NEW SOURCE CONSTRUCTION PERMIT
Prevention of Significant Deterioration (PSD) Permit
Office of Air Quality
and
Vigo County Air Pollution Control

Mirant Sugar Creek LLC
6500 Darwin Road
West Terre Haute, IN 47885

(herein known as the Permittee) is hereby authorized to construct and operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this permit.

This permit is issued to the above mentioned company under the provisions of 326 IAC 2-1.1, 326 IAC 2-5.1, 326 IAC 2-6.1 and 40 CFR 52.780, with conditions listed on the attached pages.

This permit is also issued under the provisions of 326 IAC 2-2, 40 CFR 52.21, and 40 CFR 52.124 (Prevention of Significant Deterioration), with conditions listed on the attached pages.

Construction Permit No.: CP 167-12208-00123	
Original signed by Paul Dubenetzky Issued by: Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: May 9, 2001

TABLE OF CONTENTS

SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), and Vigo County Air Pollution Control (VCAPC). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-5.1-3(c)] [326 IAC 2-6.1-4(a)]

The Permittee owns and operates a natural gas merchant power plant.

Authorized Individual:	Kirk Covington
Source Address:	6500 Darwin Road, West Terre Haute, IN 47885
Mailing Address:	115 Perimeter Center West, Atlanta, GA 30338-4780
Phone Number:	(678) 579-3091
SIC Code:	4911
County Location:	Vigo
County Status:	Maintenance Attainment SO_2; Attainment for NO_X, CO, PM_{10}, Lead
Source Status:	Major, under PSD rules

A.2 Emissions units and Pollution Control Equipment Summary

This stationary source is approved to construct and operate the following emissions units and pollution control devices:

(a) Four (4) natural gas-fired combustion turbine generators, designated as units CT11, CT12, CT21, CT22, with a maximum heat input capacity of 1,490.5 MMBtu/hr (per unit on a lower heat heating value), and exhausts to stacks designated as E11B, E12B, E21B and E22B, respectively, for use when operating in simple cycle. During combined cycle operation exhaust goes to stacks designated E11A, E12A, E21A and E22A, respectively.

(b) Four (4) duct burners, designated as units DB11, DB12, DB21, DB22, with a maximum heat input capacity of 300 MMBtu/hr (per unit on a higher heating value basis) each and exhausts to stacks designated E11A, E12A, E21A, E22A, respectively.

(c) Four (4) heat recovery steam generators, designated as units HRSG11, HRSG12, HRSG21, HRSG22.

(d) Four (4) selective catalytic reduction systems, designated as units SCR11, SCR12, SCR21, SCR22.

(e) Two (2) natural gas fired auxiliary boilers, designated AB1 and AB2, with a maximum heat input capacity of 35 MMBtu/hr (per unit on a higher heating value basis), and exhausts to stacks E5 and E6 respectively.

(f) Two (2) steam turbines, designated as units ST1 and ST2.

(g) Two (2) cooling towers, designated as units COOL1 and COOL2, exhausts to stacks designated E3 and E4, respectively.

(h) Two (2) diesel fire pumps, each with a rating of 267 horsepower (hp).

(i) Two (2) diesel emergency generators, each with a rating of 1,475 horsepower (hp).

A.3 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

(c) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

A.4 Acid Rain Permit Applicability [326 IAC 2-7-2]

This stationary source shall be required to have a Phase II, Acid Rain permit by 40 CFR 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CFR 72.6.

(b) The source cannot operate the combustion units until their Phase II, Acid Rain permit has been issued.

SECTION B GENERAL CONSTRUCTION CONDITIONS

THIS SECTION OF THE PERMIT IS BEING ISSUED UNDER THE PROVISIONS OF 326 IAC 2-1.1 AND 40 CFR 52.780, WITH CONDITIONS LISTED BELOW.

B.1 Permit No Defense [IC 13]

This permit to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

B.2 Definitions

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, any applicable definitions found in IC 13-11, 326 IAC 1-2, and 326 IAC 2-1.1-1 shall prevail.

B.3 Effective Date of the Permit [40 CFR 124]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, this permit is effective immediately after the service of notice of the decision, except as provided in 40 CFR 124. Three (3) days shall be added if service of notice is by mail.

B.4 Revocation of Permits [326 IAC 2-2-8]

Pursuant to 326 IAC 2-2-8(a)(1) and 40 CFR 52.21, this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a period of eighteen (18) months or more.

B.5 First Time Operation Permit [326 IAC 2-6.1]

This document shall also become a first time operating permit pursuant to 326 IAC 2-5.1-3 when, prior to start of operation, the following requirements are met:

(a) Any modifications required by 326 IAC 2-1.1 and 326 IAC 2-7-10.5 as a result of a change in the design or operation of emissions units described by this permit have been obtained prior to obtaining an Operation Permit Validation Letter.

(b) The attached Affidavit of Construction shall be submitted to the Office of Air Quality (OAQ), Permit Administration & Development Section, and Vigo County Air Pollution Control (VCAPC).

(1) If the Affidavit of Construction verifies that the facilities covered in this Construction Permit were constructed as proposed in the application, then the facilities may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM and VCAPC.

(2) If the Affidavit of Construction does not verify that the facilities covered in this Construction Permit were constructed as proposed in the application, then the Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section prior to beginning operation of the facilities.

(c) If construction is completed in phases; i.e., the entire construction is not done continuously, a separate affidavit must be submitted for each phase of construction. Any permit conditions associated with operation start up dates such as stack testing for New Source Performance Standards (NSPS) shall be applicable to each individual phase.

(d) Upon receipt of the Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section, the Permittee shall attach it to this document.

(e) The operation permit will be subject to annual operating permit fees pursuant to 326 IAC 2-7-19 (Fees).

(f) Pursuant to 326 IAC 2-7-4(a)(1)(A)(ii) and 326 IAC 2-5.1-4, the Permittee shall apply for a Title V operating permit within twelve (12) months of the date on which the source first meets an applicability criterion of 326 IAC 2-7-2.

B.6 Phase Construction Time Frame

Pursuant to 326 IAC 2-1.1-9(5)(Revocation of Permits) and 40 CFR 52.21, IDEM and VCAPC shall revoke this permit to construct if the:

(a) Construction of Phase 1 has not begun within eighteen (18) months from the effective date of this permit or if during the construction of Phase 1, work is suspended for a continuous period of one (1) year or more.

(b) Construction of Phase 2 has not begun within eighteen (18) months after the operation of Phase 1 or if during the construction of Phase 2, work is suspended for a continuous period of one (1) year or more.

(c) Construction of Phase 3 has not begun within eighteen (18) months after the operation of Phase 2 or if during the construction of Phase 3, work is suspended for a continuous period of one (1) year or more.

The OAQ and VCPAC may extend such time upon satisfactory showing that an extension, formally requested by the Permittee is justified.

B.7 BACT Determination for Phase Constructions

Pursuant to 40 CFR 52.21(j)(4), for phase construction projects, the determination of BACT shall be reviewed and modified as appropriate at the latest reasonable time, which occurs no later than eighteen (18) months prior to the scheduled permitted commencement of construction of each independent phase of the project.

B.8 Local Agency Requirement

An application for an operation permit must be made ninety (90) days before start up to:

Vigo County Air Pollution Control
103 South Third Street
Terre Haute, IN 47807

The operation permit issued by Vigo County shall contain as a minimum the conditions in the Operation Conditions section of this permit.

B.9 NSPS Reporting Requirement

Pursuant to the New Source Performance Standards (NSPS), Part 60.7, Part 60.8, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

(c) Actual start-up date (within 15 days after such date); and

(d) Date of performance testing (at least 30 days prior to such date), when required by a condition elsewhere in this permit.

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue P.O. Box 6015
Indianapolis, IN 46206-6015

And

Vigo County Air Pollution Control
103 South Third Street
Terre Haute, IN 47807

The application and enforcement of these standards have been delegated to the IDEM, OAQ. The requirements of 40 CFR Part 60 are also federally enforceable.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

C.1 Major Source

Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration) and 40 CFR 52.21, and 326 IAC 2-7 (Part 70 Permit Program), this source is a major source.

C.2 Preventive Maintenance Plan [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMP) ninety (90) days after the commencement of normal operations after the first construction phase, including the following information on each emissions unit:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions;

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that failure to implement the Preventive Maintenance Plan does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMP's shall be submitted to IDEM, OAQ, and VCAPC upon request and shall be subject to review and approval by IDEM, OAQ, and VCAPC. IDEM, OAQ, and VCAPC may require the Permittee to revise its Preventive Maintenance Plan whenever lack of proper maintenance causes or contributes to any violation.

C.3 Source Modification [326 IAC 2-7-10.5]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-10.5 whenever the Permittee seeks to construct new emissions units, modify existing emissions units, or otherwise modify the source.

(b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control

103 South Third Street
Terre Haute, IN 47807

Any such application should be certified by the "responsible official" as defined by 326 IAC 2-7-1(34) only if a certification is required by the terms of the applicable rule.

C.4 Inspection and Entry [326 IAC 2-5.1-3(e)(4)(B)] [326 IAC 2-6.1-5(a)(4)]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, VCAPC, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a permitted source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under this title or the conditions of this permit or any operating permit revisions;

(c) Inspect, at reasonable times, any processes, emissions units (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit or any operating permit revisions;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) Utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

C.5 Transfer of Ownership or Operation [326 IAC 2-6.1-6(d)(3)]

Pursuant to [326 IAC 2-6.1-6(d)(3)]

(a) In the event that ownership of this source is changed, the Permittee shall notify IDEM, OAQ, Permits Branch, and VCAPC, within thirty (30) days of the change.

(b) The written notification shall be sufficient to transfer the permit to the new owner by an notice-only change pursuant to 326 IAC 2-6.1-6(d)(3).

(c) IDEM, OAQ, and VCAPC shall issue a revised permit.

The notification which shall be submitted by the Permittee does require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1.

C.6 Permit Revocation [326 IAC 2-1-9]

Pursuant to 326 IAC 2-1-9(a)(Revocation of Permits), this permit to construct and operate may be revoked for any of the following causes:

(a) Violation of any conditions of this permit.

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this permit.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this permit shall not require revocation of this permit.

(d) Noncompliance with orders issued pursuant to 326 IAC 1-5 (Episode Alert Levels) to reduce emissions during an air pollution episode.

(e) For any cause which establishes in the judgment of IDEM and VCAPC, the fact that continuance of this permit is not consistent with purposes of this article.

C.7 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes, sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity) monitor in a six (6) hour period.

C.8 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.9 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using good engineering practices (GEP) pursuant to 326 IAC 1-7-3.

Testing Requirements

C.10 Performance Testing [326 IAC 3-6]

(a) Compliance testing on new emissions units shall be conducted within 60 days after achieving maximum production rate, but no later than180 days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management

Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South Third Street
Terre Haute, IN 47807

no later than thirty-five (35) days prior to the intended test date. The Permittee shall submit a notice of the actual test date to the above address so that it is received at least two weeks prior to the test date.

(b) IDEM, OAQ, and VCAPC must receive all test reports within forty-five (45) days after the completion of the testing. IDEM, OAQ, and VCAPC may grant an extension, if the source submits to IDEM, OAQ, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

The documentation submitted by the Permittee does not require certification by the “authorized individual” as defined by 326 IAC 2-1.1-1.

Compliance Monitoring Requirements

C.11 Compliance Monitoring [326 IAC 2-1.1-11]

Compliance with applicable requirements shall be documented as required by this permit. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. All monitoring and record keeping requirements not already legally required shall be implemented when operation begins.

C.12 Maintenance of Monitoring Equipment [IC 13-14-1-13]

(a) In the event that a breakdown of the monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this permit until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less than one (1) hour until such time as the continuous monitor is back in operation.

(b) The Permittee shall install, calibrate, quality assure, maintain, and operate all necessary monitors and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.

C.13 Monitoring Methods [326 IAC 3]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, or other approved methods as specified in this permit.

C.14 Compliance Monitoring Plan - Failure to Take Response Steps [326 IAC 1-6] [326 IAC 2-2-4]

(a) The Permittee is required to implement a compliance monitoring plan to ensure that reasonable information is available to evaluate its continuous compliance with applicable requirements. This compliance monitoring plan is comprised of:

(1) This condition;

(2) The Compliance Determination Requirements in Section D of this permit;

(3) The Compliance Monitoring Requirements in Section D of this permit;

(4) The Record Keeping and Reporting Requirements in Section C (Monitoring Data Availability, General Record Keeping Requirements, and General Reporting Requirements) and in Section D of this permit; and

(5) A Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. CRP's shall be submitted to IDEM, OAQ, and VCAPC upon request and shall be subject to review and approval by IDEM, OAQ, and VCAPC. The CRP shall be prepared within ninety (90) days after the commencement of normal operation after the first phase of construction and shall be maintained on site, and is comprised of:

(A) Response steps that will be implemented in the event that compliance related information indicates that a response step is needed pursuant to the requirements of Section D of this permit; and

(B) A time schedule for taking such response steps including a schedule for devising additional response steps for situations that may not have been predicted.

