.42	11.06
Ar	0.89	0.89	0.90	0.91	0.89	0.90
CALCULATED AIR + GAS MOL. WT.	27.88	27.90	28.06	28.08	27.91	28.07
GIVEN: TURBINE CO, ppmvd @ 15% O_2	25.0	25.0	25.0	25.0	150.0	150.0
CALC.: TURBINE CO, lb/hr	75.1	72.8	80.5	79.0	353.3	380.6
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	25.0	25.0	25.0	25.0	25.0	25.0
CALC.: TURBINE NOx, lb/hr	123.4	119.7	132.3	129.7	98.7	104.2
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	25.0	25.0	25.0	25.0	150.0	150.0
CALC.: NOx, ppmvd@15%O2 - AT CATALYST FACE	25.0	25.0	25.0	25.0	25.0	25.0
FLUE GAS TEMP. @ SCR CATALYST, F	1,020	1,025	998	1,001	1,060	1,050
DESIGN REQUIREMENTS						
CO CATALYST CO OUT, ppmvd@15%O2	15.0	15.0	15.0	15.0	90.0	90.0
SCR CATALYST NOx OUT, ppmvd@15%O2	10.0	10.0	10.0	10.0	10.0	10.0
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.						
GUARANTEED PERFORMANCE DATA						
CO CATALYST CO CONVERSION - % Max.	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
CO OUT, ppmvd@15%O2 - Max.	15.0	15.0	15.0	15.0	90.0	90.0
CO OUT, lb/hr - Max.	45.1	43.7	48.3	47.4	212.0	228.3
CO PRESSURE DROP, 0.6 "WG - Max.						
SCR CATALYST NOx CONVERSION, % - Min.	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
NOx OUT, lb/hr - Max.	49.3	47.9	52.9	51.9	39.7	41.7
NOx OUT, ppmvd@15%O2 - Max.	10.0	10.0	10.0	10.0	10.0	10.0
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	130	126	140	137	102	110
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5

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Performance Data — Westinghouse 501F — No. Units - 2 — 2,000 hr / yr

AMBIENT	110	65	59	0	0	110	65	59	0	0
LOAD	BASE	BASE	BASE	BASE	BASE	75%	75%	75%	75%	75%
FUEL	NG	NG	NG	NG	Oil	NG	NG	NG	NG	Oil
TURBINE EXHAUST TEMPERATURE, F	1,136	1,112	1,108	1,069	1,027	1,160	1,160	1,160	1,103	1,068
TURBINE EXHAUST FLOW, lb/hr	3,268,109	3,477,669	3,524,956	3,506,942	3,660,454	2,740,032	2,792,157	2,813,621	3,135,622	3,185,686
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	72.11	74.06	74.33	75.09	74.94	72.77	74.07	74.31	75.06	74.91
O2	11.61	12.31	12.36	12.44	12.66	12.27	12.31	12.32	12.36	12.65
CO2	3.65	3.67	3.66	3.94	6.06	3.71	3.87	3.90	3.88	6.14
H2O	11.33	8.61	8.50	7.59	6.36	10.34	8.82	8.54	7.66	6.46
Ar	0.90	0.93	0.93	0.94	0.94	0.91	0.93	0.93	0.94	0.94
AMBIENT AIR FLOW, lb/hr	435,941	346,549	333,030	165,534	7,897	444,526	431,749	432,366	262,367	146,946
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	3,704,050	3,824,218	3,857,986	3,672,476	3,668,351	3,184,558	3,223,906	3,245,987	3,397,989	3,332,633
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	73.16	74.72	74.92	75.36	74.96	75.93	75.01	75.22	75.63	75.10
O2	12.61	12.69	12.91	12.72	12.67	13.16	13.17	13.17	12.65	12.63
CO2	3.41	3.52	3.55	3.76	6.07	3.20	3.36	3.39	3.68	4.91
H2O	10.02	8.02	7.76	7.25	6.37	6.92	7.65	7.42	7.07	6.17
Ar	0.80	0.86	0.86	0.90	0.94	0.79	0.81	0.81	0.87	0.90
CALCULATED AIR + GAS MOL. WT.	28.16	28.30	28.42	28.51	28.61	28.20	28.41	28.44	28.52	28.61
GIVEN: TURBINE CO, ppmvd @ 15% O2	15.0	15.0	15.0	15.0	50.0	15.0	15.0	15.0	15.0	50.0
CALC.: TURBINE CO, lb/hr	55.7	58.9	59.6	60.2	209.4	44.8	47.8	47.9	54.4	163.7
GIVEN: TURBINE NOx, ppmvd @ 15% O2	25.0	25.0	25.0	25.0	42.0	25.0	25.0	25.0	25.0	42.0
CALC.: TURBINE NOx, lb/hr	152.5	161.3	163.7	164.9	286.9	122.6	129.5	131.5	146.6	253.6
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	14.4	14.6	14.8	14.8	50.0	14.3	14.3	14.3	14.6	49.3
CALC.: NOx, ppmvd@15%O2 - AT CATALYST FACE	24.0	24.3	24.3	24.6	42.0	23.6	23.9	23.9	24.4	41.4
FLUE GAS TEMP. @ SCR CATALYST, F	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025	1,025
DESIGN REQUIREMENTS										
CO CATALYST — CO OUT, ppmvd@15%O2	10.1	10.2	10.2	10.4	35.0	10.0	10.0	10.0	10.2	34.5
SCR CATALYST — NOx OUT, ppmvd@15%O2	14.4	14.8	14.6	14.8	25.2	14.3	14.3	14.3	14.6	24.9
NH3 SLIP, ppmvd@15%O2	5	5	5	5	5	5	5	5	5	5
CO and SCR PRESSURE DROP, 4.0 "WG - Max.										
GUARANTEED PERFORMANCE DATA										
CO CATALYST — CO CONVERSION - % Max.	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
CO OUT, ppmvd@15%O2 - Max.	10.1	10.2	10.2	10.4	35.0	10.0	10.0	10.0	10.2	34.5
CO OUT, lb/hr - Max.	39.0	41.2	41.6	42.2	146.6	31.3	33.1	33.6	38.0	128.6
CO PRESSURE DROP, 0.6 "WG - Max.										
SCR CATALYST — NOx CONVERSION, % - Min.	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
NOx OUT, lb/hr - Max.	91.5	96.8	98.2	98.9	173.4	73.6	77.7	78.8	89.3	152.1
NOx OUT, ppmvd@15%O2 - Max.	14.4	14.6	14.6	14.8	25.2	14.3	14.3	14.3	14.6	24.9
EXPECTED AQUEOUS NH3 (25% SOL.) FLOW, lb/hr	122	129	131	131	198	99	104	106	119	174
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5	5	5	5	5	5	5

