

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Oleander Power Project, L.P.

Oleander Power Project Units 1-5
Five 190 Megawatt Combustion Turbines
Cocoa, Brevard County

DEP File No. 0090180-001-AC
PSD-FL-258

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

March 26, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Oleander Power Project
250 West Pratt Street, 23rd Floor
Baltimore, MD 21201

Authorized Representative: Mr. Richard L. Wolfinger, Vice President

1.2 Reviewing and Process Schedule

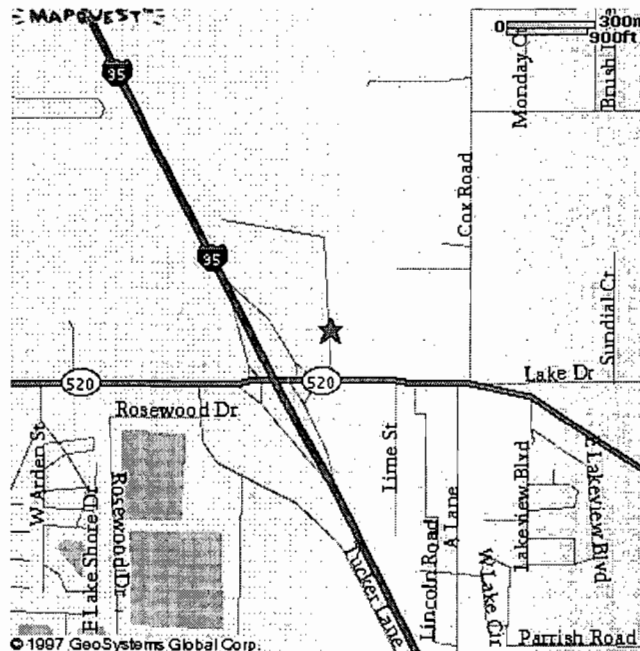
11-24-98: Date of Receipt of Application
12-17-98: DEP Incompleteness Letter
12-22-98: DEP Incompleteness Letter
02-02-99: Received Oleander Response to Incompleteness Letters
03-19-99: Received Oleander Revision to Application
03-26-99: Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location

The Oleander Power Project is located at 527 Townsend Road in Cocoa, Brevard County (See Figure 1). This site is approximately 180 kilometers from the Chassahowitzka National Wilderness Area, a Class I PSD Area. The UTM coordinates for this facility are Zone 17; 520.1 km E; 3137.6 km N.

FIGURE 1



2.2 Standard Industrial Classification Codes (SIC)

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

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2.3 Facility Category

This facility generates electric power from five 190-MW dual-fuel “F” class combustion turbines. The combustion turbines are serviced by General Electric.

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/PM₁₀), sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications at the facility resulting in emissions increases greater than the following require review per the PSD rules as well as a determination for Best Available Control Technology (BACT) per Rule 62-212.410, F.A.C.: 40 TPY of NO_x, 40 TPY of SO₂, 25/15 TPY of PM/PM₁₀, 7 TPY of Sulfuric Acid Mist, 100 TPY of CO or 40 TPY of VOC.

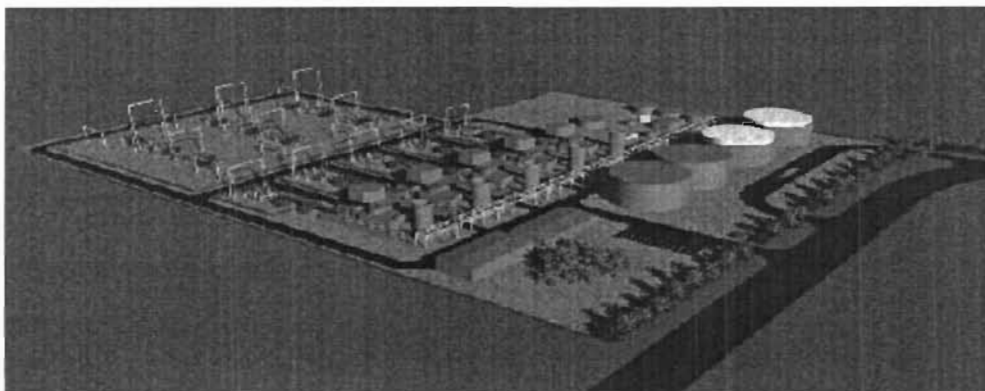
3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	190 Megawatt Combustion Turbine
002	Power Generation	190 Megawatt Combustion Turbine
003	Power Generation	190 Megawatt Combustion Turbine
004	Power Generation	190 Megawatt Combustion Turbine
005	Power Generation	190 Megawatt Combustion Turbine
006	Fuel Storage	2.8 Million Gallon Fuel Oil Storage Tank
007	Fuel Storage	2.8 Million Gallon Fuel Oil Storage Tank

Oleander Power Project, L.P. proposes to install a nominal 950-megawatt (MW) independent power production facility (5 new simple cycle combustion turbines, Units 1-5) for the Oleander Power Project located at 527 Townsend Road in Cocoa, Brevard County. The project includes five advanced Frame “7” class (or GE Frame 7FA) combustion turbines operating primarily on natural gas and a two fuel oil storage tanks. See Figure 2.

FIGURE 2



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The main fuel will be natural gas and the unit will operate up to 3390 hours per year, of which no more than 1000 hours represent fuel oil operation and approximately 730 represent "low load" operation (2 hours per day). The project will result in emissions of carbon monoxide (CO), sulfur dioxide (SO₂), sulfuric acid mist (H₂SO₄), particulate matter (PM/PM₁₀), volatile organic compounds (VOC) and nitrogen oxides (NO_x). PSD review is required for each of these pollutants, since emissions (per the application) will increase by more than their respective PSD significant emissions levels.