(b) For each compliance monitoring condition of this permit, appropriate response steps shall be taken when indicated by the provisions of that compliance monitoring condition. Failure to perform the actions detailed in the compliance monitoring conditions or failure to take the response steps within the time prescribed in the Compliance Response Plan, shall constitute a violation of the permit unless taking the response steps set forth in the Compliance Response Plan would be unreasonable.

(c) After investigating the reason for the excursion, the Permittee is excused from taking further response steps for any of the following reasons:

(1) The monitoring equipment malfunctioned, giving a false reading. This shall be an excuse from taking further response steps providing that prompt action was taken to correct the monitoring equipment.

(2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for an administrative amendment to the permit, and such request has not been denied or;

(3) An automatic measurement was taken when the process was not operating; or

(4) The process has already returned to operating within “normal” parameters and no response steps are required.

(d) Records shall be kept of all instances in which the compliance related information was not met and of all response steps taken.

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate corrective actions. The Permittee shall submit a description of these corrective actions to IDEM, OAQ, and VCAPC within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize emissions from the affected emissions unit while the corrective actions are being implemented. IDEM, OAQ, and VCAPC shall notify the Permittee within thirty (30) days, if the corrective actions taken are deficient. The Permittee shall submit a description of additional corrective actions taken to IDEM, OAQ, and VCAPC within thirty (30) days of receipt of the notice of deficiency. IDEM, OAQ and VCPAC reserve the authority to use enforcement activities to resolve noncompliant stack tests.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ, and VCAPC that retesting in one hundred and twenty (120) days is not practicable, IDEM, OAQ and VCAPC may extend the retesting deadline. Failure of the second test to demonstrate compliance with the appropriate permit conditions may be grounds for immediate revocation of the permit to operate the affected emissions unit.

The documents submitted pursuant to this condition do not require the certification by the “authorized individual” as defined by 326 IAC 2-1.1-1.

Record Keeping and Reporting Requirements

C.16 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, including startups or shutdowns of any facility or emission control equipment, which result in violations of applicable air pollution control regulations or applicable emission limitations shall be kept and retained for a period of three (3) years and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), Vigo County Air Pollution Control (VCAPC), or appointed representative upon request.

(b) When a malfunction of any facility or emission control equipment occurs which lasts more than one (1) hour, said condition shall be reported to OAQ and VCAPC, using the Malfunction Report Forms (2 pages). Notification shall be made by telephone or facsimile, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of said occurrence.

(c) Failure to report a malfunction of any emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction shall be provided, including the items specified in 326 IAC 1-6-2(a)(1) through (6).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

C.17 Monitoring Data Availability [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) With the exception of performance tests conducted in accordance with Section C-Performance Testing, all observations, sampling, maintenance procedures, and record keeping, required as a condition of this permit shall be performed at all times the equipment is operating at normal representative conditions.

(b) As an alternative to the observations, sampling, maintenance procedures, and record keeping of subsection (a) above, when the equipment listed in Section D of this permit is not operating, the Permittee shall either record the fact that the equipment is shut down or perform the observations, sampling, maintenance procedures, and record keeping that would otherwise be required by this permit.

(c) If the equipment is operating but abnormal conditions prevail, additional observations and sampling should be taken with a record made of the nature of the abnormality.

(d) If for reasons beyond its control, the operator fails to make required observations, sampling, maintenance procedures, or record keeping, reasons for this must be recorded.

(e) At its discretion, IDEM and VCAPC may excuse such failure providing adequate justification is documented and such failures do not exceed five percent (5%) of the operating time in any quarter.

(f) Temporary, unscheduled unavailability of staff qualified to perform the required observations, sampling, maintenance procedures, or record keeping shall be considered a valid reason for failure to perform the requirements stated in (a) above.

C.18 General Record Keeping Requirements [326 IAC 2-6.1-2]

(a) Records of all required monitoring data and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years and available upon the request of an IDEM, OAQ, and VCAPC representative. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner or Vigo County Air Pollution Control makes a written request for records to the Permittee, the Permittee shall furnish the records to the Commissioner or Vigo County Air Pollution Control within a reasonable time.

(b) Records of required monitoring information shall include, where applicable:

    (1) The date, place, and time of sampling or measurements;

(2) The dates analyses were performed;

(3) The company or entity performing the analyses;

(4) The analytic techniques or methods used;

(5) The results of such analyses; and

(6) The operating conditions existing at the time of sampling or measurement.

(c) Support information shall include, where applicable:

(1) Copies of all reports required by this permit;

(2) All original strip chart recordings for continuous monitoring instrumentation;

(3) All calibration and maintenance records;

(4) Records of preventive maintenance shall be sufficient to demonstrate that failure to implement the Preventive Maintenance Plan did not cause or contribute to a violation of any limitation on emissions or potential to emit. To be relied upon subsequent to any such violation, these records may include, but are not limited to: work orders, parts inventories, and operator's standard operating procedures. Records of response steps taken shall indicate whether the response steps were performed in accordance with the Compliance Response Plan required by Section C - Compliance Monitoring Plan - Failure to take Response Steps, of this permit, and whether a deviation from a permit condition was reported. All records shall briefly describe what maintenance and response steps were taken and indicate who performed the tasks.

(d) All record keeping requirements not already legally required shall be implemented when operation begins.

C.19 General Reporting Requirements [326 IAC 2-1.1-11] [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) To affirm that the source has met all the compliance monitoring requirements stated in this permit the source shall submit a Semi-annual Compliance Monitoring Report. Any deviation from the requirements and the date(s) of each deviation must be reported. The Compliance Monitoring Report shall include the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

And

Vigo County Air Pollution Control
103 South Third Street
Terre Haute, IN 47807

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, and VCAPC on or before the date it is due.

(d) Unless otherwise specified in this permit, any semi-annual report shall be submitted within thirty (30) days of the end of the reporting period. The reports require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(e) All instances of deviations must be clearly identified in such reports. A reportable deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit or a rule. It does not include:

(1) An excursion from compliance monitoring parameters as identified in Section D of this permit unless tied to an applicable rule or limit; or

(2) A malfunction as described in 326 IAC 1-6-2; or

(3) Failure to implement elements of the Preventive Maintenance Plan unless lack of maintenance has caused or contributed to a deviation.

(4) Failure to make or record information required by the compliance monitoring provisions of Section D unless such failure exceeds 5% of the required data in any calendar quarter.

A Permittee's failure to take the appropriate response step when an excursion of a compliance monitoring parameter has occurred or failure to monitor or record the required compliance monitoring is a deviation.

(f) Any corrective actions or response steps taken as a result of each deviation must be clearly identified in such reports.

(g) The first report shall cover the period commencing on the date start of normal operation after the first phase of construction and ending on the last day of the reporting period.

SECTION D.1 FACILITY CONDITIONS – Simple Cycle Operation

Four (4) natural gas-fired combustion turbines designated as units CT11, CT12, CT21, CT22, with a maximum heat input capacity of 1,490.5 MMBtu/hr (per unit on a lower heating value basis), and exhausts to stacks designated as E11B, E12B, E21B and E22B, respectively, for use when operating in simple cycle. (The information describing the process contained in this facility description box is descriptive information, and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1.1 Prevention of Significant Deterioration [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD), this new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X, and VOC because the potential to emit for these pollutants exceed the PSD major significant thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

D.1.2 Particulate Matter (PM and PM_{10}) Emission Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements) the total PM, is the sum of filterable PM, and PM_{10} (filterable and condensible), emissions from each combustion turbine stack shall not exceed 0.012 pounds per MMBtu on a lower heating value basis, which is equivalent to eighteen (18) pounds per hour for each combustion turbine.

D.1.3 Opacity Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements) the opacity from each associated combustion turbine stack shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

D.1.4 Startup and Shutdown Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), a startup or shutdown is defined as operation less than fifty (50) percent load. Each combustion turbine-generating unit shall comply with the following:

(a) A startup or shutdown period shall not exceed two (2) hours. Each turbine shall not exceed 250 hours per year for startups and 42 hours per year for shutdowns.

(b) The NO_X emissions from each combustion turbine stack shall not exceed 32.5 tons per year for startup and shutdown emissions. Each combustion turbine shall not exceed 80 ppmvd corrected to 15% O_2 during startup and 48 ppmvd corrected to 15% O_2 during shutdown, averaged over the duration of the startup or shutdown.

(c) The CO emissions from each combustion turbine stack shall not 41.3 tons per year for startup and shutdown emissions. Each combustion turbine shall not exceed 150 ppmvd corrected to 15% O_2 during startup, and 90 ppmvd corrected to 15% O_2 during shutdown, averaged over the duration of the startup or shutdown.

D.1.5 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) each combustion turbine generating unit shall comply with the following, excluding startup and shutdown:

(1) During normal simple cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine shall not exceed 9.0 ppmvd corrected to fifteen (15) percent oxygen, based on a three (3) hour averaging period, which is equivalent to 54.0 pounds per hour for each combustion turbine.

(2) Each combustion turbine shall be equipped with dry low-NO_X combustors and operated using good combustion practices to control NO_X emissions.

(3) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from each of the four (4) combustion turbines, excluding startup and shutdown emissions, shall not exceed 236.52 tons per year.

D.1.6 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine shall comply with the following, excluding startup and shutdown:

(1) During normal simple cycle operation (fifty (50) percent load or more), the CO emissions from each combustion turbine shall not exceed 9 ppmvd corrected to fifteen (15) percent oxygen, based on a 24 hour averaging period, which is equivalent to 26.4 pounds per hour from each combustion turbine.

(2) Good combustion practices shall be applied to minimize CO emissions.

(3) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from each of the four (4) combustion turbines, excluding startup and shutdown emissions, shall not exceed 115.63 tons per year.

D.1.7 Sulfur Dioxide (SO_2) Emission Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine shall comply with the following, excluding startup and shutdown:

(1) During normal simple cycle operation (fifty (50) percent load or more), the SO_2 emissions from each combustion turbine shall not exceed 0.0028 pounds per MMBtu on a lower heating values basis, which is equivalent to 4.2 pounds per hour from each combustion turbine.

(2) The use of low sulfur natural gas as the only fuel for the four (4) combustion turbines.

The sulfur content of the natural gas shall not exceed 0.007 percent by weight (two (2) grains per 100 scf)

(3) Perform good combustion practices.

D.1.8 Volatile Organic Compound (VOC) Emission Limitations for Combustion Turbines

Pursuant to 326 IAC 8-1-6 (VOC BACT Requirements), the following requirements must be met, excluding startup and shutdown:

(1) The VOC emissions form each combustion turbine shall not exceed 0.0024 pounds per MMBtu on a lower heating value basis, which is equivalent to 3.7 pounds VOC per hour for each combustion turbine.

(2) The use of natural gas as the only fuel

(3) Good combustion practice shall be implemented to minimize VOC emissions.

D.1.9 40 CFR 60, Subpart GG (Stationary Gas Turbines)

The four (4) natural gas combustion turbines are subject to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions from the natural gas turbines to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

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

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

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

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight; Compliance with Condition D.1.7 constitutes compliance with this requirement.

D.1.10 Formaldehyde Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the formaldehyde emissions form each combustion turbine stack shall not exceed 0.00036 pounds of formaldehyde per MMBtu on a lower heating value basis.

D.1.11 Operational Limitation

Pursuant to 326 IAC 2-2 (PSD Requirements), conditions contained within this section of the permit

(D.1 Simple Cycle Operation) shall be followed (per turbine) when combustion turbine exhaust is routed through the integral bypass stack designated as E11B, E12B, E21B, and E22B. During periods when turbine exhaust is not routed through the integral bypass stacks (E11B, E12B, E21B, and E22B), the Permittee shall follow the conditions contained in Section D.2 Combined Cycle Operation.

D.1.12 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for each combustion turbine.

Compliance Determination Requirements

D.1.13 Performance Testing

(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, not later than one-hundred and eighty days (180) after a facility startup or monitor installation, on the combustion turbine exhaust stacks (E11B, E12B, E21B, and E22B) in order to certify continuous emission monitoring systems for NO_X and CO.

(b) Within sixty (60) days after initial startup, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde test for each combustion turbine stack (E11B, E12B, E21B, and E22B) utilizing methods approved by the Commissioner when operating 60%, 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to verify the formaldehyde emission factor as specified in Condition D.1.10.

(c) Within sixty (60) days after initial startup, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall perform NO_X and CO stack tests for each turbine (stacks designated as E11B, E12B, E21B, and E22B) during a startup/shutdown period, utilizing methods as approved by the Commissioner. These tests shall be performed in accordance with Section C – Performance Testing, in order to document compliance with Condition D.1.4.

(d) Within sixty (60) days after achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall conduct NO_X and SO_2 stack tests for each turbine utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with Condition D.1.9.

(e) Within sixty (60) days after initial startup, but no later than one-hundred eighty (180) after initial startup, the Permittee shall perform PM, PM_{10} (filterable and condensible), and VOC stack tests for each combustion turbine stack (E11B, E12B, E21B, and E22B) utilizing methods approved by the Commissioner. These test shall be performed in accordance with Section C – Performance Testing, in order to document compliance with Condition D.1.2 and D.1.8(1).

(f) IDEM, OAQ and VCAPC retain the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary.