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The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

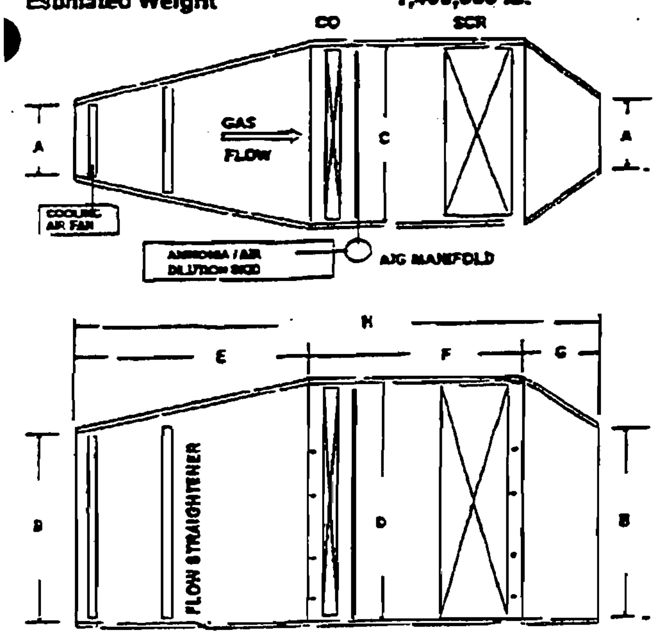
Assumed Dimensions / Sketch:

GE7EA 3,500 hr/yr

Turbine Discharge Width	(A)	15'-0"
Turbine Discharge Height	(B)	15'-0"
Reactor Inside Liner Width	(C)	41'-6"
Reactor Inside Liner Height	(D)	32'-3"
Inlet Transition Length	(E)	31'-0"
Reactor Depth	(F)	15'-0"
Outlet Transition Length	(G)	13'-3"
Total Depth	(H)	59'-3"
Estimated Weight		1,100,00 lb.

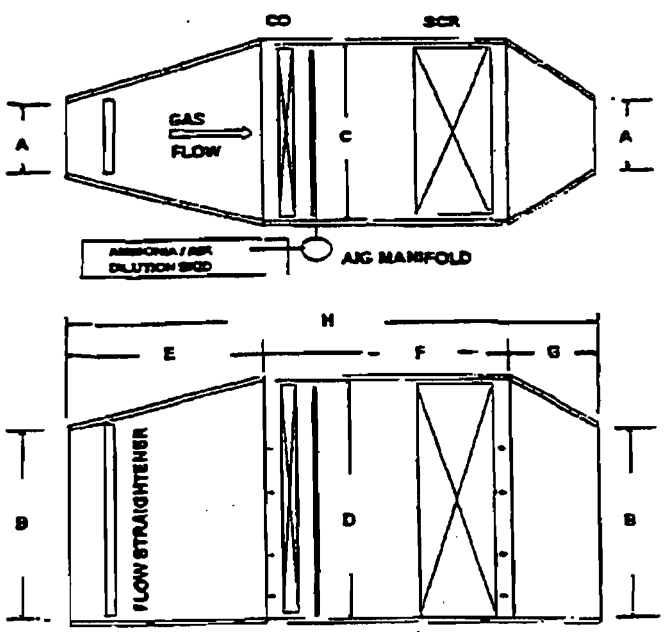
West. 501F 3,500 hr/yr

Turbine Discharge Width	(A)	15'-0"
Turbine Discharge Height	(B)	15'-0"
Reactor Inside Liner Width	(C)	55'-6"
Reactor Inside Liner Height	(D)	35'-6"
Inlet Transition Length	(E)	36'-3"
Reactor Depth	(F)	15'-0"
Outlet Transition Length	(G)	20'-3"
Total Depth	(H)	71'-6"
Estimated Weight		1,400,000 lb.



West. 501D5A 3,500 hr/yr

Turbine Discharge Width	(A)	15'-0"
Turbine Discharge Height	(B)	15'-0"
Reactor Inside Liner Width	(C)	58'-3"
Reactor Inside Liner Height	(D)	35'-6"
Inlet Transition Length	(E)	38'-6"
Reactor Depth	(F)	15'-0"
Outlet Transition Length	(G)	21'-6"
Total Depth	(H)	75'-0"
Estimated Weight		1,400,000 lb.