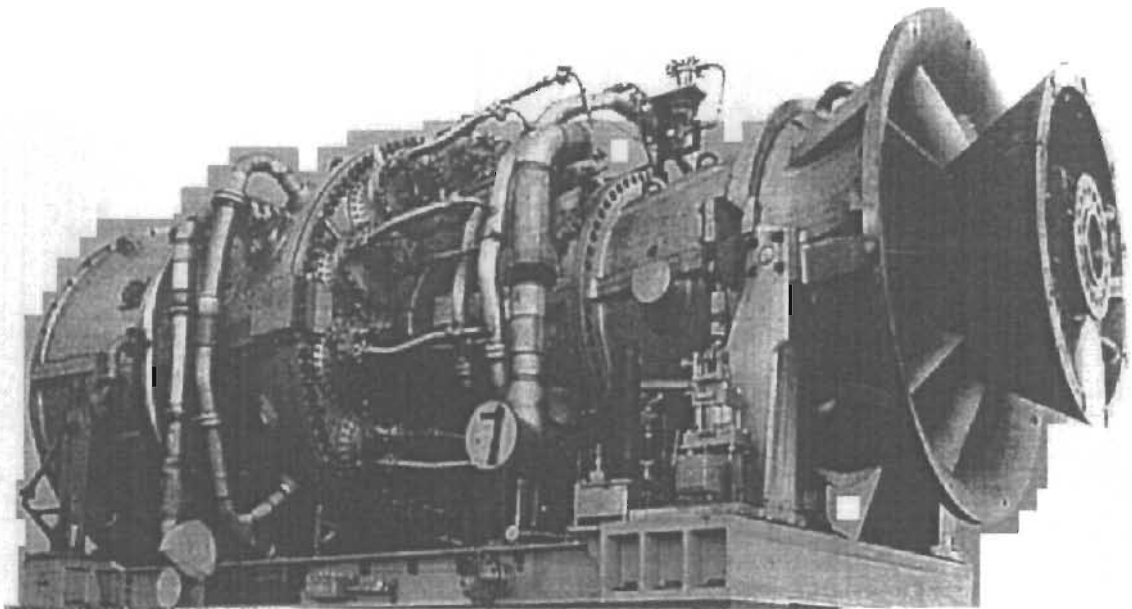
4. PROCESS DESCRIPTION

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.

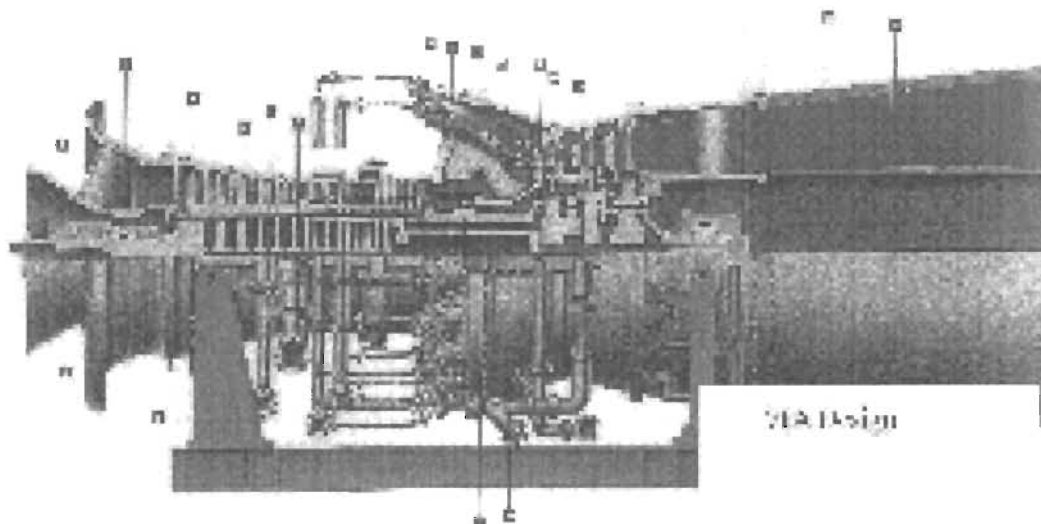
An exterior view of the GE MS 7001FA (a predecessor of the MS 7241FA) is shown in Figure 3. An internal view is shown in Figure 4.

FIGURE 3



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FIGURE 4



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.

In the Oleander 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. In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

Additional process information related to the combustor design, and control measures to minimize NO_x formation are given in the draft BACT determination.

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 is located in Brevard County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM₁₀, CO, SAM, SO₂, VOC and NO_x exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

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This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM₁₀, VOC, CO, 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 PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

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

5.2 Federal Rules

40 CFR 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)
40 CFR 52	Prevention of Significant Deterioration of Air Quality (applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed Units 1-5 will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, sulfuric acid mist, and negligible quantities of fluorides, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units 1-5 are summarized in the Draft BACT document and Specific Condition Nos.20-25 of Draft Permit PSD-FL-258.

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6.2 Emission Summary

Table 1 PSD Applicability Summary			
POLLUTANTS	POTENTIAL EMISSIONS (TPY)	PSD SIGNIFICANT EMISSION RATE (TPY)	PSD REVIEW REQUIRED
PM	96	25	Yes
PM ₁₀	96	15	Yes
SO ₂	291	40	Yes
NO _x	1235	40	Yes
CO	412	100	Yes
Ozone (VOC)	64	40	Yes
Sulfuric Acid Mist	44.4	7	Yes
Total Reduced Sulfur	NEG ^b	10	No
Hydrogen Sulfide	NEG ^b	10	No
Reduced Sulfur Compounds	NEG ^b	10	No
Total Fluorides	NEG ^b	3	No
Mercury	NEG ^b	0.1	No
Beryllium	NEG ^b	0.0004	No
Lead	NEG ^b	0.6	No
MWC Organics	< 8.8 x 10 ⁻⁸	3.5 x 10 ⁻⁶	No
MWC Metals	NEG ^b	15	No
MWC Acid Gases	11.3	40	No

a Based on emissions from operating at baseload conditions at 59 °F; firing natural gas and distillate fuel oil for 2,390 and 1,000 hours per year, respectively;

b NEG = negligible emissions

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, SO₂, CO, SAM, VOC and PM/PM₁₀. 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 six pollutants at levels in excess of PSD significant amounts: PM₁₀, CO, SO₂, NO_x, SAM and VOC. PM₁₀, SO₂, 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 and VOC are criteria pollutants and have only AAQS and significant impact levels defined for them. Since the project's VOC emissions increase is less than 100 tons per year no air quality analysis is required for VOC. SAM is a non-criteria pollutant and

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has no AAQS or PSD increments defined for it; therefore, no air quality impact analysis was required for SAM. PM is a criteria pollutant, but has no AAQS or PSD increments defined for it; therefore, no air quality impact analysis was required for it either. Instead, the BACT requirement will establish the PM and SAM emission limits for this project.

A review of the applicant's initial PM₁₀, CO, SO₂ and NO_x air quality impact analyses for this project revealed no predicted significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM₁₀, CO, SO₂ and NO_x;
- An analysis of impacts on soils, vegetation, and 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 Analysis of Existing Air Quality and Determination of Background Concentrations

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. The monitoring requirement may be satisfied by using existing representative monitoring data, if available. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimus concentration. In addition, if EPA has not established an acceptable monitoring method for the specific pollutant, monitoring may not be required.

If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling.

The table below shows that predicted SO₂, CO, PM₁₀ and NO_x impacts from the project are predicted to be below the appropriate de minimus levels; therefore, preconstruction ambient air quality monitoring is not required for these pollutants.

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Maximum Project Air Quality Impacts for Comparison to De Minimus Ambient Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m ³)	De Minimus Ambient Impact Level (ug/m ³)	Impact Above/Below De Minimus
SO ₂	24-hour	1.1	13	BELOW
PM ₁₀	24-hour	0.3	10	BELOW
CO	8-hour	2.4	575	BELOW
NO ₂	Annual	0.3	14	BELOW

6.4.3 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model 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 satisfy the good engineering practice (GEP) stack height criteria.