D.1.14 40 CFR Part 60, Subpart GG Compliance Requirements (Stationary Gas Turbines)

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines), the Permittee shall monitor the nitrogen and sulfur content of the natural gas on a monthly basis as follows:

(a) Determine compliance with the nitrogen oxide and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a), per requirements described in 40 CFR 60.335(c);

(b) Determine the sulfur content of the natural gas being fired in the turbine by ASTM Methods D 1072-80, D 3030-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator; and

(c) Determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator.

The analyses required above 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.

Owners, operators or fuel vendors may develop custom fuel schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the above requirements.

D.1.15 Continuous Emission Monitoring

(a) The owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2, shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for each combustion turbine stack for NO_X, CO, and O_2 (E11B, E12B, E21B and E22B) in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour, uncorrected parts per million, and parts per million on a dry volume basis (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NO_X and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a three (3) hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a twenty four (24) hour averaging period. The source shall maintain records of the ppmvd corrected to 15% O_2 and the pounds per hour.

(2) The Permittee shall determine compliance with Conditions D.1.4 utilizing data from the NO_X, CO, and O_2 CEMS, the fuel flow meter, and Method 19 calculations.

(3) The Permittee shall submit to IDEM, OAQ, and VCAPC within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating

procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(4) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.16 Record Keeping Requirements

(a) To document compliance with Condition D.1.2, D.1.5 through D.1.9, and D.1.11, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMCF) per turbine during each month

(2) The percent sulfur content of the natural gas

(3) The average heat input, on a lower heating value basis, of each turbine on a 30-day rolling average.

(b) To document compliance with Condition D.1.4, the Permittee shall maintain records of the following:

(1) The type of operation (i.e., startup or shutdown) with supporting operational data

(2) The total number of minutes for startup or shutdown per 24-hour period per turbine

(3) The CEMS data, fuel flow meter data, and Method 19 calculations corresponding to each startup and shutdown period.

(c) To document compliance with Conditions D.1.5 and D.1.6, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and ppmvd corrected to 15% oxygen.

(d) To document compliance with Condition D.1.15, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date as described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(e) To document compliance with Condition D.1.9, the source shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(f) A record of the hours of operation per year per turbine for simple cycle operation shall be maintained.

(g) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit

D.1.17 Reporting Requirements

The Permittee shall submit the following information on a quarterly basis:

(a) Records of excess NO_X and CO emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system for each parameter described in Condition D.1.15. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C – General Reporting Requirements of this permit.

(b) The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c)

(c) A quarterly summary of the CEMs data to document compliance with D.1.5(a)(1) and D.1.6(a)(1) shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

(d) A quarterly summary of the total number of startup and shutdown hours of operation and emissions corresponding to startup and shurtdown to document compliance with Condition D.1.4, shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

SECTION D.2 FACILITY CONDITIONS – Combined Cycle Operation

(a) Four (4) natural gas-fired combustion turbines, designated as units CT11, CT12, CT21, CT22, with a maximum heat input capacity of 1,490.5 MMBtu/hr (per unit on a lower heating value basis), and exhausts to stacks designated as E11B, E12B, E21B and E22B, respectively, for use when operating in simple cycle. During combined cycle operation exhaust goes to stacks designated E11A, E12A, E21A and E22A, respectively.

(b) Four (4) duct burners, designated as units DB11, DB12, DB21, DB22, with a maximum heat input capacity of 300 MMBtu/hr (per unit on a higher heating value basis) each and exhausts to stacks designated E11A, E12A, E21A, E22A, respectively.

(c) Four (4) heat recovery steam generators, designated as units HRSG11, HRSG12, HRSG21, HRSG22.

(d) Four (4) selective catalytic reduction systems, designated as units SCR11, SCR12, SCR21, SCR22.

(e) Two (2) cooling towers, designated as units COOL1 and COOL2, exhausts to stacks designated E3 and E4, respectively.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.2.1 Prevention of Significant Deterioration [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD), this new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X, and VOC because the potential to emit for these pollutants exceed the PSD major significant thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

D.2.2 Particulate Matter (PM/PM_{10}) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM is the sum of PM (filterable) and PM_{10} (filterable and condensible), emissions from each combustion turbine shall not exceed 0.012 pounds per MMBtu (on a lower heating value basis) which is equivalent to eighteen (18) pounds per hour for each combustion turbine.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM, sum of PM (filterable) and PM_{10} (filterable and condensible), emissions from each duct burner shall not exceed 0.0075 pounds per MMBtu on a higher heating value basis, which is equivalent to 2.2 pounds per hour.

(c) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM is the sum of PM (filterable) and PM_{10} (filterable and condensible), emissions from each combustion turbine when its associated duct burner is operating, shall not exceed 20.2 pounds per hour for each combustion turbine and duct burner.

D.2.3 Opacity Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements) the opacity from each associated combustion turbine stack shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

D.2.4 Particulate Matter Emissions (PM/PM_{10}) for Cooling Towers

Pursuant to 326 IAC 2-2 (PSD Requirements) each cooling tower shall comply with the following:

(1) PM emissions shall not exceed 1.41 pounds per hour, and

(2) Employ good design and operation practices to limit emissions from the cooling towers.

(3) For compliance purposes, cooling tower PM emissions shall be calculated using emission factors from USEPA AP-42 Section 13.4.

D.2.5 Startup and Shutdown Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), a startup or shutdown is defined as less than fifty (50) percent load. Each combustion turbine generating unit shall comply with the following:

(a) Each startup or shutdown period shall not exceed four (4) hours. Each turbine shall not exceed 500 hours per year for startups and 83 hours per year for shutdowns.

(b) The NO_X emissions from each combustion turbine stack shall not exceed 64.9 tons per year for startup and shutdown emissions. Each combustion turbine shall not exceed 80 ppmvd corrected to 15% O_2 during startup, and 48 ppmvd corrected to 15% O_2 shutdown, averaged over the duration of the startup or shutdown.

(c) The CO emissions from each combustion turbine stack shall not exceed 82.5 tons per year for startup and shutdown emissions. Each combustion turbine shall not exceed 150 ppmvd corrected to 15% O_2 during startup, and 90 ppmvd corrected to 15% O_2 shutdown, averaged over the duration of the startup or shutdown.

D.2.6 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) each combustion turbine/steam generating unit shall comply with the following, excluding startup and shutdown:

(1) During normal combined cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine stack shall not exceed 3.0 ppmvd corrected to fifteen (15) percent oxygen, based on a three (3) hour averaging period, which is equivalent to 17.89 pounds per hour for each combustion turbine.

(2) During normal combined cycle operation (fifty (50) percent load or more), the NO_X emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 3.0 ppmvd corrected to fifteen (15) percent oxygen, based on a three (3) hour averaging period, which is equivalent to 18 pounds per hour for

each combustion turbine and duct burner.

(3) The duct burners shall not be operated until normal operation begins.

(4) Each combustion turbine shall be equipped with dry low-NO_X burners and operated using good combustion practices to control NO_X emissions.

(5) A selective catalytic reduction (SCR) system shall be installed and operated at all times, except during periods of startup and shutdown, to control NO_X emissions.

(6) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from each of the four (4) combustion turbines and associated duct burners, excluding startup and shutdown emissions, shall not exceed 78.36 tons per year.

D.2.7 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each steam generating unit shall comply with the following, excluding startup and shutdown:

(1) During normal combined cycle operation (fifty (50) percent load or more), the CO emissions from each combustion turbine shall not exceed 9 ppmvd corrected to 15% O_2 on a 24 hour averaging period, which is equivalent to 26.4 pounds per hour for each combustion turbine.

(2) During normal operation (fifty (50) percent load of more), the CO emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 14 ppmvd corrected to 15% O_2 on a 24 hour averaging period, which is equivalent to 51.0 pounds per hour for each combustion turbine and duct burner.

(3) The duct burners shall not be operated until normal operation begins.

(4) Good combustion practices shall be applied to minimize CO emissions.

(5) Use natural gas as the only fuel

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from each of the four (4) combustion turbines and associated duct burners, excluding startup and shutdown emissions, shall not exceed 131.86 tons per year.

D.2.8 Sulfur Dioxide (SO_2) Emission Limitations for Combustion Turbines/Duct Burners

Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine and duct burner shall comply with the following, excluding startup and shutdown:

(1) During normal combined cycle operation (fifty (50) percent load or more), the SO_2 emissions from each combustion turbine shall not exceed 0.0028 pounds per MMBtu on a lower heating value basis, which is equivalent to 4.2 pounds per hour for each combustion turbine.

(2) During normal operation of each duct burner, the SO_2 emissions shall not exceed 0.001 pounds per MMBtu on a higher heating value basis, which is equivalent to 0.2 pounds per hour for each combustion turbine.

(3) During normal combined cycle operation of each combustion turbine when its associated duct burner is operating, the SO_2 emissions from each turbine stack shall 4.4 pounds per hour.

(4) The use of low sulfur natural gas as the only fuel for the combustion turbines and duct burners. The sulfur content of the natural gas shall not exceed 0.007 percent by weight (two (2) grains per 100 scf).

(5) Perform good combustion practice.

D.2.9 Volatile Organic Compound (VOC) Emission Limitations for Combustion Turbines/Duct Burners

Pursuant to 326 IAC 8-1-6 (VOC Requirements) and 326 2-2 (PSD Requirements), the following requirements must be met, excluding startup and shutdown:

(1) The VOC emissions from each combustion turbine shall not exceed 0.0025 pounds per MMBtu on a lower heating value basis, which is equivalent to 3.7 pounds VOC per hour for each combustion turbine.

(2) The VOC emissions from each duct burner shall not exceed 0.005 pounds per MMBtu on a higher heating value basis, which is equivalent to 1.6 pounds VOC per hour.

(3) The VOC emissions from each combustion turbine stack, when its associated duct burner is operating shall not 5.3 pounds of VOC per hour.

(4) The use of natural gas as the only fuel.

(5) Good combustion practice shall be implemented to minimize VOC emissions.

D.2.10 40 CFR 60, Subpart GG (Stationary Gas Turbines)

The four (4) natural gas combustion turbines are subject to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions from the natural gas turbines to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

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

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

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

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight; Compliance with Condition D.2.8 constitutes compliance with this condition.

D.2.11 40 CFR Part 60, Subpart Da (Electric Utility Steam Generating Units)

The heat recovery steam generator (HRSG) duct burners (DB) are subject to 40 CFR Part 60, Subpart Da because the heat input capacity is greater than 250 MMBtu/hr on a higher heating value basis.

Pursuant to 40 CFR Part 60, Subpart Da, the Permittee shall:

(a) The opacity from each combustion turbine stack, when its associated duct burner is operating, shall not exceed twenty (20) percent (6-minute average), except for on 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

(b) The PM emissions from each duct burner shall not exceed 0.03 pounds per MMBtu heat input on a higher heating value basis. Compliance with Condition D.2.2 constitutes compliance with this condition.

(c) Each duct burner shall not exceed 1.6 lb/MW-hr NO_X, on a thirty (30) day rolling average.

(d) Each duct burner shall not exceed 0.20 pounds SO_2 per MMBtu heat input, determined on a 30-day rolling average basis. Compliance with condition D.2.8 constitutes compliance with this condition.

D.2.12 Formaldehyde Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the formaldehyde emissions from each combustion turbine and duct burner shall not exceed 0.00036 pounds of formaldehyde per MMBtu, excluding startup and shutdown.

D.2.13 Ammonia Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the ammonia emissions from each combustion turbine stack shall not exceed ten (10) ppmvd corrected to 15% O_2.

D.2.14 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for each combustion turbine and its control device.

Compliance Determination Requirements

D.2.15 Performance Testing

(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, no later than one-hundred and eighty days (180) after the facility startup or monitor installation, on the combustion turbine exhaust stack (E11A, E12A, E21A, and E22A) in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within sixty (60) days after initial startup, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde stack test for each combustion turbine stack (E11A, E12A, E21A, and E22A) utilizing a method approved by the Commissioner when operating at 60%, 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to verify the formaldehyde emission factor specified in condition D.2.12.

(c) Within sixty (60) days after initial startup, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall perform NO_X and CO stack tests for each combustion turbine stack (E11A, E12A, E21A, and E22A) during a startup/shutdown period, utilizing methods approved by the Commissioner. These tests shall be performed in accordance with Section C – Performance Testing, in order to document compliance with Conditions D.2.5.

(d) Within sixty (60) days of achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall conduct NO_X and SO_2 stack tests for each combustion turbine stack (E11A, E12A, E21A, and E22A) utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with Condition D.2.10.

(e) Within sixty (60) days after initial startup, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall perform PM, PM_{10} (filterable and condensible), ammonia, and VOC stack tests for each combustion turbine stack (E11A, E12A, E21A, and E22A) utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335, 40 CFR 60.48(a), and Section C – Performance Testing, in order to document compliance with D.2.2(b), D.2.9, and D.2.13.

(f) IDEM, OAQ and VCAPC retain the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary.