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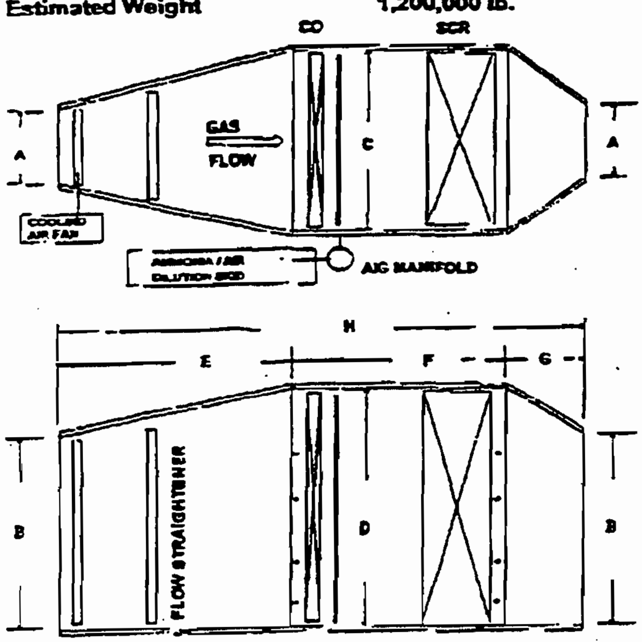
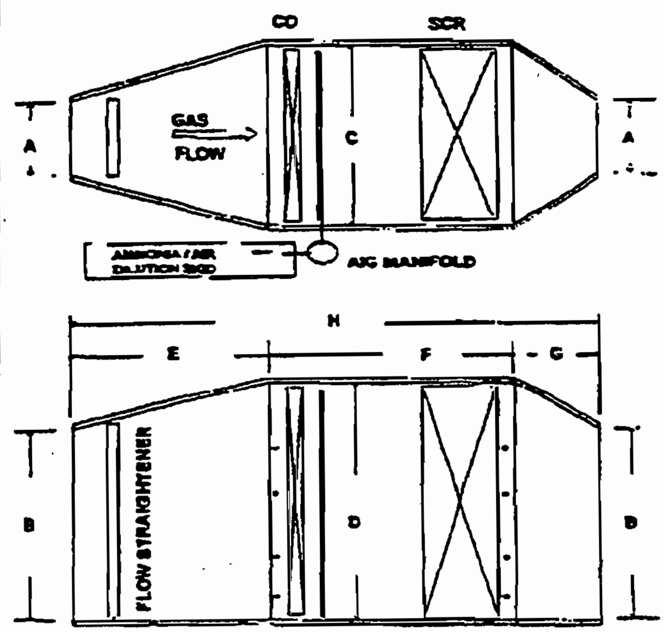
<u>GE7EA</u>	2,000 hr/yr
Turbine Discharge Width	(A) 15'-0"
Turbine Discharge Height	(B) 15'-0"
Reactor Inside Liner Width	(C) 39'-6"
Reactor Inside Liner Height	(D) 29'-0"
Inlet Transition Length	(E) 25'-6"
Reactor Depth	(F) 15'-0"
Outlet Transition Length	(G) 12'-3"
Total Depth	(H) 52'-9"
Estimated Weight	1,000,00 lb.

<u>West. 501F</u>	2,000 hr/yr
Turbine Discharge Width	(A) 15'-0"
Turbine Discharge Height	(B) 15'-0"
Reactor Inside Liner Width	(C) 51'-0"
Reactor Inside Liner Height	(D) 32'-3"
Inlet Transition Length	(E) 32'-0"
Reactor Depth	(F) 15'-0"
Outlet Transition Length	(G) 18'-0"
Total Depth	(H) 65'-0"
Estimated Weight	1,200,000 lb.



<u>West. 501D5A</u>	2,000 hr/yr
Turbine Discharge Width	(A) 15'-0"
Turbine Discharge Height	(B) 15'-0"
Reactor Inside Liner Width	(C) 47'-9"
Reactor Inside Liner Height	(D) 32'-3"
Inlet Transition Length	(E) 30'-9"
Reactor Depth	(F) 15'-0"
Outlet Transition Length	(G) 16'-6"
Total Depth	(H) 62'-3"
Estimated Weight	1,100,000 lb.



<u>Excluded from Scope of Supply:</u>
Ammonia storage and pumping
Electrical grounding equipment
Foundations
All other items not specifically listed in <u>Scope of Supply</u>
Any interconnecting field piping or wiring
Utilities
All Monitors

APPENDIX D

BPIP MODEL OUTPUT FILE

BPIP (Dated: 95086)

DATE : 10/24/ 0
TIME : 8:14:43
C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

The UTMP variable is set to UTMY. The input is assumed to be in UTM coordinates. BPIP will move the UTM origin to the first pair of UTM coordinates read. The UTM coordinates of the new origin will be subtracted from all the other UTM coordinates entered to form this new local coordinate system.

Plant north is set to 0.00 degrees with respect to True North.