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

For determining the project's significant impact area in the vicinity of the facility, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.4.4 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions. If this modeling shows significant impacts, further modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS and PSD increments. The receptor grid for predicting maximum concentrations in the vicinity of the project was a polar receptor grid comprised of 578 receptors. This grid included receptors located on 18 radials. Along each radial, 36 receptors were located at 10° intervals and distances of 0.1, 0.2, 0.3, 0.5, 0.7, 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 4.5, 5.0, 7.0, 10.0, 12.0 and 15.0 km from the proposed CT stack locations. The tables below show the results of this modeling.

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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)	Significant Impact Level (ug/m)	Significant Impact?
PM ₁₀	Annual	0.02	1	NO
	24-hour	0.32	5	NO
CO	8-hour	2	500	NO
	1-hour	19	2000	NO
NO ₂	Annual	0.31	1	NO
SO ₂	Annual	0.08	1	NO
	24-hour	1.1	5	NO
	3-hour	7.9	25	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.5 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, Visibility, And Wildlife

The maximum ground-level concentrations predicted to occur for PM₁₀, CO, NO_x, SO₂, and VOC as a result of the proposed project, including background concentrations and all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the PSD Class II area.

Impact On Visibility

Natural gas and No. 2 fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NO_x and SO₂ emissions will also minimize plume opacity. Because no add-on control equipment (with associated reagents) is required, there will be no tendency to form ammoniated particulate species.

Growth-Related Air Quality Impacts

The proposed project is being constructed to meet an electric demand opportunity. Additional growth as a direct result of the additional electric power provided by the project is not expected. The project will be constructed and operated with minimum labor and associated facilities and is not expected to significantly affect growth in the area. Although this project was not reviewed by the Public Service Commission, recent determinations indicate a growing demand for generation to meet shrinking electrical reserves. Although there are no adequate procedures under PSD to fully assess these impacts, the type of project proposed has a very small footprint for a 950 megawatt plant.

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7. PUBLIC INPUT

Opportunities to request a public meeting are usually provided in the Notice of the Department's Intent published in a local newspaper. At the request of various members of the community, a public meeting was held on March 3, 1999 at the Brevard County Agricultural Center in Cocoa, Florida. Since receipt of the application, staff reviewing the application public have addressed a number of inquiries from the public and local officials regarding the project, its impacts, emissions from nearby facilities, the review process, etc.

There has been particular interest in the reasons why the project is not subject to review by the Public Service Commission and the Siting Board. It was explained (as understood by the Department) that one reason is that the power is not generated from steam and those needing further requesting information were directed to follow up with the Public Service Commission and provided statutory references, locations, website addresses, and phone numbers.

At the request of the attendees at the first meeting, the Department will conduct another meeting on May 13, 1999 from 7:00 to 9:00 p.m., at the same location as the first meeting. The Department will prepare a more detailed response to the questions raised during both meetings when it issues its final action on the application. At this time, there are at least two issues that were taken into consideration and addressed in this action.

The issue of fuel oil usage was raised very early in the interaction with the public. Several members considered the planned fuel oil use as excessive for gas-fired unit with fuel oil back up. In response to the concerns raised by the Department and the public, Oleander revised its requested fuel oil use limit from 2,000 to 1,000 hours per year. At the public meeting, a specific request was made that Oleander further limit the fuel oil usage from a range of 1/3 of the operating time to 100 hours per year. The Department has reviewed this as follows:

- Oleander's request is not inconsistent with other permitting actions, which have occurred in the state. For example, the GRU Deerhaven (FL) unit CT3 which is a 74MW Simple Cycle unit with permitted NO_x emissions of 15ppm (gas) and 42ppm (oil) has been permitted to operate on oil for 2000 hrs/year out of 3900 hours total operating time. Technically, this unit is permitted to operate for 2000 hours per year on oil, whether or not it burns any gas. A newly proposed plant (TECO Polk County, FL) is a 330 MW (2x165) Simple Cycle unit with proposed emissions of 10.5 ppm (gas) and 42 ppm (oil). The CT's are requested to operate for 876 hours oil/CT out of 4380 hours total. Again, no limitation exists that precludes the plant from only burning oil.
- Since the Oleander application specified that fuel oil was intended to be for back-up purposes, a specific permit condition is being proposed to limit the fuel oil usage to be less than the gas usage (on a BTU basis). This is more stringent than other similar permitting actions.

The issue of ozone monitoring was raised, with a specific request to include ozone monitoring for a year in the area of the proposed plant. Following is the Department's review:

- Cases where the projected impact of a source is less than the "significant monitoring concentration" are generally exempt from preconstruction monitoring data (via the "de Minimus" concept). For ozone, the "de Minimus" threshold for monitoring has been established at 100 tons/year of VOC. The maximum potential to emit VOC from this facility has been determined to be 64 tons per year. Hence, preconstruction ozone monitoring (to determine, for example, if the project can be constructed) is not required.

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- If preconstruction monitoring were to be required, the monitor location would almost certainly not be near the location of the plant. The ozone-monitoring network in Florida is designed based on the federal requirements for ambient monitoring networks. The network size is based largely on the number of urban areas, which have a population of greater than 200,000 people. Cocoa Beach-Palm Bay is one such area and is one of only fourteen counties in the state which has two ozone monitors.
- One of these monitors is required to be sited to monitor the maximum concentration that is expected in that area. Due to the meteorology experienced and peninsular design of Florida, the sea breeze impact creates conditions for the highest expected ozone levels; the areas where ozone has been found to be worst is on or near the coast. To form, ozone generally requires volatile organic compounds and nitrogen oxides to mix in the presence of sunlight. Even so, ozone is a very reactive molecule.
- In any event, it would be very difficult to attribute changes in ozone concentrations, before and after construction, to the operation of the plant. The local ozone impacts of the plant would be masked by changes in emissions at the other electrical power plants, cyclical meteorological phenomena, growth in vehicular traffic, etc.
- Nevertheless, the Department requests that Oleander consider, as a good corporate citizen, the installation and operation of a station in the neighborhood to provide the citizens with requested information about air quality in the area.

8. 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, provided the Department's BACT determination is implemented.

Michael P. Halpin, P.E. Review Engineer
Cleveland Holladay, Meteorologist
A. A. Linero, P.E., Administrator

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Oleander Power Project
Oleander Power Project, L.P.
PSD-FL-258 and 0090180-001-AC
Brevard County, Florida

BACKGROUND

The applicant, Oleander Power Project, L.P., proposes to install a nominal 950 megawatt (MW) independent power production facility (5 new simple cycle combustion turbines) at 527 Townsend Road, Cocoa, Brevard County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM₁₀), carbon monoxide (CO), volatile organic compounds (VOC), sulfur dioxide (SO₂) and nitrogen oxides (NO_x). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The five units to be installed are 190-MW dual-fuel "F" class combustion turbines. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated March 26, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on November 24, 1998 and included a proposed BACT prepared by the applicant's consultant, Golder Associates Inc. The application was revised on February 1, 1999 incorporating responses to completeness questions by FDEP and revised again on March 17, 1999 proposing lower emissions levels based upon vendor data and guarantees.