D.2.16 40 CFR Part 60, Subpart GG Compliance Requirements (Stationary Gas Turbines)

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines), the Permittee shall monitor the nitrogen and sulfur content of the natural gas on a monthly basis as follows:

(a) Determine compliance with the nitrogen oxide and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a), per requirements described in 40 CFR 60.335(c);

(b) Determine the sulfur content of the natural gas being fired in the turbine by ASTM Methods D 1072-80, D 3030-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator; and

(c) Determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator.

The analyses required above 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.

Owners, operators or fuel vendors may develop custom fuel schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the above requirements.

D.2.17 Continuous Emission Monitoring (CEMs)

(a) The owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2, shall be required to install a continuos emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO, for stacks designated as E11A, E12A, E21A and E22A in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NO_X and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limit, the source shall take an average of the parts per million (ppmvd) corrected to 15% O_2 over a three (3) hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppmvd) corrected to 15% O_2 over a twenty four (24) hour averaging period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall determine compliance with Condition D.2.5 utilizing data from the NO_X, CO, and O_2 CEMS, the fuel flow meter, and Method 19 calculations.

(3) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(4) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(c) Pursuant to 40 CFR 60.47(d), the Permittee shall install, calibrate, certify and operate continuous emissions monitors for carbon dioxide or oxygen at each location where nitrogen oxide emissions are monitored.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.2.18 Record Keeping Requirements

(a) To document compliance with Conditions D.2.2, D.2.5 through D.2.8, and D.2.11, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMCF) per turbine during each month.

(2) Percent sulfur of the natural gas.

(3) Heat input on a lower heating value basis of each turbine on a 30-day rolling average.

(b) To document compliance with Condition D.2.5, the Permittee shall maintain records of the following:

(1) The type of operation (i.e. startup or shutdown) with supporting operational data

(2) The total number of minutes for startup or shutdown per 24-hour averaging period per turbine

(3) The CEMS data, fuel flow meter data, and Method 19 calculations corresponding to each startup and shutdown period.

(c) To document compliance with Conditions D.2.6 and D.2.7, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and parts per million (ppmvd) corrected to 15% oxygen.

(d) To document compliance with Condition D.2.18, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(e) To document compliance with D.2.10, the Permittee shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(f) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

D.2.19 Reporting Requirements

The Permittee shall submit the following information on a quarterly basis:

(a) Records of excess NO_X and CO emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C – General Reporting Requirements of this permit.

(b) The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c)

(c) A quarterly summary of the CEMs data to document compliance with D.2.6, and D.2.7 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

(d) A quarterly summary of the total number of startup and shutdown hours of operation and corresponding startup and shutdown emissions to document compliance with Condition D.2.5, shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

SECTION D.3 FACILITY CONDITIONS – Auxiliary Boilers

Two (2) natural gas fired auxiliary boilers, designated AB1 and AB2, with a maximum heat input capacity of 35 MMBtu/hr (per unit on a higher heating value basis), and exhausts to stacks E5 and E6 respectively. (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.3.1 Prevention of Significant Deterioration [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD), this new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X, and VOC because the potential to emit for these pollutants exceed the PSD major significant thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

D.3.2 Particulate Matter Emissions (PM/PM_{10}) for Auxiliary Boilers

Pursuant to 326 IAC 2-2 (PSD Requirements) each auxiliary boiler shall comply with the following:

(a) Emissions from each auxiliary boiler shall not exceed 0.008 lb/MMBtu on a higher heating value basis, which is equivalent to 0.28 pounds per hour for each auxiliary boiler.

(b) Use natural gas as the only fuel for the auxiliary boilers.

(c) Perform good combustion practices

D.3.3 Opacity Limitations

Pursuant to 326 IAC 5-1-2, the Permittee shall not cause the average opacity of either auxiliary boiler stacks to exceed twenty percent (20%) in any one (1) six (6) minute period. The opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

D.3.4 Nitrogen Oxide (NO_X) Emission Limitations for Auxiliary Boilers

Pursuant to 326 IAC 2-2 (PSD Requirements), each auxiliary boiler shall comply with the following:

(a) NO_X emissions from each auxiliary boiler shall not exceed 0.049 lb/MMBtu on a higher heating value basis, which is equivalent to 1.72 pounds per hour for each auxiliary boiler.

(b) Use natural gas as the only fuel for the auxiliary boilers.

(c) Operate auxiliary boilers using low-NOx burners.

D.3.5 Carbon Monoxide (CO) Emission Limitations for Auxiliary Boilers

Pursuant to 325 IAC 2-2 (PSD Requirements) each auxiliary boiler shall comply with the following:

(a) CO emissions from each auxiliary boiler shall not exceed 0.824 lb/MMBtu on a higher heating value basis, which is equivalent to 2.88 pounds per hour for each auxiliary boiler.

(b) Use natural gas as the only fuel for the auxiliary boilers.

(c) Operate utilizing good combustion practices.

D.3.6 Sulfur Dioxide (SO_2) Emission Limitations for Auxiliary Boiler

Pursuant to 326 IAC 2-2 (PSD Requirements) each auxiliary boiler shall comply with the following:

(a) SO_2 emissions from each auxiliary boiler shall not exceed 0.0006 lb/MMBtu on a higher heating value basis, which is equivalent to 0.021 pounds per hour for each auxiliary boiler.

(b) Use natural gas, with a sulfur content of less than or equal to 0.8 percent by weight, as the only fuel for the auxiliary boilers.

(c) Operate utilizing good combustion practices.

D.3.7 Volatile Organic Compound (VOC) Emission Limitations for Auxiliary Boilers

Pursuant to 326 IAC 2-2 (PSD Requirements) and 326 IAC8-1-6 (General Reduction Requirements) each auxiliary boiler shall comply with the following:

(a) VOC emissions from each auxiliary boiler shall not exceed 0.0054 lb/MMBtu on a higher heating value basis, which is equivalent to 0.19 pounds per hour for each auxiliary boiler.

(b) Use natural gas as the only fuel for the auxiliary boilers.

(c) Operate using good combustion practices.

D.3.8 Natural Gas Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements), the combined natural gas usage from the auxiliary boilers shall not exceed 343.2 MMSCF per year per year, based on a twelve (12) consecutive month period.

D.3.9 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit.

Compliance Determination Requirements

D.3.10 Performance Testing

For compliance purposes auxiliary boiler emissions shall be calculated using the emission factors for small boilers with low NO_X burners in USEPA's AP-42 Section 1.4 (07/1998) and the measured heating value.

(a) IDEM, OAQ and VCAPC retain the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.3.11 Record Keeping Requirements

(a) To document compliance with Conditions D.3.6, the Permittee shall maintain records of the amount of natural gas combusted for each auxiliary boiler during each month.

(b) All records shall be maintained in accordance with Section C – General Record Keeping Requirements.

D.3.12 Reporting Requirements

The Permittee shall submit the following information on a quarterly basis a summary of the information to document compliance with Condition D.3.6 shall be submitted to the addresses listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

SECTION D.4 FACILITY CONDITIONS – Backup Equipment

(a) Two (2) diesel fire pumps, with a rating of 267 horsepower (hp). (b) Two (2) diesel emergency generators, with a rating of 1,475 horsepower (hp). (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.4.1 BACT Limitation for Fire Pumps

Pursuant to 326 IAC 2-2 (PSD Requirements) the two (2) diesel fire pumps shall comply with the following:

(a) The total input of the fire pumps shall be limited to 6,569 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used by the fire pump shall not exceed 0.05 percent by weight.

(c) Perform good combustion practice.

D.4.2 BACT Limitation for Emergency Generators

Pursuant to 326 IAC 2-2 (PSD Requirements) the two (2) emergency generators shall comply with the following:

(a) The total input of the fire pumps shall be limited to 37,847 gallons per twelve (12) consecutive month period, rolled on a monthly basis.

(b) The sulfur content of the diesel fuel used by the fire pump shall not exceed 0.05 percent by weight.

(c) Perform good combustion practice.

Compliance Determination Requirements

D.4.3 Performance Testing

The Permittee is not required to test these emissions units by this permit. However, IDEM may require compliance testing when necessary to determine if the emissions unit is in compliance. If testing is required by IDEM or VCAPC, compliance shall be determined by a performance test conducted in accordance with Section C - Performance Testing.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.4.4 Record Keeping Requirements

To document compliance with Conditions D.4.1 and D.4.2, the Permittee shall maintain records of the following:

(1) Amount of diesel fuel combusted each month in the two (2) fire pumps.

(2) Amount of diesel fuel combusted each month in the two (2) emergency generators.

(3) The percent sulfur content of the diesel fuel.

D.4.5 Reporting Requirements

A quarterly summary of the information to document compliance with D.4.1 and D.4.2 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
FAX NUMBER - 317 233-5967

This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

THIS FACILITY MEETS THE APPLICABILITY REQUIREMENTS BECAUSE IT HAS POTENTIAL TO EMIT 25 LBS/HR PARTICULATE MATTER ?_____, 100 LBS/HR VOC ?_____, 100 LBS/HR SULFUR DIOXIDE ?_____ OR 2000 LBS/HR OF ANY OTHER POLLUTANT ?_____ EMISSIONS FROM MALFUNCTIONING CONTROL EQUIPMENT OR PROCESS EQUIPMENT CAUSED EMISSIONS IN EXCESS OF APPLICABLE LIMITATION ________.

THIS MALFUNCTION RESULTED IN A VIOLATION OF: 326 IAC _______ OR, PERMIT CONDITION # _______ AND/OR PERMIT LIMIT OF _______________

THIS INCIDENT MEETS THE DEFINITION OF 'MALFUNCTION' AS LISTED ON REVERSE SIDE ? Y N

THIS MALFUNCTION IS OR WILL BE LONGER THAN THE ONE (1) HOUR REPORTING REQUIREMENT ? Y N

COMPANY:____PHONE NO. ( )________________________
LOCATION: (CITY AND COUNTY)____
PERMIT NO. _________________ AFS PLANT ID: _________________ AFS POINT ID: _________________ INSP:___________
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON:____________________________________
____

DATE/TIME MALFUNCTION STARTED: _____/_____/ 20____ ____________________________________ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION: ______________________________

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE______/______/ 20____ _______________ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO2, VOC, OTHER:_________________________________

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: ______________________________
____

MEASURES TAKEN TO MINIMIZE EMISSIONS:____
____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

CONTINUED OPERATION REQUIRED TO PROVIDE ESSENTIAL* SERVICES:______________________________
CONTINUED OPERATION NECESSARY TO PREVENT INJURY TO PERSONS:______________________________
CONTINUED OPERATION NECESSARY TO PREVENT SEVERE DAMAGE TO EQUIPMENT:___________________
INTERIM CONTROL MEASURES: (IF APPLICABLE)____
____
____

MALFUNCTION REPORTED BY:_______________________________TITLE:_________________________
(SIGNATURE IF FAXED)

MALFUNCTION RECORDED BY:______________________DATE:_________________TIME:__________________

Please note - This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1 or 326 IAC 2-6.1.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

***Essential services** are interpreted to mean those operations, such as, the providing of electricity by power plants. Continued operation solely for the economic benefit of the owner or operator shall not be sufficient reason why a facility cannot be shutdown during a control equipment shutdown.

If this item is checked on the front, please explain rationale:

____

____

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section and Vigo County Air Pollution Control

Quarterly Report

Company Name: Mirant Sugar Creek LLC
Location: 6500 Darwin Road, West Terre Haute, IN 47885
Permit No.: CP-167-12208-00123
Source: Two Auxiliary Boilers
Limit: 343.2 MMCF per twelve (12) consecutive month period

Year: ____________

Month	Usage (MMCF/month)	Usage for previous month(s) (MMCF)	Usage for twelve month period (MMCF)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section and Vigo County Air Pollution Control

Quarterly Report

Company Name: Mirant Sugar Creek LLC
Location: 6500 Darwin Road, West Terre Haute, IN 47885
Permit No.: CP-167-12208-00123
Source: Two (2) emergency diesel fire pump
Limit: 6,569 gallons per twelve (12) consecutive month period

Year: ____________

Month	Diesel Fuel Oil Usage (gallons/month)	Diesel Fuel Oil Usage for previous month(s) (gallons)	Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section and Vigo County Air Pollution Control

Quarterly Report

Company Name: Mirant Sugar Creek LLC
Location: 6500 Darwin Road, West Terre Haute, IN 47885
Permit No.: CP-167-12208-00123
Source: Two (2) emergency generators
Limit: 37,847 gallons per twelve (12) consecutive month period

Year: ____________

Month	Diesel Fuel Oil Usage (gallons/month)	Diesel Fuel Oil Usage for previous month(s) (gallons)	Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section and Vigo County Air Pollution Control

Quarterly Report

Company Name: Mirant Sugar Creek LLC
Location: 6500 Darwin Road, West Terre Haute, IN 47885
Permit No.: CP-167-12208-00123
Source: Four (4) natural gas combustion turbines operating in simple cycle
Limit: Two (2) hours per startup, and 250 hours per year for startups. Two (2) hours per shutdown, and 42 hours per year for shutdowns.