C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
STCK1	24.38	0.00	41.15	65.00
STCK2	24.38	0.00	41.15	65.00
STCK3	24.38	0.00	41.15	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

BPIP (Dated: 95086)

DATE : 10/24/ 0

TIME : 8:14:43

C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

BPIP output is in meters

```
SO BUILDHGT STCK1        8.23     8.23     8.23     8.23     8.23     8.23
SO BUILDHGT STCK1       13.72    13.72    13.72    13.72    13.72     8.23
SO BUILDHGT STCK1        8.23     8.23     8.23     8.23     8.23     8.23
SO BUILDHGT STCK1        8.23     8.23     8.23     8.23     8.23     8.23
SO BUILDHGT STCK1       16.46    16.46    16.46    16.46    16.46    16.46
SO BUILDHGT STCK1       16.46    16.46    16.46     8.23     8.23     8.23
SO BUILDWID STCK1       20.84    21.37    21.25    20.48    19.09    17.12
SO BUILDWID STCK1       18.53    15.68    14.31    15.68    17.84    17.12
SO BUILDWID STCK1       19.09    20.48    21.25    21.37    20.84    19.68
SO BUILDWID STCK1       20.84    21.37    21.25    20.48    19.09    17.12
SO BUILDWID STCK1       16.57    15.68    14.31    15.68    16.57    16.79
SO BUILDWID STCK1       16.69    16.63    15.52    21.37    20.84    19.68

SO BUILDHGT STCK2        8.23    14.67    14.67    14.67    14.67    14.67
SO BUILDHGT STCK2       13.72    13.72    13.72    13.72    13.72     8.23
SO BUILDHGT STCK2        8.23     8.23     8.23     8.23     8.23     0.00
SO BUILDHGT STCK2        8.23     8.23    13.72    16.46    16.46    16.46
SO BUILDHGT STCK2       16.46    16.46    16.46    16.46    16.46    16.46
SO BUILDHGT STCK2       16.46    16.46    13.75     8.23     8.23     0.00
SO BUILDWID STCK2       21.29    57.40    58.82    60.67    60.67    58.82
SO BUILDWID STCK2       18.07    15.48    14.11    15.48    18.13    17.36
SO BUILDWID STCK2       19.39    20.84    21.65    21.80    21.29     0.00
SO BUILDWID STCK2       20.84    21.37    16.12    16.20    16.84    16.96
SO BUILDWID STCK2       16.39    15.48    14.11    15.48    16.39    17.34
SO BUILDWID STCK2       17.25    16.63    15.03    21.80    21.29     0.00

SO BUILDHGT STCK3        8.23     8.23    14.67    14.67    14.67    14.67
SO BUILDHGT STCK3       14.67    14.67    14.67    13.75    13.75     8.23
SO BUILDHGT STCK3        8.23     8.23     8.23     8.23     8.23     0.00
SO BUILDHGT STCK3        8.23     8.23    14.67    16.46    16.46    16.46
SO BUILDHGT STCK3       16.46    16.46    16.46    16.46    16.46     8.23
SO BUILDHGT STCK3        8.23    13.72    13.72    13.72    13.72     0.00
SO BUILDWID STCK3       21.67    22.08    58.82    60.67    60.67    58.82
SO BUILDWID STCK3       57.40    60.16    61.08    15.95    17.98    17.19
SO BUILDWID STCK3       19.33    20.89    21.82    22.08    21.67     0.00
SO BUILDWID STCK3       21.29    21.80    58.82    16.07    16.69    16.79
SO BUILDWID STCK3       16.90    15.95    14.51    15.95    16.90    17.19
SO BUILDWID STCK3       19.33    39.62    41.31    41.74    40.90     0.00
```

BPIP (Dated: 95086)

DATE : 10/24/ 0
TIME : 8:14:43
C:\ISCView3\projects\Enron\Enron Midway\midgep.bpv

============================
BPIP PROCESSING INFORMATION:
============================

The ST flag has been set for processing for an ISCST2 run.

Inputs entered in Meters will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

The UTMP variable is set to UTMY. The input is assumed to be in UTM coordinates. BPIP will move the UTM origin to the first pair of UTM coordinates read. The UTM coordinates of the new origin will be subtracted from all the other UTM coordinates entered to form this new local coordinate system.

The new local coordinates will be displayed in parentheses just below the UTM coordinates they represent.

Plant north is set to 0.00 degrees with respect to True North.

==============
INPUT SUMMARY:
==============

Number of buildings to be processed : 16

EXHDUCT1 has 1 tier(s) with a base elevation of 0.00 Meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER COORDINATES X	Y
EXHDUCT1	1	1	8.23	4		
					556674.30	3028588.23 meters
					(0.00	0.00) meters
					556693.98	3028588.23 meters
					(19.68	0.00) meters
					556693.98	3028579.82 meters
					(19.68	-8.41) meters
					556674.30	3028579.82 meters
					(0.00	-8.41) meters