REVIEW GROUP MEMBERS:

Michael P. Halpin, P.E. and A. A. Linero, P.E.

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil Use (1000 hr/yr.) Combustion Controls	9 lb/hr (Gas) 17 lb/hr, 0.05% sulfur (Oil)
Volatile Organic Compounds	As Above	3 ppm (Gas) 6 ppm (Oil)
Visibility	As Above	10 percent
Carbon Monoxide	As Above	12 ppm (Gas, baseload) 20 ppm (Oil, baseload)
Sulfuric Acid Mist	As Above	1 gr. S/100 scf of natural gas 0.05% sulfur oil
Nitrogen Oxides	Dry Low NO _x Burners (Gas) Water Injection (Oil)	9 ppm @ 15% O ₂ (Gas, baseload) 42 ppm @ 15% O ₂ (Oil, baseload)

According to the application, the maximum emissions from the facility will be approximately 1235 tons per year (TPY) of NO_x, 412 TPY of CO, 96 TPY of PM/PM₁₀, 291 TPY of SO₂ and 64 TPY of VOC.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

BACT DETERMINATION PROCEDURE:

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

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

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

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, and 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 ppm NO_x @ 15% O₂. (assuming 25 percent efficiency) and 150 ppm SO₂ @ 15% O₂. (or <0.8% sulfur in fuel). The BACT proposed by the applicant is more stringent than the NSPS. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY EPA AND STATES:

Most recent stationary gas turbine BACT determinations made to-date by EPA and the states, including the State of Florida, have been much more stringent than the requirements of the NSPS. The following table is a sample of information on recent BACT and a few Lowest Achievable Emission Rate (LAER) determinations made by EPA and the States for stationary gas turbine projects as large or larger than the one under review. LAER is required in areas where the ambient air (unlike that Florida) does not attain the National Ambient Air Quality Standards (NAAQS).

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Project Location	Power Output and Duty	NO _x Limit Ppm @ 15% O ₂ and Fuel	Technology	Comments	F.O. LIMIT	Year Permit Issued
FPC DeBary FL	311 MW SC	N/A	None	6x51.9MW GE MS7000 CT	N/A	1974
	372 MW SC	25 – NG 42 – FO	WI	4x92.9MW GE PG7111EA CT	Total hrs/CT 3390 hrs/yr. gas or oil	1991
FPC Intercession City FL	385 MW SC	25 – NG 42 – FO	DLN WI	4x96.3MW GE PG7111EA CT	Total hrs/CT 3390 hrs/yr. gas or oil	1991
	171 MW SC	25 – NG 42 – FO	DLN WI	171 MW Siemens V84.3 CT	Total hrs/CT 3390 hrs/yr. gas or oil	1995
Kamine/Besicorp NY	79 MW CC	9 – NG 55 – FO	DLN	79 MW Siemens V64.2	2000 hrs/yr.	1992
Hart County, GA	318 MW SC	25 – NG 42 – FO	DLN & WI	2x159 MW GE7FA CT's	Total hrs/CT 2500 hrs/yr. gas or oil	1992
FPC Tiger Bay, FL	270 MW CC	15/10-NG 42 – FO	DLN &/or SCR WI	184 MW GE MS7001FA CT DLN/15 or SCR/10 ppm	3.7M gal/yr.	1993
Auburndale Power FL	156 MW CC	25/15 - NG 42 – FO	DLN & WI	1x156 MW WH 501D5 CT	400 hrs/yr.	1993
FPC Hines Polk, FL	485 MW CC	12 – NG * 42 – FO	DLN & SCR WI	2x165 MW WH 501FC CTs	1000 hrs/yr. out of 8760	1994
GRU Deerhaven FL	74 MW SC	15 – NG 42 – FO	DLN WI	CT #3; 74 MW	2000 hrs/yr. out of 3900	1995
PREPA, PR	248 MW SC	10 - FO	WI & Hot SCR	3x83 MW ABB GT11N CTs	2000 hrs/yr. < 60% output	1996
City Tallahassee, FL	260 MW CC	12 – NG 42 – FO	DLN WI	160 MW GE MS 7231FA CT DLN Guarantee is 9 ppm	NO _x site cap of 467 TPY	1997
Berkshire, MA	272 MW CC	3.5 – NG (LAER) 9.0 – FO	DLN & SCR WI & SCR	178 MW ABB GT24 CT	No oil from 5/1 thru 9/30; 3 hr <50% su/sd	1997
Lordsburg, L.P. NM	100 MW SC	15/25 – NG 42/60 - FO	DLN WI	100 MW WH 501D5A or equiv. (NO _x values are >/< 75% output)	1440 hrs/yr.	1997
City of Lakeland, FL	250 MW SC	9 – NG 42 – FO	ULN on gas, WI on oil 4/30/2002.	230 MW WH 501G CT	250 hrs/CT per year	1998
		9 – NG 15 – FO	Hot SCR if 9ppm not achievable by ULN 4/30/2002		250 hrs/CT per year	
TECO Polk, FL	330 MW SC	10.5 - NG 42 - FO	DLN WI	2x160 MW GE MS 7241FA CT's	876 hr/CT out of 4380	1999 proposed
RockGen, Wis.	525 MW SC	15 – NG 42 – FO	DLN WI	3x175 MW CT's	800 hr/CT out of 3800; not operated <50% continuously	1999

SC = Simple Cycle ULN = UltraDry Low NO_x DLN = Dry Low NO_x Combustion GE = General Electric
 CC = Combined Cycle MW = Megawatt SCR = Selective Catalytic Reduction WH = Westinghouse
 NG = Natural Gas FO = Fuel Oil WI = Water or Steam Injection ABB = Asea Brown Bovari
 CT = Combustion Turbine ISO = 59°F * = Equivalent Basis ppm = parts per million

All determinations are BACT unless denoted as LAER. Factors in common with project are denoted with **bold** type. Data derived from appropriate BACT determination or permit conditions.