Month:__________ Year__________
Total hours from previous month(s) startup________________ shutdown______________
Total hours per year for startup and shutdown for 12 month period__________

	Startup				Shutdown					Startup				Shutdown			
Day/ Turbine	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**Day/ Turbine**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
1									**17**								
2									**18**								
3									**19**								
4									**20**								
5									**21**								
6									**22**								
7									**23**								
8									**24**								
9									**25**								
10									**26**								
11									**27**								
12									**28**								
13									**29**								
14									**30**								
15									**31**								
16									**Total**								

No deviation occurred in this month

Deviation/s occurred in this month.
Deviation has been reported on:

Submitted by: ______________________________
Title/Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section and Vigo County Air Pollution Control

Quarterly Report

Company Name: Mirant Sugar Creek LLC
Location: 6500 Darwin Road, West Terre Haute, IN 47885
Permit No.: CP-167-12208-00123
Source: Four (4) natural gas combustion turbines operating in combined cycle
Limit: Four (4) hours per startup, and 500 hours per year for startups. Four (4) hours per shutdown, and 83 hours per year for shutdowns.

Month:__________ Year__________

Total hours from previous month(s) startup________________ shutdown_______________

Total hours per year for startup and shutdown for 12 month period__________

	Startup				Shutdown					Startup				Shutdown			
Day/ Turbine	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**Day/ Turbine**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
1									**17**								
2									**18**								
3									**19**								
4									**20**								
5									**21**								
6									**22**								
7									**23**								
8									**24**								
9									**25**								
10									**26**								
11									**27**								
12									**28**								
13									**29**								
14									**30**								
15									**31**								
16									**Total**								

No deviation occurred in this month

Deviation/s occurred in this month.
Deviation has been reported on:

Submitted by: ______________________________
Title/Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Mail to: Permit Administration & Development Section
Office of Air Quality
100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015

Mirant Sugar Creek LLC
115 Perimeter Center West
Atlanta, GA 30338-4780

Affidavit of Construction

I, ______________________________, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ______________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of __________________ for __________________.
(Title) (Company Name)

3. By virtual of my position with ______________________,I have personal
(Company Name)

knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of ______________________________ .
(Company Name)

4. I hereby certify that Mirant Sugar Creek LLC, 6500 Darwin Road, West Terre Haute, Indiana, 47885, completed construction of the natural gas merchant power plant on ________________in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on April 24, 2000 and as permitted pursuant to **Construction Permit No. CP-167-12208, Plant ID No. 167-00123** issued on

5. I hereby certify that Mirant Sugar Creek LLC is now subject to the Title V program and will submit a Title V operating permit application within twelve (12) months from the postmarked submission date of this Affidavit of Construction.

Further Affiant said not.
I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature

Date

STATE OF INDIANA)
)SS

COUNTY OF ________________)

Subscribed and sworn to me, a notary public in and for ____________________ County and State of Indiana on this ______________ day of ________________, 20 _______ .

My Commission expires:

Signature

Name (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for New Construction and P.S.D. Operation

Source Background and Description

Source Name:	Mirant Sugar Creek LLC
Source Location:	6500 Darwin Road, West Terre Haute, IN 47885
County:	Vigo
Construction Permit No.:	CP-167-12208-00123
SIC Code:	4911
Permit Reviewer:	David Howard

The Office of Air Quality (OAQ) has reviewed an application from Mirant Sugar Creek LLC (Mirant) relating to the construction and operation of the Mirant Sugar Creek Power Plant. The proposed plant will be a 1,008 megawatt (MW) electric generating station. The permit specifies that the combustion turbine generators will fire only natural gas. Any addition of a backup fuel in the future will require a modification to the permit and, if applicable, go through Prevention of Significant Deterioration (PSD) review. The source will consist of the following equipment:

(a) Four (4) natural gas-fired combustion turbine generators, designated as units CT11, CT12, CT21, CT22, each with a maximum heat input capacity of 1,490.5 MMBtu/hr (per unit on a lower heating value basis), and exhausting to stacks designated as E11B, E12B, E21B and E22B, respectively, for use when operating in simple cycle operation. During combined cycle operation the combustion turbine generators exhaust to stacks designated E11A, E12A, E21A and E22A, respectively.

(b) Four (4) duct burners, designated as units DB11, DB12, DB21, DB22, each with a maximum heat input capacity of 300 MMBtu/hr on a higher heating value basis and exhausting to stacks designated E11A, E12A, E21A, E22A, respectively.

(c) Four (4) heat recovery steam generators, designated as units HRSG11, HRSG12, HRSG21, HRSG22.

(d) Four (4) selective catalytic reduction systems, designated as units SCR11, SCR12, SCR21, SCR22.

(e) Two (2) natural gas fired auxiliary boilers, designated AB1 and AB2, with a maximum heat input capacity of 35 MMBtu/hr (per unit on a higher heating value basis), and exhausting to stacks E5 and E6 respectively.

(f) Two (2) steam turbines, designated as units ST1 and ST2.

(g) Two (2) cooling towers, designated as units COOL1 and COOL2, exhausting to stacks designated E3 and E4, respectively.

(h) Two (2) diesel fire pumps, each with a rated capacity of 267 horsepower (hp).

(i) Two (2) diesel backup electric generators, each with a rated capacity of 1475 horsepower (hp).

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)
E11A	CT11,DB11	170	16.75	1,070,917	182.8
E12A	CT12,DB12	170	16.75	1,070,917	182.8
E21A	CT21,DB21	170	16.75	1,070,917	182.8
E22A	CT22,DB22	170	16.75	1,070,917	182.8
E11B	CT11	120	20	2,544,690	1078.4
E12B	CT12	120	20	2,544,690	1078.4
E21B	CT21	120	20	2,544,690	1078.4
E22B	CT22	120	20	2,544,690	1078.4
E3	COOL1	46	36	6,998,916	88.0
E4	COOL2	46	36	6,998,916	88.0
E5	AB1	70	2.3	9,872	366.0
E6	AB2	70	2.3	9,872	366.0

Recommendation

The staff recommends to the Commissioner that the construction and operation be approved. This recommendation is based on the following facts and conditions:

Information, unless otherwise stated, used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this review was received on April 24, 2000, with additional information received on May 17, 2000, June 23, 2000, June 30, 2000, July 24, 2000, October 24, 2000, November 21, 2000, and December 4, 2000.

Emissions Calculation

See Appendix A (Emission Calculation Spreadsheets for detailed calculations (sixteen (16) pages)). Criteria pollutant emission rates from the turbines are based on General Electric vendor data or Supplement F of EPA AP-42 (4/00) emission factors from Chapter 3.1 (Stationary Gas Turbines for Electricity Generation) utilizing 100 percent natural gas. Criteria pollutant emission rates from the duct burners are based on vendor data or EPA AP-42 emission factors from Chapter 1.4 (Natural Gas Combustion from Boilers) utilizing 100 percent natural gas.

Emissions associated with startup/shutdown periods are higher than emissions associated with steady state operating conditions of the turbines. Therefore, calculations for the potential to emit (PTE) also include startup/shutdown emissions. The permit also contains separate conditions for periods of startup and shutdown.

Hazardous Air Pollutant (HAPs) emission calculations (with the exception of formaldehyde) are based on Supplement F of EPA AP-42 (4/00) emission factors from Chapter 3.1 (Stationary Gas Turbines for Electricity Generation). The HAP emission rates from the duct burners are based on EPA AP-42 emission factors from Chapter 1.4 (Natural Combustion from Boilers). An alternative emission factor for formaldehyde was submitted by source. The permit will require a formaldehyde stack test to verify the proposed formaldehyde emission factor.

Potential to Emit Emissions

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as “the maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, the department, or the appropriate local air pollution control agency."

The potential to emit has been separated into the following phases of constructions. Additionally, upon completion of Phase 3 of construction the facility will have the capability of both simple cycle operation and combined cycle operation. Therefore, Phase 3 potential emissions represent the worst case operating scenario.

(1) Phase 1 – four (4) natural gas combustion turbines operating in simple cycle mode including startup and shutdown emissions The following ancillary equipment is also included: two (2) emergency generators, and two (2) fire pumps.

(2) Phase 2 – two (2) natural gas combustion turbines operating in simple cycle mode including startup and shutdown emissions, two (2) natural gas combustion turbines operating in combined cycle mode including startup and shutdown emissions and duct burner firing. The following ancillary equipment is also included: one (1) auxiliary boiler, one (1) cooling tower, two (2) emergency generators, and two (2) fire pumps.

(3) Phase 3 – all four (4) natural gas combustion turbines operating in combined cycle mode including startup and shutdown emissions and duct firing. The following ancillary equipment is also included: two (2) cooling towers, two (2) emergency generators, and two (2) fire pumps.

The following tables represent the potential to emit for the three phases of construction:

Pollutant	Phase 1 PTE (tpy)	Phase 2 PTE (tpy)	Phase 3 PTE (tpy)	Permit Threshold Levels (tpy)
PM	315.28	342.30	367.04	25
PM_{10}	315.28	342.30	367.04	15
SO_2	74.90	77.62	80.16	40
VOC	67.47	81.44	93.75	40
CO	633.15	943.66	1228.90	100
NO_X	1102.24	1663.38	2209.50	40
Single HAP	9.4	10.35	11.29	10
Combination of HAPs	16.76	22.66	28.00	25

(a) Allowable emissions (as defined in the Indiana Rule) of NO_X, SO_2, PM, VOC and CO are greater than 25 tons per year. Therefore, pursuant to 326 IAC 2-1, Sections 1 and 3, a construction permit is required.

(b) Allowable emissions (as defined in the Indiana Rule) of a single hazardous air pollutant (HAP) are greater than 10 tons per year and/or the allowable emissions of any combination of the HAPs are greater than 25 tons per year. Therefore, pursuant to 326 IAC 2-1, a construction permit is required.

County Attainment Status

The source is located in Vigo County.

Pollutant	Status
PM_{10}	Attainment
SO_2	Attainment
NO_2	Attainment
Ozone	Attainment
CO	Attainment
Lead	Attainment

(a) Volatile organic compounds (VOC) and oxides of nitrogen (NO_X) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Vigo County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NO_X emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(b) Vigo County has been classified as attainment or unclassifiable for SO_2, PM, PM_{10} and CO. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

Source Status

New Source PSD Definition (emissions after controls, based on 8,760 hours of operation per year at rated capacity and/ or as otherwise limited including startup and shutdown emissions).

The source's emissions have been separated into the following phases of constructions. Additionally, upon completion of Phase 3 of construction the facility will have the capability of both simple cycle operation and combined cycle operation.

(1) Phase 1 – four (4) natural gas combustion turbines operating in simple cycle mode including startup and shutdown emissions. The following ancillary equipment is also included: two (2) emergency generators, and two (2) fire pumps.

(2) Phase 2 – two (2) natural gas combustion turbines operating in simple cycle mode including startup and shutdown emissions, two (2) natural gas combustion turbines operating in combined cycle mode, utilizing selective catalytic reduction (SCR) as control, including startup and shutdown emissions and duct burner firing limited to 1,314 hours per year. The following ancillary equipment is also included: one (1) auxiliary boiler limited to 5,000 hours per year, one (1) cooling tower, two (2) emergency generators, and two (2) fire pumps.

(3) Phase 3 – emissions represent the worst case emissions from any of the operating scenarios.

Pollutant	Phase 1 PTE (tpy)	Phase 2 PTE (tpy)	Phase 3 PTE (tpy)	Permit Threshold Levels (tpy)
PM	315.28	325.06	333.54	25
PM_{10}	315.28	325.06	333.54	15

SO_2	74.90	77.58	75.69	40
VOC	67.47	69.91	75.01	40
CO	633.15	755.06	862.56	100
NO_X	1102.24	855.42	1110.81	40
Single HAP	9.4	9.7	9.71	10
Combination of HAPs	16.76	17.77	18.45	25

(a) The NO_X emissions from the combustion turbine (when operating in combined cycle mode) and duct burner will be controlled by a selective catalytic reduction (SCR) system. Duct burners shall not be fired until turbines are brought to full load.

(b) The proposed combined cycle merchant power plant is a major stationary source because at least one regulated pollutant is emitted above its associated major source threshold level. Also the proposed facility is classified as a "fossil fuel-fired steam electric plant of more than 250 MMBtu per hour" and is, therefore, one of the 28 listed categories, as stated in 326 IAC 2-2.

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)

This new source is subject to the Part 70 Permit requirements because the potential to emit (PTE) of:

(a) at least one of the criteria pollutants is greater than or equal to 100 tons per year,

(b) a single hazardous air pollutant (HAP) is greater than or equal to 10 tons per year, or

(c) any combination of HAPs is greater than or equal to 25 tons/year.

This new source shall apply for a Part 70 (Title V) operating permit within twelve (12) months after this source becomes subject to Title V.

Acid Rain Permit Applicability [326 IAC 2-7-2]

This stationary source shall be required to have a Phase II, Acid Rain permit by 40 CFR 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CFR 72.6.

(b) The source cannot operate the combustion units until their Phase II, Acid Rain permit has been issued.

Federal Rule Applicability

40 CFR 60, Subpart GG (Stationary Gas Turbines)

The four (4) natural gas combustion turbines are subject to the New Source Performance Standard (NSPS) for Stationary Gas Turbines (40 CFR Part 60, Subpart GG) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions from the natural gas turbines to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

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

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

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

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight;

(3) Install a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine, as required by 40 CFR 60.334(a);

(a) Monitor the sulfur content and nitrogen content of the fuel being fired in the turbine, as required by 40 CFR 60.334(b); and

(5) Report periods of excess emissions, as required by 40 CFR 334(c).