EXHDUCT2 has 1 tier(s) with a base elevation of 0.00 Meters

BUILDING NAME	TIER NUMBER	BLDG-TIER NUMBER	TIER HEIGHT	NO. OF CORNERS	CORNER COORDINATES X	Y
EXHDUCT2	1	5	8.23	4		
					556674.30	3028552.00 meters

```
                                           (        0.00       -36.24) meters
                                               556694.44   3028552.00 meters
                                           (       20.14       -36.24) meters
                                               556694.44   3028543.58 meters
                                           (       20.14       -44.65) meters
                                               556674.30   3028543.58 meters
                                           (        0.00       -44.65) meters


EXHDUCT3 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

EXHDUCT3    1        9      8.23      4
                                               556674.30   3028515.29 meters
                                           (        0.00       -72.94) meters
                                               556694.91   3028515.29 meters
                                           (       20.60       -72.94) meters
                                               556694.91   3028507.34 meters
                                           (       20.60       -80.89) meters
                                               556674.30   3028507.34 meters
                                           (        0.00       -80.89) meters


TURBENC2 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

TURBENC2    1       13     13.72      4
                                               556694.51   3028551.33 meters
                                           (       20.21       -36.90) meters
                                               556708.22   3028551.33 meters
                                           (       33.92       -36.90) meters
                                               556708.22   3028543.65 meters
                                           (       33.92       -44.59) meters
                                               556694.51   3028543.65 meters
                                           (       20.21       -44.59) meters


TURBENC3 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

TURBENC3    1       17     13.75      4
                                               556694.91   3028514.83 meters
                                           (       20.60       -73.40) meters
                                               556708.09   3028514.83 meters
                                           (       33.79       -73.40) meters
                                               556708.09   3028507.61 meters
                                           (       33.79       -80.63) meters
                                               556694.91   3028507.61 meters
                                           (       20.60       -80.63) meters


AIRINT2  has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y
```

```
AIRINT2      1        21      16.46      4
                                                    556708.36  3028554.58 meters
                                          (             34.05      -33.65) meters
                                                    556717.50  3028554.58 meters
                                          (             43.19      -33.65) meters
                                                    556717.50  3028540.47 meters
                                          (             43.19      -47.77) meters
                                                    556708.36  3028540.47 meters
                                          (             34.05      -47.77) meters

TURBENC1 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

TURBENC1     1        25      13.72      4
                                                    556694.05  3028588.17 meters
                                          (             19.74       -0.07) meters
                                                    556708.49  3028588.17 meters
                                          (             34.19       -0.07) meters
                                                    556708.49  3028580.95 meters
                                          (             34.19       -7.29) meters
                                                    556694.05  3028580.95 meters
                                          (             19.74       -7.29) meters

AIRINT1  has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

AIRINT1      1        29      16.46      4
                                                    556708.49  3028591.35 meters
                                          (             34.19        3.11) meters
                                                    556717.63  3028591.35 meters
                                          (             43.33        3.11) meters
                                                    556717.63  3028577.04 meters
                                          (             43.33      -11.20) meters
                                                    556708.49  3028577.04 meters
                                          (             34.19      -11.20) meters

AIRINT3  has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X           Y

AIRINT3      1        33      16.46      4
                                                    556708.09  3028518.47 meters
                                          (             33.79      -69.76) meters
                                                    556717.63  3028518.47 meters
                                          (             43.33      -69.76) meters
                                                    556717.63  3028503.96 meters
                                          (             43.33      -84.27) meters
                                                    556708.09  3028503.96 meters
                                          (             33.79      -84.27) meters
```

```
WATERTNK has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

WATERTNK    1        37     14.63      8
                                               556808.00  3028493.70 meters
                                          (       133.69       -94.54) meters
                                               556804.95  3028486.48 meters
                                          (       130.65      -101.76) meters
                                               556797.73  3028483.43 meters
                                          (       123.42      -104.81) meters
                                               556790.51  3028486.48 meters
                                          (       116.20      -101.76) meters
                                               556787.46  3028493.70 meters
                                          (       113.15       -94.54) meters
                                               556790.51  3028500.92 meters
                                          (       116.20       -87.32) meters
                                               556797.73  3028503.96 meters
                                          (       123.42       -84.27) meters
                                               556804.95  3028500.92 meters
                                          (       130.65       -87.32) meters

FUELSTNK has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

FUELSTNK    1        41     14.63      8
                                               556819.59  3028435.46 meters
                                          (       145.29      -152.77) meters
                                               556814.89  3028424.27 meters
                                          (       140.58      -163.97) meters
                                               556803.69  3028419.56 meters
                                          (       129.39      -168.67) meters
                                               556792.49  3028424.27 meters
                                          (       118.19      -163.97) meters
                                               556787.79  3028435.46 meters
                                          (       113.49      -152.77) meters
                                               556792.49  3028446.66 meters
                                          (       118.19      -141.58) meters
                                               556803.69  3028451.36 meters
                                          (       129.39      -136.87) meters
                                               556814.89  3028446.66 meters
                                          (       140.58      -141.58) meters

FUELDTNK has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

FUELDTNK    1        45     12.19      8
                                               556771.82  3028436.59 meters
                                          (        97.52      -151.65) meters
                                               556769.31  3028430.56 meters
                                          (        95.00      -157.68) meters
                                               556763.28  3028428.04 meters
                                          (        88.97      -160.19) meters
```

```
                                                    556757.25  3028430.56 meters
                                               (        82.94     -157.68) meters
                                                    556754.73  3028436.59 meters
                                               (        80.43     -151.65) meters
                                                    556757.25  3028442.62 meters
                                               (        82.94     -145.62) meters
                                                    556763.28  3028445.13 meters
                                               (        88.97     -143.10) meters
                                                    556769.31  3028442.62 meters
                                               (        95.00     -145.62) meters


CTRLBLNG has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

CTRLBLNG    1       49     13.72     4
                                                    556684.04  3028456.27 meters
                                               (         9.74     -131.97) meters
                                                    556722.86  3028456.27 meters
                                               (        48.56     -131.97) meters
                                                    556722.86  3028440.90 meters
                                               (        48.56     -147.34) meters
                                                    556684.04  3028440.90 meters
                                               (         9.74     -147.34) meters


BLDG14   has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

BLDG14      1       53     14.67     8
                                                    556645.02  3028476.80 meters
                                               (       -29.28     -111.43) meters
                                                    556636.01  3028455.27 meters
                                               (       -38.29     -132.96) meters
                                                    556614.48  3028446.26 meters
                                               (       -59.82     -141.97) meters
                                                    556592.95  3028455.27 meters
                                               (       -81.36     -132.96) meters
                                                    556583.94  3028476.80 meters
                                               (       -90.36     -111.43) meters
                                                    556592.95  3028498.33 meters
                                               (       -81.36      -89.90) meters
                                                    556614.48  3028507.34 meters
                                               (       -59.82      -80.89) meters
                                                    556636.01  3028498.33 meters
                                               (       -38.29      -89.90) meters


CHILLER1 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER   NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

CHILLER1    1       57      2.44     4
                                                    556584.27  3028617.65 meters
                                               (       -90.03       29.42) meters
```

```
                                              556600.70  3028617.65 meters
                                          (      -73.60        29.42) meters
                                              556600.70  3028521.19 meters
                                          (      -73.60       -67.04) meters
                                              556584.27  3028521.19 meters
                                          (      -90.03       -67.04) meters


CHILLER2 has 1 tier(s) with a base elevation of    0.00 Meters
BUILDING  TIER  BLDG-TIER  TIER    NO. OF      CORNER   COORDINATES
  NAME   NUMBER   NUMBER  HEIGHT  CORNERS        X            Y

CHILLER2    1       61      2.44     4
                                              556608.78  3028617.32 meters
                                          (      -65.52        29.08) meters
                                              556626.21  3028617.32 meters
                                          (      -48.10        29.08) meters
                                              556626.21  3028587.51 meters
                                          (      -48.10        -0.73) meters
                                              556608.78  3028587.51 meters
                                          (      -65.52        -0.73) meters

Number of stacks to be processed :    3

                   STACK             STACK   COORDINATES
 STACK NAME      BASE  HEIGHT          X          Y

 STCK1           0.00   24.38 Meters
                                   556670.26  3028584.26 meters
                             (        -4.04       -3.97) meters
 STCK2           0.00   24.38 Meters
                                   556670.06  3028547.82 meters
                             (        -4.24      -40.42) meters
 STCK3           0.00   24.38 Meters
                                   556670.06  3028511.32 meters
                             (        -4.24      -76.92) meters

   No stacks have been detected as being atop any structures.


                    Overall GEP Summary Table
                         (Units: meters)


StkNo:  1  Stk Name:STCK1    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   16.47              *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  314.50
  Bldg-Tier nos. contributing to GEP:  21


StkNo:  2  Stk Name:STCK2    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:   16.46              *Eqn1 Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  223.25
  Bldg-Tier nos. contributing to GEP:  29
```

```
StkNo:  3  Stk Name:STCK3    Stk Ht:  24.38 Prelim. GEP Stk.Ht:   65.00
           GEP:  BH:  16.46  PBW:    16.47             *Eqnl Ht:   41.15
         *adjusted for a Stack-Building elevation difference of    0.00
 No. of Tiers affecting Stk:  1  Direction occurred:  225.50
  Bldg-Tier nos. contributing to GEP:  21
```