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Project Location	CO – ppm (or lb/MMBtu)	VOC - ppm (or lb/MMBtu)	PM - lb/MMBtu (or gr./dscf or lb/hr)	Technology and Comments
FPC DeBary FL	None	None	None	Clean Fuels Good Combustion
	54 lb/hr	5 lb/hr	15 lb/hr	Clean Fuels Good Combustion
Intercession City FL	21.3 lb/hr - NG 25 - FO (25 ppm)	3 lb/hr - NG 5 lb/hr - FO	7.5 lb/hr - NG 15 lb/hr - FO	Clean Fuels Good Combustion
	30.9 lb/hr - NG 79 - FO (25 ppm)	5.3 lb/hr - NG 9 lb/hr - FO	7.5 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Kamine/Besicorp NY	9.5 – NG 9.5 – FO	0.007 lb/MMBtu	0.008 - NG 0.03 - FO	Clean Fuels Good Combustion
Hart County, GA	25 – NG 25 – FO	None	0.0064 - NG 0.0156 - FO	Clean Fuels Good Combustion
Tiger Bay, FL	15 – NG 30 – FO	2.8 lb/hr - NG 7.5 lb/hr - FO	0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Auburndale Power FL	21/15 – NG 25 – FO	6 lb/hr – NG 10 lb/hr - FO	0.0134 – NG 0.0472 - FO	Clean Fuels Good Combustion
Hines Polk, FL	25 – NG 30 – FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
GRU Deerhaven FL	None	None	None	Clean Fuels Good Combustion
PREPA, PR	9 – FO	11 - FO	0.0171 gr./dscf	Clean Fuels Good Combustion
Tallahassee, FL	25 – NG 90 – FO	None	9 lb/hr - NG 17 lb/hr - FO	Clean Fuels Good Combustion
Berkshire, MA	4 - NG (LAER) 5 - FO (LAER)	4 - NG 16 - FO	0.0105 - NG 0.0468 - FO	Clean Fuels CO Catalyst
Lordsburg, L.P. NM	10/200 - NG (>/< 75%) 90/150 - FO (>/< 75%)	6/11 - NG 8/11 - FO	5.3 lb/hr - NG 40.6 lb/hr - FO	Clean Fuels CO Catalyst
Lakeland, FL	25 - NG or 10 by Ox Cat 90 – FO	4 - NG 10 - FO	0.01 gr./dscf	Clean Fuels Good Combustion
TECO Polk, FL	15 – NG 33 – FO	7 - NG 7 - FO	10 lb/hr - NG 27 lb/hr – FO	Clean Fuels Good Combustion
RockGen, Wis.	12 - NG 15 - FO	2 - NG 5 - FO	18 lb/hr – NG 44 lb/hr - FO	Clean Fuels Good Combustion

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Comments from the U.S. Fish and Wildlife Service, Air Quality Branch dated December 18, 1998 and February 10, 1999.
- DOE website information on Advanced Turbine Systems Project
- Mitsubishi website
- Oleander Power Website: <http://www.oleanderpower.com/>
- Alternative Control Techniques Document - NO_x Emissions from Stationary Gas Turbines
- Goal Line Environmental Technologies' Website: <http://www.glet.com>
- Catalytica Combustion System's Website: <http://www.catalytica-inc.com/cs/>

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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.

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 Oleander 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 equivalent 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 (ppm @15% O₂). The Department estimates uncontrolled emissions at approximately 200 ppm @15% O₂ for each turbine of the Oleander 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 about 42 ppm when firing fuel oil in large combustion turbines. These values may form the basis 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 increase emissions of both of these pollutants.

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 depicted

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

To further reduce NO_x emissions, GE developed the DLN-2 combustor (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and the combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

Further improvements in the DLN design were made by GE. The most recent version is the DLN-2.6 (proposed for Oleander). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppm NO_x limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

NO_x concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_x at concentrations of 15 parts per million (ppm) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppm 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.

The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_x and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the Oleander project are shown in Figure 4.

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, results in a lower achievable thermal efficiency.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

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

The relationship between flame temperature, firing temperature, unit efficiency, and NO_x formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppm (and even lower) from gas turbines smaller than about 200 MW (simple cycle), such as the F class.

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 and excess oxygen yielding molecular nitrogen and water. The catalyst used in combined cycle, low temperature applications (conventional SCR), is usually vanadium or titanium oxide and accounts 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. Per the above table, only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR (it is currently being started up). The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppm by DLN technology at the time the units were to start up in 1998. SCR is also proposed on a permanent basis for the expansion of the FPC Hines Facility (Power Block II). The Department was recently advised by Seminole Electric that SCR will be installed on the 501F unit at the Hardee Unit 3 project. Permit BACT limits as low as 3.5 ppm NO_x have been specified using SCR for several combined cycle F Class projects in Alabama and Mississippi. By comparison, a 6 ppm value at baseload facility proposed by FPC (Hines Energy Complex Power Block 2) is typical and is the lowest limit proposed to-date in Florida. According to that application, the 6 ppm value will be maintained at 80 percent load. FPC has estimated concentrations of 10 ppm at 50 percent load while firing gas.

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Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that ammonia injection occurs closer to the turbine in 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 simple cycle 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 Santa Rosa Energy Center, which incorporates a large 600 MMBtu/hr duct burner in the HRSG and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

Emerging Technologies

•SCONOx - USEPA has identified an “achieved in practice” BACT value of 2.0 ppmv over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx system. Additional advantages of the SCONOx process include the elimination of ammonia and the control of some CO emissions. In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx process was deemed as technically feasible for maintaining NO_x emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx for United States turbine applications > 100 MW, and ABB Power Generation has stated that scale up and engineering work will be required before SCONOx can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project.

•XONON™ - Catalytica Combustion Systems, Inc. develops manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides (NO_x), a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON™ system is purported to be a powerful technology that essentially eliminates the formation of NO_x in gas turbines without impacting the turbine's operating performance. On November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to

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be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

REVIEW OF PARTICULATE MATTER (PM/PM₁₀) 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 (PM₁₀). Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for no more than 1000 hours per year making any conceivable add-on control technique for PM/PM₁₀ either unnecessary or impractical.

A technology review indicated that the top control option for PM₁₀ is a combination of good combustion practices, fuel quality, and filtration of inlet air. The applicant indicated that the PM₁₀ emissions will not exceed 0.01 gr./scf when firing natural gas and pointed out that such a value is equal to a typical specification for baghouse design. Annual emissions of PM₁₀ are expected to be approximately 20 tons per C.T. for the maximum case of 1000 hours of fuel oil and 2390 hours of natural gas firing.

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.

Most installations using catalytic oxidation are located in the Northeast. Among them are the 272 MW Berkshire, Massachusetts facility, 240 MW Brooklyn Navyyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric 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.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 at full load, even as they achieve relatively low NO_x emissions by SCR or dry low NO_x means. By comparison, the projected actual values of 12 and 20 ppm for gas and oil respectively (at baseload) as proposed in Oleander's application appear typical or low. These values are given in the application as representative down to and including 50 percent load on each fuel respectively

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 as the combustion turbine itself

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is very efficient at destroying VOC. The limits proposed for this project are 3 and 6 ppm for gas and oil firing respectively.