40 CFR Part 60, Subpart Da (Electric Utility Steam Generating Units)

The proposed plant when operating in combined cycle is subject to the New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units (40 CFR 60 Subpart Da) because it is an electric utility steam generating facility that will be constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale.

According to 40 CFR 60.40a(b) (Applicability), only the four duct burners (300 MMBtu per hour, each), which constitute a portion of the electric utility steam generating unit, are subject to the requirements of this rule because they are capable of combusting more than 250 MMBtu per hour heat input of fossil fuel. Pursuant to the Federal Register dated May 25, 2000, duct burners are considered to be a steam generating unit. In addition, the Federal Register dated May 25, 2000 indicates that combustion turbines are not to be considered a steam generating unit and are therefore not subject to this subpart.

(a) Particulate matter emissions from each natural gas-fired duct burner shall not exceed 0.03 pounds per MMBtu heat input pursuant to 40 CFR 60.42a(a)(1). Opacity shall not exceed 20 percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent pursuant to 40 CFR 60.42a(b).

(b) Pursuant to 40 CFR 60.43a(b)(2) and 40 CFR 60.43a(g) (Sulfur Dioxide Standards), sulfur dioxide emissions from each natural gas-fired duct burner shall not exceed 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 0.20 pounds per MMBtu heat input, based on a 30-day rolling average.

(c) Pursuant to 40 CFR 60.44a(d)(2) (Nitrogen Oxide Standards), nitrogen oxide emissions from each natural gas-fired duct burner shall not exceed 1.6 pounds/MW-hr gross energy output on a 30-day rolling average.

(d) Pursuant to 40 CFR 60.46a (Compliance Provisions), the natural gas-fired duct burners are subject to the following requirements:

(1) The particulate matter emission standards and nitrogen oxide standards apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide standards apply at all times except during periods of startup or shutdown;

(2) After the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rate for 30 successive burner operating days. A separate performance test is completed at the end of each burner operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides; and

(3) For the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide and nitrogen oxide emission limitations are based on the average emission rates for the first 30 successive burner operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first burner operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but no later than 180 days after initial startup of the facility.

(e) Pursuant to 40 CFR 60.47a(a) and (b) (Emission Monitoring for Opacity and Sulfur Dioxide), the duct burners are not subject to the opacity and sulfur dioxide emission monitoring requirements because only natural gas fuel is combusted.

(f) Pursuant to 40 CFR 60.47a(c) (Emission Monitoring for Nitrogen Oxide), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere.

(g) Pursuant to 40 CFR 60.47(d) (Emission Monitoring for Oxygen or Carbon Dioxide), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen content of the flue gases at each location where sulfur dioxide or nitrogen oxide emissions are monitored.

(h) Pursuant to 40 CFR 60.48a (Compliance Determination Procedures), the Permittee shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures specified in this section. The Permittee shall determine compliance with the NOx standard as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NOx.

(2) The continuous monitoring system shall be used to determine the concentrations of NOx and O2.

(i) Pursuant to 40 CFR 60.49a (Reporting Requirements), the Permittee is subject to the following reporting requirements:

(1) NOx performance test data from the initial performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(2) Information required by 40 CFR 60.49a(b) from the NOx CEM for each 24-hour

period.

(3) Information required by 40 CFR 60.49a(c) when the minimum quantity of emission data is not obtained for any 30 successive burner operating days.

(4) For any periods for which nitrogen oxides emissions data are not available, the Permittee shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(5) Pursuant to 40 CFR 60.49a(g), the Permittee shall submit a signed statement indicating whether:

(A) The required CEM calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(B) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(C) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(D) Compliance with the standards has or has not been achieved during the reporting period.

(6) For the purposes of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under 40 CFR 42a(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are submitted to the Administrator each calendar quarter.

(7) The Permittee shall submit the written reports to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

40 CFR Part 60 Subpart Db (New Source Performance Standards for Industrial Steam Generating Units)

The proposed plant is not subject to the New Source Performance Standards (NSPS) for Industrial Steam Generating Units because the proposed plant is subject to the requirements of 40 CFR 60 Subpart Da. According to 40 CFR 60.40b(e) (Applicability Requirements), steam generating units meeting the applicability requirements of 40 CFR 60 Subpart Da are not subject to this subpart. Pursuant to the Federal Register date May 25, 2000, the combustion turbines are not considered to be a steam generating unit and are therefore not subject to this subpart

40 CFR Part 60 Subpart Dc (New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units)

Pursuant to New Source Performance Standards for Small Industrial Steam Generating Units any steam generating units that have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The proposed auxiliary boilers have a maximum rated heat input capacity of 35 MMBtu/hr and are, therefore, subject to the following requirements of

Subpart Dc:

(a) Notification include the following information:

(1) The design heat input capacity, and to identify the types of fuels to be combusted.

(2) The anticipated annual operating hours based on each individual fuel fired.

(b) The owner or operator record and maintain records of the amounts of each fuel combusted during each day. All records required shall be maintained for a period of two (2) years following the date of such record.

40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants)

There are no presently proposed or final National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations for electric utility steam generating units.

State Rule Applicability

326 IAC 1-5-2 and 326 IAC 1-5-3 (Emergency Reduction Plans)

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Management
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

within 180 days from the date on which this source commences operation.

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP. If after this time, the Permittee does not submit an approvable ERP, then IDEM, OAQ, shall supply such a plan.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAQ, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-3 (Implementation of ERP), the Permittee shall put into effect the actions stipulated in the approved ERP upon direct notification by OAQ that a specific air pollution episode is in effect.

326 IAC 1-6-3 (Preventive Maintenance)

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days of operation, including the following information on each:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission units;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions.

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that lack of proper maintenance does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMP's shall be submitted to IDEM and OAQ upon request and shall be subject to review and approval by IDEM and OAQ.

326 IAC 1-7 (Stack Height Provisions)

Stacks are subject to the requirements of 326 IAC 1-7 (Stack Height Provisions) because the potential emissions which exhaust through the above-mentioned stacks, are greater than 25 tons per year of PM and SO_2. This rule requires that the stack be constructed using Good Engineering Practice (GEP), unless field studies or other methods of modeling show to the satisfaction of IDEM that no excessive ground level concentrations, due to less than adequate stack height, will result.

The height of the proposed stack will be less than the GEP stack height. Therefore, a dispersion model to determine the significant ambient air impact area was developed and analysis of actual stack height with respect to GEP was performed. Appendix B discusses the results of this modeling exercise.

326 IAC 2-1-3.4 (New Source Toxics Rule)

The New Source Toxic Rule is not applicable because any single HAP emission is not greater than or equal to 10 tons per year per turbine and any combination HAP emissions are not greater than or equal to 25 tons per year per turbine.

326 IAC 2-2 (Prevention of Significant Deterioration)

This new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X because the potential to emit for these pollutants exceeds the PSD major "significant" thresholds, as specified in 326 IAC 2-2-1. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

The attached modeling analysis (Appendix B) was conducted to show that the major new source does not violate the NAAQS and does not exceed the incremental consumption above eighty percent (80%) of the PSD increment for any affected pollutant.

BACT for the facilities covered in this construction permit are determined on a case by case basis by reviewing similar process controls and new available technologies. In addition, economic, energy and environmental impacts are considered in IDEM's final decision. Control technology summaries of the facilities covered in this modification are included in Appendix C. The following tables represent a summary of the evaluated and approved BACT.

Simple Cycle Operation

Pollutant	Combustion Turbines	Limit (ppmvd @ 15% O_2)	Startup/Shutdown	Limit (ppmvd @ 15% O_2)
NO_X	Dry Low-NOx Combustors	9.0 (3 hour block avg.)	Limited to 2 hours per startup/shutdown and	80/48 (startup/shutdown)
CO	Good Combustor Design and Combustion Control	9 (24 hour avg.)	Limited to 2 hours per startup/shutdown and	150/90 (startup/shutdown)
VOC	Good Combustion Control	0.0025 lb/MMBtu	N/A	N/A
SO_2	Natural Gas as Sole Fuel	0.0028 lb/MMBtu	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.011 lb/MMBtu	N/A	N/A

lb/MMBtu limit for the combustion turbines is based on a lower heating value

Combined Cycle Operation

Pollutant	Combustion Turbines	Limit (ppmvd @ 15% O_2)	Combustion Turbines and Duct Burners	Limit (ppmvd @ 15% O_2)	Startup/Shutdown	Limit (ppmvd @ 15% O_2)
NO_X	Dry Low-NOx Combustors and SCR	3.0 (3 hour block avg.)	Dry Low-NOx Combustors and SCR	3.0 (3 hour block avg.)	Limited to 4 hours per startup/shutdown and Duct Burners not operated until normal operation begins	80/48 (startup/shut down)
CO	Good Combustor Design and Combustion Control	9 (24 hour avg.)	Good Combustor Design and Combustion Control	14 (24 hour avg.)	Limited to 4 hours per startup/shutdown and Duct Burners not operated until normal operation begins	150/90 (startup/shut down)
VOC	Good Combustion Control	0.0025 lb/MMBtu[1]	Good Combustion Control	5.3 lb/hr	N/A	N/A
SO_2	Natural Gas as Sole Fuel	0.0028 lb/MMBtu[1]	Natural Gas as Sole Fuel	4.4 lb/hr	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.011 lb/MMBtu[2]	Natural Gas as Sole Fuel and Good Combustion Practice	20.2 lb/hr	N/A	N/A

[1] lb/MMBtu limit for the combustion turbines is based on a lower heating value
[2] PM/PM_{10} limit also includes emissions associated with the use of SCR

Auxiliary Boiler and Cooling Tower Operation

Pollutant	Auxiliary Boiler	Limit (lb/MMBtu)	Cooling Tower	Limit
NO_X	Natural Gas as Sole Fuel and Low NOx Combustors	0.048	N/A	N/A
CO	Good Combustion Practice	0.083	N/A	N/A
VOC	Good Combustion Practice	0.0057	N/A	N/A
SO_2	Natural Gas as Sole Fuel	0.0029	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.008	Drift Eliminators	1.41 lb/hr

lb/MMBtu limit for the auxiliary boilers is based on a higher heating value

326 IAC 2-6 (Emission Reporting)

This source is subject to 326 IAC 2-6 (Emission Reporting), because the source will emit more than 100 tons/yr of NO_X and CO. Pursuant to this rule, the owner/operator of this source must annually submit an emission statement of the source. The annual statement must be received by July 1 of each year and must contain the minimum requirements as specified in 326 IAC 2-6-4.

326 IAC 3-5 (Continuous Monitoring of Emissions)

The proposed facility is subject to 326 IAC 3-5 (Continuous Monitoring of Emissions) because the unit is a fossil fuel-fired steam generator with a heat input capacity greater than 100 MMBtu per hour as defined by 326 IAC 3-5-1(b)(2).

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A)(i), and opacity monitor is not required because only gaseous fuel is combusted. The only fuel combusted at this source is natural gas.

(b) Pursuant to 326 IAC 3-5-1(c)(2)(B), an SO_2 continuous emission monitor (CEM) is not required because each steam generating unit is not equipped with an SO_2 control and 40 CFR 60 Subpart Db does not require an SO_2 monitor because only natural gas is combusted.

(c) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2 shall be required to install a continuous emission monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.

For NO_X and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous monitoring system for stacks designated as E11A, E12A, E21A, E22A, E11B, E12B, E21B, and E22B in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour and parts per million (ppmvd) at 15% O_2. The use of CEMS to measure and record the NO_X and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limit, the source shall take an average of the parts per million (ppmvd) corrected

to 15% O_2 over a three (3) hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppmvd) corrected to 15% O_2 over a twenty four (24) hour averaging period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7. The source shall also be required to maintain records of the amount of natural gas combusted per turbine on a monthly basis and the heat input capacity.

Compliance with this condition shall determine continuous compliance with the NO_X, CO and SO_2 emission limits established under the PSD BACT (326 IAC 2-2).

326 IAC 5-1-2 (Opacity Limitations)

Pursuant to 326 IAC 5-1-2 (Opacity Limitations) except as provided in 326 IAC 5-1-3 (Temporary Exemptions), the opacity shall meet the following:

(a) Opacity shall not exceed an average of 40% any one (1) six (6) minute averaging period.

(b) Opacity shall not exceed 60% for more than a cumulative total of 15 minutes (60 readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity monitor) in a 6-hour period.

326 IAC 6-2 (Particulate Emissions Limitations for Sources of Indirect Heating)

The proposed electric generation plant is not subject to the requirements of 326 IAC 6-2 because the combustion turbines are not utilized for indirect heating.