APPENDIX E

DETAILED ISCST3 MODELING RESULTS

ISCST3 Model Resultsfor the Proposed Combustion Turbines

Table E-1 Distillate Oil

DistillateOil - Class II Receptors								
	Normalized Concentration ($\mu g/m^3$ per g/sec)*						Location	
100% Load	**1987**	**1988**	**1989**	**1990**	**1991**	**Maximum**	**UTM X**	**UTM Y**
1-Hr	0.5219	0.62008	0.571	0.63242	0.4234	0.632	555670	3029848.0
3-Hr	0.2571	0.25993	0.24	0.24747	0.2636	0.264	562670	3012548.0
8-Hr	0.13872	0.15639	0.1494	0.14115	0.1245	0.156	538670	3024548.0
24-hr	0.05595	0.05553	0.0527	0.06462	0.0515	0.065	540670	3038548.0
Annual	0.00435	0.00441	0.0047	0.0047	0.0048	0.005	547670	3033548.0
75% Load	**1987**	**1988**	**1989**	**1990**	**1991**	**Maximum**	**UTM X**	**UTM Y**
1-Hr	1.22439	0.6363	0.5868	0.71752	1.5901	1.590	556770	3028648.0
3-Hr	0.40813	0.29918	0.2802	0.28341	0.53	0.530	556770	3028648.0
8-Hr	0.16111	0.1804	0.1742	0.15719	0.2897	0.290	556730.56	3028620.5
24-hr	0.07015	0.06893	0.0617	0.07387	0.0966	0.097	556730.56	3028620.5
Annual	0.0051	0.00519	0.0056	0.00543	0.0057	0.006	547670	3033548.0
50% Load	**1987**	**1988**	**1989**	**1990**	**1991**	**Maximum**	**UTM X**	**UTM Y**
1-Hr	1.42526	0.98102	0.8377	0.84463	1.8415	1.842	556770	3028648.0
3-Hr	0.47509	0.33903	0.3213	0.32084	0.6874	0.687	556470	3028548.0
8-Hr	0.23613	0.20455	0.1994	0.2076	0.3416	0.342	556730.56	3028620.5
24-hr	0.07871	0.07947	0.0712	0.08313	0.1385	0.138	556580.94	3028572.5
Annual	0.00575	0.00599	0.0063	0.0062	0.0065	0.006	547670	3033548.0
* Based on 1 g/sec for each turbine stack (3)								