REVIEW OF SULFUR DIOXIDE (SO₂) AND SULFURIC ACID MIST (SAM)

SO₂ 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 SO₂. For this project, the applicant has proposed as BACT the use of such fuels with 0.05% sulfur oil and natural gas containing no more than 1 grain of sulfur per standard cubic foot (gr. S/f³). This value is well below the “default” maximum value of 20 gr. S/f³, but high enough to require a BACT determination. Emissions were estimated by the applicant to be 291 TPY of SO₂ and 45 TPY of SAM. However the Department expects the emissions to be lower because oil consumption will be further reduced and typical natural gas in Florida contains less than 1 gr. S/f³.

BACKGROUND ON PROPOSED GAS TURBINE

In the original application, the applicant had not yet selected the supplier for the proposed five “F” class CT’s and (via GolderAssociates) conducted its own BACT review assuming either a General Electric 7FA or a Westinghouse 501F. In a February 1, 1999 response to FDEP’s completeness questions, the applicant stated that “Oleander Power Project, L.P. has selected General Electric Company (GE) as its primary vendor to supply the turbines for the project due to the ability of GE combustion turbines to meet a NO_x emission level of 9 ppmvd (corrected to 15 percent O₂). The applicant requests the ability to purchase a different manufacturer’s machines, if they can meet the same emission characteristics as the GE machine and the emission limits approved by FDEP in the final permit. As indicated in the application, the machines will be the advanced Frame “7” class (or GE Frame 7 FA), which would be capable of achieving an NO_x emission rate of 9ppmvd @ 15% O₂ when firing natural gas.”

In the submittal dated March 17, 1999 the applicant further affirmed its intentions to procure GE combustion turbines stating “... the updated forms and information reflect data representative of the General Electric (GE) Frame 7FA combustion turbine as the primary vendor...” as well as “Over the last several months, the applicant has recognized the concern by the Department and the general public over the higher emission rates when firing distillate fuel oil relative to natural gas. Both the reduction in hours of firing oil and the lower emission rates with the GE machine substantially reduce emissions, a desired goal.”

Westinghouse and General Electric are counting on further advancement and refinement of DLN technology to provide sufficient NO_x control for their turbines. In the case of the WH501 G, steam cooling of the transition piece allows the unit to maintain the same NO_x formation potential as the WH501 F while achieving a higher turbine inlet (firing) temperature. Examples of Westinghouse combustors are shown in Figure 6. These include their second generation of Dry Low NO_x combustors including their fully pre-mixed Piloted Ring Combustor. Where required by BACT or LAER determinations of certain states, both companies incorporate SCR in combined cycle projects.

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The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7 FA units (160 MW gas turbines with firing temperatures of 2400 °F) reportedly met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA.

Westinghouse and General Electric are partners with the Department of Energy (DOE) in the Advanced Turbine Systems (ATS) Program. The Mission/Vision Statement of ATS is to "develop base-load advanced turbine systems for commercial offering in the year 2000." Among the goals of the Program is 60 percent combined cycle efficiency while achieving NO_x emissions of 8 ppm or less. The cost of producing the prototypes is estimated at \$435,000,000 and \$300,000,000 for the GE and Westinghouse projects respectively.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Oleander project assuming full load. Values for NO_x are corrected to 15% O₂. These limits or their equivalents in terms of pounds per hour, as well as the applicable averaging times are given in the permit Specific Conditions. The rationale for the averaging times is discussed in the Final Determination addressing comments by the applicant and EPA and which is being issued concurrently with this determination.

Operational Mode (Fuel)	NO _x (15%O ₂)	CO	VOC	PM/Visibility (% Opacity)	SO ₂ /SAM	Technology and Comments
Natural Gas	9 ppm	12 ppm	3 ppm	10	1 grain S per 100 CF	Dry Low NOx Burners. Clean fuels, good combustion
Fuel Oil	42 ppm	20 ppm	6 ppm	10	0.05% sulfur oil	Water Injection. Units limited to 1000 hrs equivalent full load oil operation (per CT) annually. Clean fuels, good combustion

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The initial 9 and 42 ppm NO_x limits proposed by Oleander are guaranteed by General Electric.
- The units will be operated in simple cycle mode and therefore certain control options, which are feasible for combined cycle units, are not applicable. This rules out low temperature technologies such as SCONOx and conventional SCR, which can achieve lower limits.
- The 9 ppm limit while firing natural gas is the lowest known BACT value for an "F" frame combustion turbine operating in simple cycle mode and peaking duty. The initial 42 ppm limit while firing fuel oil is typical.
- There is a cost to Oleander for the 9 ppm guarantee compared to the 15 ppm guarantee provided by GE for an identical unit to be installed at Jacksonville Electric Authority's Kennedy Plant. There may be additional costs for the more frequent tuning needed to maintain the units at less than 9 ppm.

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- Typical permit limits nation-wide for these units while operating in simple cycle mode and intermittent duty are 12-15 ppm. The lower limit will offset emissions while firing fuel oil.
- The simple cycle turbine has very high exhaust temperatures of up to 1200 °F, which is at the higher operating limit of Hot SCR zeolite catalyst (around 1050 °F). The PREPA continuous duty simple cycle turbines (referenced above) have exhaust temperatures ranging from 824 to 1024 °F and the Hot SCR catalyst (which must achieve 10 ppm NO_x) is located between the turbine and a “Once Through Steam Generator”.
- The levelized costs of NO_x removal by Hot SCR were estimated by Golder Associates as \$11,000 per ton of NO_x removed at 2000 hrs/yr. of oil operation, \$14,000 per ton of NO_x removed at 1500 hrs/yr. of oil operation and \$17,568 per ton removed at 1000 hrs/yr. of oil operation. Although the estimates appear to be high for this project (e.g.: 3 days of lost energy costs for peaking units operating at no more than 39% capacity factor; no indication of a continuation of the actual downward trend in catalyst prices, progressively improving performance, and typically longer-than-expected life), the actual per ton cost reasonably exceeds \$10,000 at 1000 hrs/yr. of oil operation.
- Using much of the basic capital cost information developed by the City of Lakeland, The National Park Service estimated the cost of NO_x removal by Hot SCR at \$3,802 per ton (excluding the energy penalty) for a *continuous duty* 501 G. A further refinement of the Park Service estimate by including the energy penalty, using the revised catalyst cost data obtained by the Department, and assuming a five year estimated life for the catalyst (per Engelhard) would yield a cost-effectiveness closer to \$3,500 per ton of NO_x removed for that application. Hence, should the Oleander Project contemplate operation on a more continuous duty, the use of a Hot SCR may be appropriate.
- Comments from the National Park Service on the Oleander project suggested a reduction in the proposed NO_x emissions on oil from 42ppm to 25ppm (at the applicant’s proposed 2000 hours of oil operation rate). Restricting the operation of these units to 1000 hours per year on oil at 42ppm will result in lower annual NO_x emissions than 2000 hours per year on oil at 25ppm.
- It is possible that the NO_x emissions while firing oil from may be reduced from 42ppm 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.
- Hot SCR has environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. Given the vendor guarantee of 9 ppm on natural gas, the limitation of total operating hours to 3390 per CT and the requirement that a majority of the operation be on natural gas, Hot SCR is not considered BACT for these simple cycle peaking units.
- It is possible and even likely, that Hot SCR catalysts will be improved and can be used to replace the initial catalyst as it degrades. Should the Oleander Project contemplate operation on a more continuous duty, or should actual emissions not achieve permitted levels such that energy, environmental and economic impacts (or other costs) may be reduced, the use of a Hot

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SCR may be BACT. The Department has concluded that Hot SCR is both technically and economically feasible for certain applications (e.g. Lakeland, FL which is shown above).