326 IAC 6-4 (Fugitive Dust Emission Limitations)

The proposed source is subject to the requirements of 326 IAC 6-4 because this rule applies to all sources of fugitive dust. Pursuant to the applicability requirements, “fugitive dust “ means the generation of particulate matter to the extent that some portion of the material escapes beyond the property line of boundaries of the property, right-of-way, or easement on which the source is located. The source shall be considered in violation of this rule if any of the criteria presented in 326 IAC 6-4-2 are violated.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)

The proposed source is subject to the requirements of 326 IAC 6-5 because the source is required to obtain a permit pursuant to 326 IAC 2. However, the OAQ shall exempt the source from the fugitive control plan pursuant to 326 IAC 6-5-3(b) because the proposed plant will not have material delivery of handling systems that would generate fugitive emissions and all of the roads and parking areas located at the proposed facility will be paved.

326 IAC 7-1 (Sulfur Dioxide Emission Limitations)

The proposed power plant is subject to the requirements of 326 IAC 7-1 because the plant is a fuel combustion facility and the SO_2 potential to emit is greater than 25 tons per year. Pursuant to 326 IAC 7-1.1-2, there are no specific emission limitations for the combustion of natural gas. Pursuant to 326 IAC 7-2-1, the Permittee shall submit natural gas reports of the calendar month average sulfur content, heat content, natural fuel consumption and sulfur dioxide emission rate in pounds per MMBtu, upon request of OAQ.

326 IAC 8-1-6 (New facilities; general reduction requirements)

Pursuant to 326 IAC 8-1-6 (New facilities; general reduction requirements), the requirements of BACT shall apply to each turbine because the potential to emit of VOC is greater than or equal to 25 tons per year per unit. Pursuant to 326 IAC 8-1-6, the source shall perform good combustion practices as BACT. The BACT chosen and approved for 326 IAC 2-2 (Prevention of Significant Deterioration) satisfies this 326 8-1-6 requirement.

326 IAC 8 (Volatile organic Compound Requirements)

The proposed power plant is not subject to any other state VOC requirements because there is not a source specific RACT for the proposed operation.

326 IAC 9 (Carbon Monoxide Emission Limits)

Pursuant to 326 IAC 9 (Carbon Monoxide Emission Limits), the source is subject to this rule because it is a stationary source which emits CO emissions and commenced operation after March 21, 1972. Under this rule, there is not a specific emission limit because the source is not an operation listed under 326 IAC 9-1-2.

326 IAC 10 (Nitrogen Oxides)

326 IAC 10 does not apply to the source because it is not located in the specified counties (Clark and Floyd) listed under 326 IAC 10-1-1.

Air Toxic Emissions

Indiana presently requests applicants to provide information on emissions of the 189 hazardous air pollutants set out in the Clean Air Act Amendments of 1990. These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industries. They are listed as air toxics on the Office of Air Management (OAQ) Construction Permit Application Form Y.

(a) This new source will emit levels of air toxics less than those which constitute a major source according to Section 112 of the 1990 Amendments to Clean Air Act.

(b) See attached spreadsheets for detailed air toxic calculations (pages 1-4).

Conclusion

The construction of this merchant power plant will be subject to the conditions of the attached proposed **Construction Permit No. CP-167-12208-00123.**

Appendix A: Emission Calculations

Company Name: Mirant
Address: 6500 Darwin Road, West Terre Haute, IN 47885
Construction Permit No.: 167-12208-00123
Permit Reviewer: David Howard

Summary

Potential to Emit

Phase 1					
	Simple (4)	SU/SD	Generator	Fire Pump	**TOTAL**
NOx	945.31	129.93	22.86	4.14	1102.24
CO	462.21	165.12	4.93	0.89	633.15
VOC	65.28	N/A	1.85	0.34	67.47
SO2	73.12	N/A	1.51	0.27	74.90
PM/PM10	313.36	N/A	1.62	0.29	315.28
Formaldehyde	9.40	N/A			9.40
Comb. HAP	16.76	N/A			16.76

Phase 2								
	Simple (2)	Combined (2)	SU/SD	Generator	Fire Pump	Boiler (1)	Cooling Tower (1)	**TOTAL**
NOx	472.66	961.46	194.75	22.86	4.14	7.51	N/A	1663.38
CO	231.11	446.60	247.50	4.93	0.89	12.63	N/A	943.66
VOC	32.64	45.78	N/A	1.85	0.34	0.83	N/A	81.44
SO2	36.56	39.19	N/A	1.51	0.27	0.09	N/A	77.62
PM/PM10	156.68	176.39	N/A	1.62	0.29	1.14	6.17	342.30
Formaldehyde	10.35		N/A			0.00	N/A	10.35
Comb. HAP	22.38		N/A			0.28	N/A	22.66

Phase 3 - All Simple Cycle						
	Simple (4)	SU/SD	Generator	Fire Pump	Boiler (2)	**TOTAL**
NOx	945.31	129.93	22.86	4.14	15.02	1117.26
CO	462.21	165.12	4.93	0.89	25.26	658.41
VOC	65.28	N/A	1.85	0.34	1.65	69.12
SO2	73.12	N/A	1.51	0.27	0.18	75.08
PM/PM10	313.36	N/A	1.62	0.29	2.28	317.56
Formaldehyde	9.40	N/A			0.54	9.94
Comb. HAP	16.76	N/A			0.57	17.33

or

Phase 3 - All Combined Cycle						
	Combined w/DBs (4)	SU/SD	Generator	Fire Pump	cooling tower	**Total**
NOx	1922.93	259.57	22.86	4.14	N/A	2209.50
CO	893.20	329.88	4.93	0.89	N/A	1228.90
VOC	91.56	N/A	1.85	0.34	N/A	93.75
SO2	78.37	N/A	1.51	0.27	N/A	80.16
PM/PM10	352.78	N/A	1.62	0.29	12.34	367.04
Formaldehyde	11.29	N/A			N/A	11.29
Comb. HAP	28.00	N/A			N/A	28.00

Limited Potential to Emit

Phase 1					
	Simple (4)	SU/SD	Generator	Fire Pump	**TOTAL**
NOx	945.31	129.93	22.86	4.14	1102.24
CO	462.21	165.12	4.93	0.89	633.15
VOC	65.28	N/A	1.85	0.34	67.47
SO2	73.12	N/A	1.51	0.27	74.90
PM/PM10	313.36	N/A	1.62	0.29	315.28
Formaldehyde	9.40	N/A			9.40
Comb. HAP	16.76	N/A			16.76

Phase 2								
	Simple (2)	Combined (2)	SU/SD	Generator	Fire Pump	Boiler (1)	Cooling Tower (1)	**TOTAL**
NOx	472.66	156.73	194.75	22.86	4.14	4.29	0	855.42
CO	231.11	263.43	247.50	4.93	0.89	7.21	0	755.06
VOC	32.64	34.61	N/A	1.85	0.34	0.47	0	69.91
SO2	36.56	39.19	N/A	1.51	0.27	0.05	0	77.58
PM/PM10	156.68	159.64	N/A	1.62	0.29	0.65	6.17	325.06
Formaldehyde	9.54		N/A			1.54E-01		9.70
Comb. HAP	17.61		N/A			1.62E-01		17.77

Phase 3 - All Simple Cycle						
	Simple (4)	SU/SD	Generator	Fire Pump	Boiler (2)	**TOTAL**
NOx	945.31	129.93	22.86	4.14	8.58	1110.81
CO	462.21	165.12	4.93	0.89	14.42	647.57
VOC	65.28	N/A	1.85	0.34	0.94	68.41
SO2	73.12	N/A	1.51	0.27	0.10	75.01
PM/PM10	313.36	N/A	1.62	0.29	1.30	316.58
Formaldehyde	9.40	N/A			0.31	9.71
Comb. HAP	16.76	N/A			0.32	17.09

Phase 3 - All Combined Cycle						
	Combined w/DBs (4)	SU/SD	Generator	Fire Pump	cooling tower	**Total**
NOx	313.45	259.57	22.86	4.14	0	600.02
CO	526.86	329.88	4.93	0.89	0	862.56
VOC	69.23	N/A	1.85	0.34	0	71.41
SO2	73.91	N/A	1.51	0.27	0	75.69
PM/PM10	319.28	N/A	1.62	0.29	12.34	333.54
Formaldehyde	9.68	N/A				9.68
Comb. HAP	18.45	N/A				18.45

Phase 1 - Simple Cycle Operation
Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 60 F **1490.50** MMBtu/hr Number of Turbines **4**

	Normal Operation	Startup/Shutdown
Hours per year of Operation	**8760**	**292**

Combustion Turbine									
Pollutant	Heat Input		Emission Factor		lb/hr	PTE/CT		Total PTE	
NO_X	1490.5	MMBtu/hr	0.0362	lb/MMBtu	53.96	236.33	tons/yr	945.31	tons/yr
CO	1490.5	MMBtu/hr	0.0177	lb/MMBtu	26.38	115.55	tons/yr	462.21	tons/yr
VOC	1490.5	MMBtu/hr	0.0025	lb/MMBtu	3.73	16.32	tons/yr	65.28	tons/yr
SO_2	1490.5	MMBtu/hr	0.0028	lb/MMBtu	4.17	18.28	tons/yr	73.12	tons/yr
PM_{10}	1490.5	MMBtu/hr	0.012	lb/MMBtu	17.89	78.34	tons/yr	313.36	tons/yr

Emission factors are vendor provided data
Calculations are based on 8468 hours per year of operation (Normal Opeartion + Startup/Shutdown = 8760 hrs/yr)

Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits

Combustion Turbine									
Pollutant	Heat Input		Emission Factor		lb/hr	PTE/CT		Total PTE	
NOx	1490.50	MMBtu/hr	0.0362	lb/MMbtu	53.96	236.33	tons/yr	945.31	tons/yr
CO	1490.50	MMBtu/hr	0.0177	lb/MMbtu	26.38	115.55	tons/yr	462.21	tons/yr
VOC	1490.50	MMBtu/hr	0.0025	lb/MMbtu	3.73	16.32	tons/yr	65.28	tons/yr
SO_2	1490.50	MMBtu/hr	0.0028	lb/MMbtu	4.17	18.28	tons/yr	73.12	tons/yr
PM_{10}	1490.50	MMBtu/hr	0.012	lb/MMbtu	17.89	78.34	tons/yr	313.36	tons/yr

Startup/Shutdown Emissions

Simple Cycle Operation

Estimated max hours of startup per year	250
Estimated max hours of shutdown per year	42

Emissions from Simple Cycle Operation (phase 1)				
Pollutant	Startup Emission Rate (lb/hr)	Shutdown Emission Rate (lb/hr)	Emission Rate/Turbine (tons/yr)	Total Emission Rate (tons/yr)
NO_X	236	142	32.48	129.93
CO	300	180	41.28	165.12

*Emission rate (lb/hr) includes both the startup and shutdown

Combustion Turbine Potential to Emit Calculations for HAPs

Pollutant	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/Turbine (tpy)	Total PTE (tpy)	Limited Total PTE (tpy)
Benzene	1.20E-05	0.0179	0.078	0.313	0.313
Formaldehyde*	3.60E-04	0.5366	2.350	9.401	9.401
Xylenes	6.40E-05	0.0954	0.418	1.671	1.671
Ethylbenzene	3.20E-05	0.0477	0.209	0.836	0.836
1,3 Butadiene	4.30E-07	0.0006	0.003	0.011	0.011
Napthalene	1.30E-06	0.0019	0.008	0.034	0.034
Toluene	1.30E-04	0.1938	0.849	3.395	3.395
PAH	2.20E-06	0.0033	0.014	0.057	0.057
Acetaldehyde	4.00E-05	0.0596	0.261	1.045	1.045
			single HAP	9.40	9.40
			combined HAP	16.76	16.76

HAPs emission factor are from AP-42 Table 3.1-3

*Formaldehyde Emission factor is vendor provided data

Phase 2 - 1/2 Simple Cycle and 1/2 Combined Cycle

Combustion Turbine and Duct Burner Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

				Simple	**Combined**
Combustion Turbine Heat input @ 60 F	**1490.5**	MMBtu/hr	Number of Turbines	**2**	**2**
Duct Burner Heat input @ 60 F	**300**	MMBtu/hr	Number of Duct Burners	**0**	**2**

	Normal Operation		Startup/Shutdown	
	Simple	Combined	Simple	Combined
Turbine Operation (hrs/yr)	**8760**	**8760**	**292**	**583**
Duct Burner Operation (hrs/yr)	**0**	**1314**		

Simple Cycle Combustion Turbine

Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NOx	1490.5 MMBtu/hr	0.0362 lb/MMBtu	53.96	236.33 tpy	472.66 tpy
CO	1490.5 MMBtu/hr	0.0177 lb/MMBtu	26.38	115.55 tpy	231.11 tpy
VOC	1490.5 MMBtu/hr	0.0025 lb/MMBtu	3.73	16.32 tpy	32.64 tpy
SO2	1490.5 MMBtu/hr	0.0028 lb/MMBtu	4.17	18.28 tpy	36.56 tpy
PM10	1490.5 MMBtu/hr	0.012 lb/MMBtu	17.89	78.34 tpy	156.68 tpy