ISCST3 Model Resultsfor the Proposed Combustion Turbines

Table E-2 Natural Gas

Natural Gas - Class II Receptors								
Normalized Concentration ($\mu g/m^3$ per g/sec)*							Location	
100% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	0.524	0.622	0.573	0.634	0.432	0.634	555670	3029848.0
3-Hr	0.261	0.264	0.244	0.251	0.269	0.269	562670	3012548.0
8-Hr	0.142	0.159	0.152	0.142	0.126	0.159	538670	3024548.0
24-hr	0.057	0.060	0.054	0.066	0.052	0.066	540670	3038548.0
Annual	0.00442	0.0045	0.0049	0.00477	0.00491	0.005	547670	3033548.0
75% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	1.253	0.639	0.589	0.720	1.626	1.626	556770	3028648.0
3-Hr	0.418	0.305	0.286	0.289	0.542	0.542	556770	3028648.0
8-Hr	0.166	0.184	0.178	0.160	0.296	0.296	556730.56	3028620.5
24-hr	0.071	0.070	0.063	0.075	0.099	0.099	556730.56	3028620.5
Annual	0.00516	0.00528	0.0057	0.0055	0.00575	0.006	547670	3033548.0
50% Load	1987	1988	1989	1990	1991	Maximum	UTM X	UTM Y
1-Hr	1.459	1.006	0.840	0.847	1.883	1.883	556770	3028648.0
3-Hr	0.486	0.345	0.328	0.327	0.705	0.705	556470	3028548.0
8-Hr	0.242	0.208	0.203	0.213	0.350	0.350	556730.56	3028620.5
24-hr	0.081	0.081	0.073	0.085	0.142	0.142	556580.94	3028572.5
Annual	0.00589	0.00612	0.0064	0.00636	0.00665	0.007	547670	3033548.0
* Based on 1 g/sec for each turbine stack (3)								

APPENDIX F

KEY TO ISCST3 MODELING FILES ON CD-ROM

10/31/00

Key to files on CDROM - Midway Energy, L.L.C. Florida

- *Directory :\Midway\GEP-BPIP - contains BPIP input and output files*

File Naming Convention:

Midgep.bpi - BPIP input file
Midgep.sum - BPIP input summary
Midgep.bpo - BPIP output file

- *Directory :\Midway\ISCST3\Natural Gas - contains ISCST3 input and output files for Natural Gas* modeled with an emission rate of 1 g/sec.

File Naming Convention:

NG10087 - Natural Gas with turbines at 100% load with 1987 metdata, repeat for '88, '89, '90 and '91
NG07587 - Natural Gas with turbines at 75% load with 1987 metdata, repeat for '88, '89, '90 and '91
NG05087 - Natural Gas with turbines at 50% load with 1987 metdata, repeat for '88, '89, '90 and '91

- *Directory :\Midway\ISCST3\Distillate Oil - contains ISCST3 input and output files for Distillate Oil modeled with an emission rate of 1 g/sec.*

File Naming Convention:

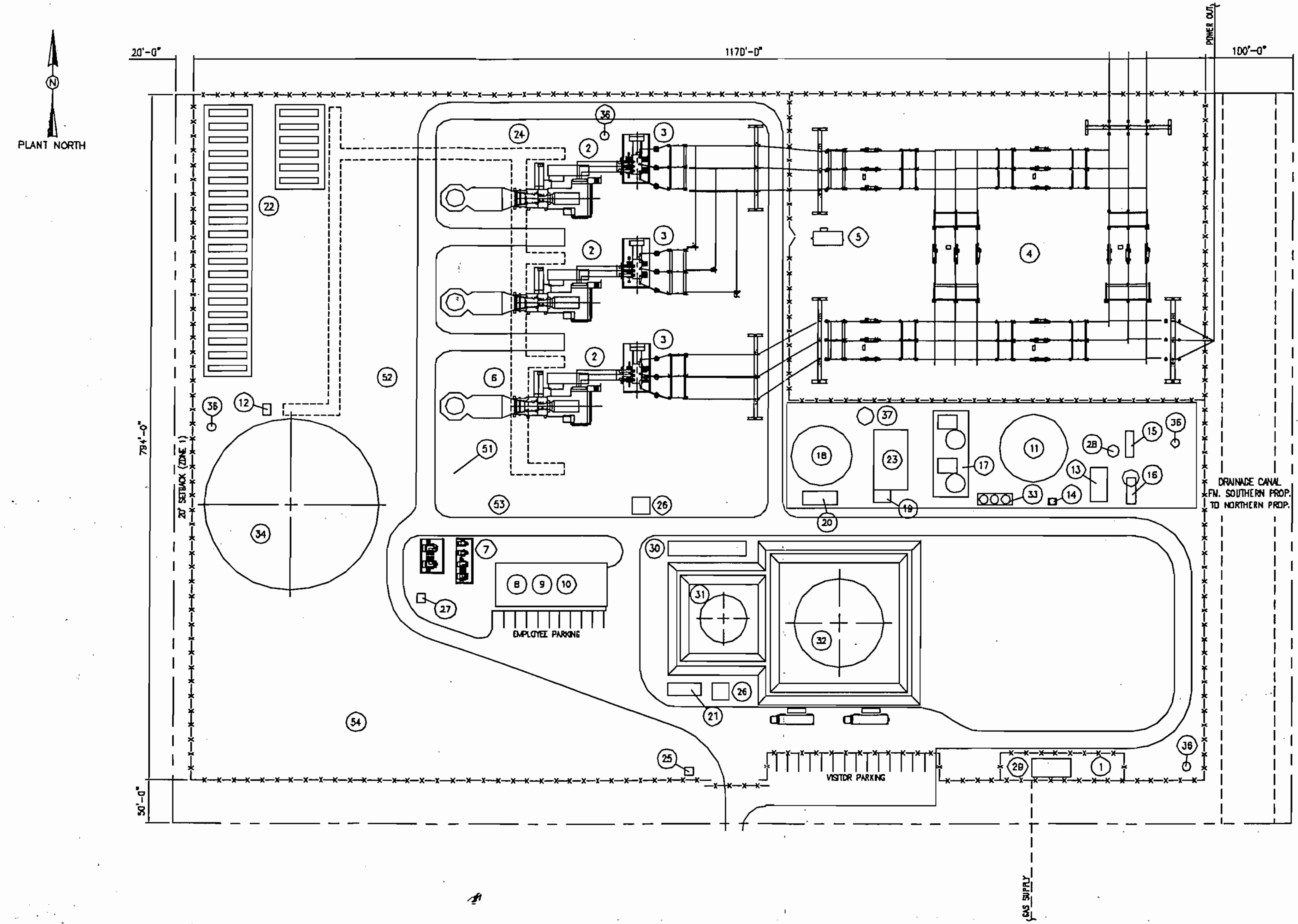
OI10087 - Distillate Oil with turbines at 100% load with 1987 metdata, repeat for '88, '89, '90 and '91
OI07587 - Distillate Oil with turbines at 75% load with 1987 metdata, repeat for '88, '89, '90 and '91
OI05087 - Distillate Oil with turbines at 50% load with 1987 metdata, repeat for '88, '89, '90 and '91