- BACT for PM₁₀ was determined to be good combustion practices consisting of: inlet air filtering; use of clean, low ash, low sulfur fuels; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM₁₀ emissions will be very low and difficult to measure at the high temperature exiting the stack in simple cycle operation. Additionally, the higher emission mode will involve fuel oil firing, which will occur no more than 1000 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. 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 FPL Fort Myers (Florida), Santa Rosa (Florida) and the City of Tallahassee (Florida) as well as the Berkshire (Massachusetts) projects in the above table.
- Annual CO emission estimates from the Oleander project are higher than for other pollutants except NO_x. However the impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_x, SO₂, or PM₁₀.
- Golder Associates evaluated the use of an oxidation catalyst designed for 75 percent reduction and having a three-year catalyst life. The oxidation catalyst control system was estimated to increase the capital cost of each unit by \$1,829,777 with an annualized cost of \$707,655 per year. Levelized costs for CO catalyst control were calculated at \$11,437 per ton to control CO emission to 75% removal. Catalytic CO control is not cost-effective for the Oleander project.
- The applicant's proposed CO levels of 12 ppmvd while firing natural gas and 20 ppmvd while firing oil are on the lower end of other permitted units neglecting those units which employ oxidation catalysts. These values are assumed to be guaranteed down to 50% of unit output.
- CO limits achievable by good combustion will be set equal to or lower than those set for other recent projects. For example, the City of Tallahassee project (25 ppm on gas and 90 ppm on oil), the FPC Hines project (25 ppm on natural gas and 30 ppm on oil) and the Tiger Bay project (limited to 15 ppm on natural gas and 30 ppm on oil). The two latter projects are both permitted at 8760 hours per year on natural gas and up to 1000 hours per year on oil (Hines).
- VOC emission limits proposed by the applicant are at the lower end of values previously determined as BACT. Good Combustion is sufficient to achieve these low levels.
- The (BACT) levels above are guaranteed down to 50% output. It is presumed that emission levels for pollutants such as NO_x and CO will increase above these guaranteed ppm levels at lower outputs. Therefore, startup and shutdown hours are defined to be hours of operation below 50% output and these hours will be limited by specific condition.
- 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 SO₂ and Sulfuric Acid Mist. Pipeline natural gas and very low (0.05%) sulfur oil are considered to be BACT for this project.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

COMPLIANCE PROCEDURES

Pollutant	Compliance Procedure
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO _x (24/3-hr average)	NO _x CEMS, O ₂ or CO ₂ diluent monitor, and flow device as needed
NO _x (performance)	Annual Method 20 (can use RATA if at capacity)
Sulfur Dioxide	Custom Fuel Monitoring Schedule

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:

Approved By:

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

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

Date:

PERMITTEE:

Oleander Power Project, L.P.
Oleander Power Project
250 West Pratt Street, 23rd Floor
Baltimore, MD 21201

File No.	0090180-001-AC
FID No.	0090180-001
SIC No.	4911
Permit No.	PSD-FL-258
Expires:	March 26, 2003

Authorized Representative:
Richard L. Wolfinger
Vice President

PROJECT AND LOCATION:

Permit for the construction of five 190-MW dual-fuel "F" class combustion turbines and two 2.8 million-gallon fuel oil storage tanks for back-up distillate fuel oil. The turbines are designated as Unit Nos. 1-5 and will be located at the Oleander Power Project, 527 Townsend Road, Cocoa, Brevard County. UTM coordinates are: Zone 17; 520.1 km E; 3137.6 km N.

STATEMENT OF BASIS:

This 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 permit is for the installation of five 190 MW simple cycle “F” class, gas and oil-fired, stationary combustion turbines, each with its own 60-foot stack and two 2.8 million gallon storage tank for back-up (0.05 percent sulfur) distillate fuel oil.

Emissions from the Oleander units will be controlled by Dry Low NO_x combustors while firing natural gas, wet injection when firing fuel oil, use of inherently clean fuels, and good combustion practices.

EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	190 Megawatt Combustion Turbine
002	Power Generation	190 Megawatt Combustion Turbine
003	Power Generation	190 Megawatt Combustion Turbine
004	Power Generation	190 Megawatt Combustion Turbine
005	Power Generation	190 Megawatt Combustion Turbine
006	Fuel Storage	2.8 Million Gallon Fuel Oil Storage Tank
007	Fuel Storage	2.8 Million Gallon Fuel Oil Storage Tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM₁₀), sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications at the facility resulting in emissions increases greater than the following require review per the PSD rules as well as a determination for Best Available Control Technology (BACT) per Rule 62-212.410, F.A.C.: 40 TPY of NO_x, 40 TPY of SO₂, 25/15 TPY of PM/PM₁₀, 7 TPY of SAM, 100 TPY of CO or 40 TPY of VOC.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 04/xx/99 Notice of Intent published in The XXXXX
- 03/26/99 Distributed Intent to Issue Permit
- 02/02/99 Application deemed complete
- 11/24/98 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 24, 1998
- Department letters dated November 25, December 17 and December 22, 1998
- Comments from the National Park Service dated December 18, 1998
- Letter from Oleander (via Golder Associates) dated February 1, 1999 including revisions to original application.
- Letter from Oleander (via Golder Associates) dated March 17, 1999 including further revisions to application.
- Department's Intent to Issue and Public Notice Package dated March 26, 1999
- 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 Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Central District office, 3319 Maguire Boulevard, Orlando, Florida 32803 and phone number 407/894-7555.
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. 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: In accordance with paragraph (4) of 40 CFR 52.21(j) 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."

SECTION II. ADMINISTRATIVE REQUIREMENTS

This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. [40 CFR 52.21(j)(4), Rule 62-4.070 F.A.C.]

8. 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 Central District office [Chapter 62-213, F.A.C.]
9. 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.]
10. 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 Central District office by March 1st of each year. [Rule 62-210.370(2), F.A.C.]
11. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
12. Permit 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.]
13. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's Central District office. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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.
2. 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.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
 - 40CFR60.7, Notification and Recordkeeping
 - 40CFR60.8, Performance Tests
 - 40CFR60.11, Compliance with Standards and Maintenance Requirements
 - 40CFR60.12, Circumvention
 - 40CFR60.13, Monitoring Requirements
 - 40CFR60.19, General Notification and Reporting requirements
4. ARMS Emission Units 001-005, Power Generation, consisting of five 190 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.]
5. ARMS Emission Units 006-007, Fuel Storage, consisting of two 2.8 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. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District office.