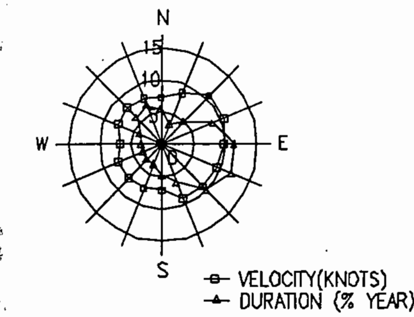
- *Directory :\Midway\metdata - contains five years ISCST3 meteorological data, 1987-1991, West Palm Beach International Airport*

File Naming Convention:

12844-87 - 1987 meteorological data, repeat for '88,'89,'90 and '91

****





WIND ROSE

SCHEDULE OF COMPONENTS	
1	GAS RECEIVING/METERING
2	GAS TURBINE/GENERATOR
3	MAIN STEP-UP TRANSFORMER
4	SUBSTATION
5	SUBSTATION CONTROL ROOM
6	EXHAUST STACK
7	PLANT SWITCHGEAR/MCC AREA
8	ELECTRICAL ROOM BUILDING
9	CONTROL ROOM/MAINTENANCE/STORAGE BLDG.
10	ADMINISTRATION BUILDING (2 STORIES)
11	FILTERED WATER (23,810 BBL)
12	FIRE WATER PUMP HOUSE
13	PACKAGE BOILER
14	AERATION TOWER
15	SPRAY DRYER (EQUIPMENT SKID)
16	SPRAY DRYER AND SOLIDS DUMPSTER
17	BRINE CONCENTRATOR
18	DEMINERALIZED WATER TANK (22,830 BBL)
19	LABORATORY
20	CHEMICAL STORAGE
21	OIL DRUM STORAGE
22	AIR COOLED CHILLER
23	POLISHER BUILDING (70'x40')
24	PIPE/CABLE WAY
25	GUARD HOUSE
26	OILY WATER SUMP (TWO)
27	SEWAGE TREATMENT
28	FILTER BACKWASH SETTLING TANK
29	FUEL GAS COMPRESSOR ENCLOSURE
30	FUEL TREATMENT/FORWARDING EQUIPMENT
31	FUEL OIL DAY TANK (14,700 BBL)
32	FUEL OIL STORAGE (58,800 BBL)
33	FILTER SKID
34	CHILLER WATER TANK (267,000 BBL)
35	STORMWATER RETENTION POND (LOCATED NORTH OF PLANT PERIMETER. EXACT LOCATION TO BE DETERMINED LATER)
36	WATER WELL (FOUR)
37	POLISHER FEED TANK (4780 BBL)

COMBINED (8, 9, 10)

CONCEPTUAL

60 0 60 120 180 240
FEET

DWG. NO.	REFERENCE DRAWING TITLE	NO.	REVISION - DESCRIPTION	BY	DATE	CHK'D	APP'D
		C	GENERAL REVISIONS	JDG	10/19/00		
		B	GENERAL REVISION	WW	10/12/00		
		A	ISSUED PRELIMINARY	JDD	08/25/00		

DWG. STATUS	CHECKED BY	CHECKED DATE	APPROVED BY	APPROVED DATE	APPROVED BY	APPROVED DATE
PREL'Y						
BID						
CONSTR.						
CADDS	PLOT DATE: 10/19/2000 - 13:33					
	FILE NAME: 531M3381.DWG					

P.L./STA. ACCT. NO.
CONSTRUCTION YR

	BY	DATE
DESIGN		
DRAWN	ESE	8/00
ASBUILT		

FILE NO. -531M3381M.DWG
SCALE 1"=80'-0" @ 34"x22"

ENRON
Enron Engineering & Construction Co.

FIGURE 1-2
MIDWAY ENERGY CENTER
(3) GE 7FA SIMPLE CYCLE
PLOT PLAN
ST. LUCIE COUNTY, FLORIDA

AFC/WORK ORDER
ASBUILT DWG. NO.
CONSTRUCTION DWG. NO. M3-03-B
SHEET 1 OF 1
REV. NO. C