GENERAL OPERATION REQUIREMENTS

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

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to each Unit (1-5) at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,722 million Btu per hour (MMBtu/hr) when firing natural gas, nor 1,919 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 Central District office 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 stationary gas turbines shall only operate up to 3390 hours during any calendar year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
14. Fuel usage as heat input, while burning natural gas at the site, shall not exceed 29.188×10^{12} BTU (LHV) per year during any consecutive 12 month period. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]
15. Fuel usage as heat input, while burning fuel oil at the site, shall not exceed 9.595×10^{12} BTU (LHV) per year during any consecutive 12 month period. Additionally, the amount of fuel oil

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SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

burned at the site (in BTU's) shall not exceed natural gas burned at the site (in BTU's) during any consecutive 12-month period.

[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Control Technology

16. Dry Low NO_x (DLN) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_x) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]
17. The permittee shall design each stationary combustion turbine, ducting, and stack(s) so as to not preclude installation of SCR equipment and/or oxidation catalyst in the event of a failure to achieve the NO_x limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22. [Rule 62-4.070, F.A.C.]
18. 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.]
19. The DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_x emissions and CO emissions. 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

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_x are corrected to 15% O₂ on a dry basis. [Rule 62-212.400, F.A.C.]

Operational Mode (Fuel)	NO _x (15% O ₂)	CO	VOC	PM/Visibility (% Opacity)	SO ₂ /SAM	Technology and Comments
Natural Gas	9 ppm	12 ppm	3 ppm	10	1 grain S per 100 CF	Dry Low NO _x Burners. Clean fuels, good combustion
Fuel Oil	42 ppm	20 ppm	6 ppm	10	0.05% sulfur oil	Water Injection. Units limited to 1000 hrs equivalent full load oil operation (per CT) annually. Clean fuels, good combustion

21. Nitrogen Oxides (NO_x) Emissions:

- When NO_x monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- While firing Natural Gas: The emission rate of NO_x in the exhaust gas shall not exceed 62.6 lb/hr (at ISO conditions) on a 24 hr block average as measured by the continuous

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall not exceed 9 ppm @15% O₂ to be demonstrated by stack test. Note: Basis for lb/hr limit is 9 ppm @ 15% O₂, full load. [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% O₂ on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_x emissions calculated as NO₂ (at ISO conditions) shall not exceed 42 ppm @15% O₂ to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
 - Within 18 months after the initial compliance test, the permittee shall prepare and submit for the Department's review and acceptance an engineering report regarding the lowest NO_x emission rate that can consistently be achieved when firing distillate oil. This lowest recommended rate shall include a reasonable operating margin, taking into account long-term performance expectations and good operating and maintenance practices. The Department may revise the NO_x emission rate based upon this report. [BACT determination; Applicant request]
22. Carbon Monoxide (CO) emissions: The concentration of CO in the exhaust gas when firing natural gas shall not exceed 12 ppmvd when firing natural gas and 20 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 41.0 lb/hr (when firing natural gas) and 66.9 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]
23. Sulfur Dioxide (SO₂) emissions: SO₂ emissions (at ISO conditions) shall not exceed 5.5 pounds per hour when firing pipeline natural gas and 103.4 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. [Rule 62-212.400, F.A.C.]
24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil, except for during startup and shutdown at which time emissions shall not exceed 20 percent opacity. [Rule 62-296.320(4)(b), F.A.C.]
25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 3 ppmvd when firing natural gas and 6 ppmvd when firing fuel oil as assured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 5.9 lb/hr (when firing natural gas) and 11.5 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. 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. Operation below 50% output shall be limited to 2 hours per unit cycle (breaker closed to breaker open).

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SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

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.

27. Excess Emissions Report: If excess emissions occur due to malfunction, start-up or shut-down the owner or operator shall notify DEP's Central District office 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. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

28. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.
29. Initial (I) performance tests shall be performed on each unit while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after starting the CT) to air pollution control equipment, including low NO_x burners or Hot SCR. 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. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
- 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 compliance with 40CFR60 Subpart GG and (I, A) short-term NO_x BACT limits (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 requirement).
 - EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
30. 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 the applicable averaging

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

time of 24-hr block average (DLN technology) or a 3-hr average (if SCR is used). For the 24-hr block average (lb/hr) emissions may be determined via EPA Method 19 or equivalent EPA approved methods. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_x standard. These excess emissions periods shall be reported as required in Conditions 26 and 27. A valid hourly emission rate shall be calculated for each hour in which at least two NO_x concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

31. Compliance with the SO₂ and PM/PM₁₀ emission limits: Notwithstanding the requirements of Rule 62-297.310(7), F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO₂ and PM₁₀. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO₂ standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-941 or D4294-90 (or equivalent latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent latest version) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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) (1997 version).
32. Compliance with CO emission limit: 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 concurrent with the annual RATA testing for NO_x required pursuant to 40 CFR 75 (required for gas only).
33. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, CO emission limit will be employed as surrogate and no annual testing is required.
34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.

35. Test Notification: The DEP's Central District office 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). [40 CFR 60.11]
36. 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.
37. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.]

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by Oleander shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.
39. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed as per Condition 37. above. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.
40. Special Record Keeping Requirements: The owner or operator shall obtain, make, and keep the following records related to fuel usage:
 - (1) Monthly Fuel usage as heat input, for natural gas and fuel oil at the site.
 - (2) Fuel usage as heat input, for natural gas and fuel oil at the site for each consecutive 12-month period.
 - (3) Fuel usage as heat input, for natural gas and fuel oil at the site during each calendar year shall be submitted with the Annual Operation Report (AOR).
 - (4) Hours of operation for each combustion turbine shall be reported during each calendar year with the Annual Operation Report (AOR).

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each (CT) unit. Periods when NO_x emissions are above the standards as listed in Specific Condition No 21, shall be reported to the DEP Central District Office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the standards listed in Specific Condition No. 21 except as noted in Specific Condition No. 30. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]
42. 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 (1997 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_x CEMS. Upon request from DEP, the CEMS emission rates for NO_x shall be corrected to ISO conditions to demonstrate compliance with the NO_x standard established in 40 CFR 60.332.
43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Central District Office for review at least 90 days prior to installation.
44. 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 or superior grade fuel oil received at the Oleander Power Plant, 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).
45. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved (pending EPA concurrence) in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):
 - The permittee shall apply for an Acid Rain permit when the deadlines specified in 40 CFR 72.30.
 - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant of 40 CFR 75.11(d)(2)).

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

- Each unit shall be monitored for SO₂ emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USAEPA.
- Oleander shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

46. 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]