Combined Cycle Combustion Turbine

Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NOx	1490.5 MMBtu/hr	0.0362 lb/MMBtu	53.96	236.33 tpy	472.66 tpy
CO	1490.5 MMBtu/hr	0.0177 lb/MMBtu	26.38	115.55 tpy	231.11 tpy
VOC	1490.5 MMBtu/hr	0.0025 lb/MMBtu	3.73	16.32 tpy	32.64 tpy
SO2	1490.5 MMBtu/hr	0.0028 lb/MMBtu	4.17	18.28 tpy	36.56 tpy
PM10	1490.5 MMBtu/hr	0.012 lb/MMBtu	17.89	78.34 tpy	156.68 tpy

Duct Burner

Pollutant	Heat Input	Emission Factor	lb/hr	PTE/DB	Total PTE
NOx	300 MMBtu/hr	0.186 lb/MMBtu	55.8	244.40 tpy	488.81 tpy
CO	300 MMBtu/hr	0.082 lb/MMBtu	24.6	107.75 tpy	215.50 tpy
VOC	300 MMBtu/hr	0.005 lb/MMBtu	1.5	6.57 tpy	13.14 tpy
SO2	300 MMBtu/hr	0.001 lb/MMBtu	0.3	1.31 tpy	2.63 tpy
PM10	300 MMBtu/hr	0.0075 lb/MMBtu	2.25	9.86 tpy	19.71 tpy

Combustion turbine emission factors are vendor provide data

Duct burner emission factors are from AP-42, Chapter 1.4

Calculations are based on 8468 (SC) and 8177 (CC) hours per year of operation (Normal Opeartion + Startup/Shutdown = 8760 hrs/yr)

Duct Burner PTE is based on 8760 hrs/yr operation

Combustion Turbine and Duct Burner PTE

Pollutant	Simple Cycle PTE/Single Unit	Combined Cycle PTE/Single Unit	Total Simple Cycle PTE	Total Combined Cycle PTE	Total
NO_X	236.33 tpy	480.73 tpy	472.66 tpy	961.46 tpy	1434.12
CO	115.55 tpy	223.30 tpy	231.11 tpy	446.60 tpy	677.71
VOC	16.32 tpy	22.89 tpy	32.64 tpy	45.78 tpy	78.42
SO_2	18.28 tpy	19.59 tpy	36.56 tpy	39.19 tpy	75.75
PM_{10}	78.34 tpy	88.20 tpy	156.68 tpy	176.39 tpy	333.07

Combustion Turbine and Duct Burner Potential to Emist Calculations - After Controls or Federally Enforcable Limits

Simple Cycle Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NOx	1490.5 MMBtu/hr	0.0362 lb/MMBtu	53.96	236.33 tpy	472.66 tpy
CO	1490.5 MMBtu/hr	0.0177 lb/MMBtu	26.38	115.55 tpy	231.11 tpy
VOC	1490.5 MMBtu/hr	0.0025 lb/MMBtu	3.73	16.32 tpy	32.64 tpy
SO2	1490.5 MMBtu/hr	0.0028 lb/MMBtu	4.17	18.28 tpy	36.56 tpy
PM10	1490.5 MMBtu/hr	0.012 lb/MMBtu	17.89	78.34 tpy	156.68 tpy

Combined Cycle Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NOx	1490.5 MMBtu/hr	0.012 lb/MMBtu*	17.89	78.34 tpy	156.68 tpy
CO	1490.5 MMBtu/hr	0.0177 lb/MMBtu	26.38	115.55 tpy	231.11 tpy
VOC	1490.5 MMBtu/hr	0.0025 lb/MMBtu	3.73	16.32 tpy	32.64 tpy
SO2	1490.5 MMBtu/hr	0.0028 lb/MMBtu	4.17	18.28 tpy	36.56 tpy
PM10	1490.5 MMBtu/hr	0.012 lb/MMBtu	17.89	78.34 tpy	156.68 tpy

Duct Burner					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NOx	300 MMBtu/hr	1.13E-04 lb/MMBtu*	0.034	0.02 tpy	0.04 tpy
CO	300 MMBtu/hr	0.082 lb/MMBtu	24.6	16.16 tpy	32.32 tpy
VOC	300 MMBtu/hr	0.005 lb/MMBtu	1.5	0.99 tpy	1.97 tpy
SO2	300 MMBtu/hr	0.001 lb/MMBtu	0.3	0.20 tpy	0.39 tpy
PM10	300 MMBtu/hr	0.0075 lb/MMBtu	2.25	1.48 tpy	2.96 tpy

*NOx emission factor for combustion turbine and duct burner is based on control with SCR to 3.0 ppm

Duct burner limited PTE reflects a limit of 1,314 hrs/yr of operation

Duct burner emission factors are from AP-42, Chapter 1.4

Limited PTE for Combustion Turbines and Duct Burners					
Pollutant	Simple Cycle PTE/Single Unit	Combined Cycle PTE/Single Unit	Total Simple Cycle PTE	Total Combined Cycle PTE	Total
NOx	236.33 tpy	78.36 tpy	472.66 tpy	156.73 tpy	629.38
CO	115.55 tpy	131.71 tpy	231.11 tpy	263.43 tpy	494.53
VOC	16.32 tpy	17.31 tpy	32.64 tpy	34.61 tpy	67.25
SO2	18.28 tpy	18.48 tpy	36.56 tpy	36.95 tpy	73.51
PM10	78.34 tpy	79.82 tpy	156.68 tpy	159.64 tpy	316.32

Startup/Shutdown Emissions

Combined Cycle Operation

Estimated max hours of startup per year	**500**
Estimated max hours of shutdown per year	**83**

Emissions from Combined Cycle Opeartion				
Pollutant	Startup Emission Rate (lb/hr)	Shutdown Emission Rate (lb/hr)	Emission Rate/Turbine (tons/yr)	Total Emission Rate (tons/yr)
NO_X	236	142	64.89	129.79
CO	300	180	82.47	164.94

*Emission rate (lb/hr) includes both the startup and shutdown

Simple Cycle Operation

Estimated max hours of startup per year	250
Estimated max hours of shutdown per year	42

Emissions from Simple Cycle Operation				
Pollutant	Startup Emission Rate (lb/hr)	Shutdown Emission Rate (lb/hr)	Emission Rate/Turbine (tons/yr)	Total Emission Rate (tons/yr)
NO_X	236	142	32.482	64.96
CO	300	180	41.28	82.56

*Emission rate (lb/hr) includes both the startup and shutdown

Total for 2 Simple Cycle and 2 Combined Cycle	
Pollutant	Total
NO_X	194.75
CO	247.50

HAPs Emission for Combined Cycle Operation

	Duct Burner				Combustion Turbine				Project Total CTs + DBs	
HAPs	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @ 1314 hrs/yr	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @ 8760 hrs/yr	tons/yr before control	tons/yr after control
Benzene	2.06E-06	6.18E-04	2.71E-03	4.06E-04	1.20E-05	1.79E-02	7.83E-02	7.8E-02	3.19E-01	3.14E-01
Dichlorobenzene	1.18E-06	3.53E-04	1.55E-03	2.32E-04					3.09E-03	4.64E-04
Formaldehyde*	3.60E-04	1.08E-01	4.73E-01	7.10E-02	3.60E-04	5.37E-01	2.35E+00	2.4E+00	1.03E+01	9.54E+00
Xylenes					6.40E-05	9.54E-02	4.18E-01	4.2E-01	1.67E+00	1.67E+00
Hexane	1.76E-03	5.29E-01	2.32E+00	3.48E-01					4.64E+00	6.96E-01
Ethylbenzene					3.20E-05	4.77E-02	2.09E-01	2.1E-01	8.36E-01	8.36E-01
1,3 Butadiene					4.30E-07	6.41E-04	2.81E-03	2.8E-03	1.12E-02	1.12E-02
Napthalene	5.98E-07	1.79E-04	7.86E-04	1.18E-04	1.30E-06	1.94E-03	8.49E-03	8.5E-03	3.55E-02	3.42E-02
Toluene	3.33E-06	1.00E-03	4.38E-03	6.57E-04	1.30E-04	1.94E-01	8.49E-01	8.5E-01	3.40E+00	3.40E+00
PAH					2.20E-06	3.28E-03	1.44E-02	1.4E-02	5.74E-02	5.74E-02
POM	8.65E-08	2.59E-05	1.14E-04	1.70E-05					2.27E-04	3.41E-05
Acetaldehyde					4.00E-05	5.96E-02	2.61E-01	2.6E-01	1.04E+00	1.04E+00
Arsenic	1.96E-07	5.88E-05	2.58E-04	3.86E-05					5.15E-04	7.73E-05
Beryllium	1.18E-08	3.53E-06	1.55E-05	2.32E-06					3.09E-05	4.64E-06
Cadmium	1.08E-06	3.24E-04	1.42E-03	2.13E-04					2.83E-03	4.25E-04
Chromium	1.37E-06	4.12E-04	1.80E-03	2.71E-04					3.61E-03	5.41E-04
Cobalt	8.24E-08	2.47E-05	1.08E-04	1.62E-05					2.16E-04	3.25E-05
Manganese	3.73E-07	1.12E-04	4.90E-04	7.34E-05					9.79E-04	1.47E-04
Mercury	2.55E-07	7.65E-05	3.35E-04	5.02E-05					6.70E-04	1.00E-04
Nickel	2.06E-06	6.18E-04	2.71E-03	4.06E-04					5.41E-03	8.12E-04
Selenium	2.35E-08	7.06E-06	3.09E-05	4.64E-06					6.18E-05	9.28E-06
							single HAP		10.35	9.54
							combined HAP		22.38	17.61

HAPs emission factors for the turbines are from AP-42 Table 3.1-3

HAPs emission factors for the duct burners are from AP-42 Table 1.4-3

*Formaldehyde emission factor is vendor provide data

Phase 3 - Combined Cycle

Combustion Turbine and Duct Burner Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 60 F	**1490.50**	MMBtu/hr	Number of Turbines	**4**
Duct Burner Heat input @ 60 F	**300**	MMBtu/hr	Number of Duct Burners	**4**

	Normal Operation	Startup/Shutdown
Turbine Operation (hrs/yr)	**8760**	**583**
Duct Burner Operation (hrs/yr)	**1314**	

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1490.5 MMBtu/hr	0.0362 lb/MMBtu	53.96	236.33 tons/yr	945.31 tons/yr
CO	1490.5 MMBtu/hr	0.0177 lb/MMBtu	26.38	115.55 tons/yr	462.21 tons/yr
VOC	1490.5 MMBtu/hr	0.0025 lb/MMBtu	3.73	16.32 tons/yr	65.28 tons/yr
SO_2	1490.5 MMBtu/hr	0.0028 lb/MMBtu	4.17	18.28 tons/yr	73.12 tons/yr
PM_{10}	1490.5 MMBtu/hr	0.012 lb/MMBtu	17.89	78.34 tons/yr	313.36 tons/yr

Duct Burner					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/DB	Total PTE
NO_X	300 MMBtu/hr	0.186 lb/MMBtu	55.8	244.40 tons/yr	977.62 tons/yr
CO	300 MMBtu/hr	0.082 lb/MMBtu	24.6	107.75 tons/yr	430.99 tons/yr
VOC	300 MMBtu/hr	0.005 lb/MMBtu	1.5	6.57 tons/yr	26.28 tons/yr
SO_2	300 MMBtu/hr	0.001 lb/MMBtu	0.3	1.31 tons/yr	5.26 tons/yr
PM_{10}	300 MMBtu/hr	0.0075 lb/MMBtu	2.25	9.86 tons/yr	39.42 tons/yr

Combustion turbine emission factors are vendor provide data

Duct burner emission factors are from AP-42, Chapter 1.4

Calculations are based on 8177 (CC) hours per year of operation (Normal Opeartion + Startup/Shutdown = 8760 hrs/yr)

Duct Burner PTE is based on 8760 hrs/yr operation

Combustion Turbine and Duct Burner PTE			
Pollutant	lb/hr	PTE/Single Unit	Total PTE
NO_X	109.76	480.73 tons/yr	1922.93 tons/yr
CO	50.98	223.30 tons/yr	893.20 tons/yr
VOC	5.23	22.89 tons/yr	91.56 tons/yr
SO_2	4.47	19.59 tons/yr	78.37 tons/yr
PM_{10}	20.14	88.20 tons/yr	352.78 tons/yr

Combustion Turbine and Duct Burner Potential to Emit Calculation - After Control or Federally Enforceable Limits

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1490.5 MMBtu/hr	0.012 lb/MMBtu*	17.89	78.34 tons/yr	313.36 tons/yr
CO	1490.5 MMBtu/hr	0.0177 lb/MMBtu	26.38	115.55 tons/yr	462.21 tons/yr
VOC	1490.5 MMBtu/hr	0.0025 lb/MMBtu	3.73	16.32 tons/yr	65.28 tons/yr
SO_2	1490.5 MMBtu/hr	0.0028 lb/MMBtu	4.17	18.28 tons/yr	73.12 tons/yr
PM_{10}	1490.5 MMBtu/hr	0.012 lb/MMBtu	17.89	78.34 tons/yr	313.36 tons/yr

Duct Burner					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	300 MMBtu/hr	1.13E-04 lb/MMBtu*	0.034	0.02 tons/yr	0.09 tons/yr
CO	300 MMBtu/hr	0.082 lb/MMBtu	24.6	16.16 tons/yr	64.65 tons/yr
VOC	300 MMBtu/hr	0.005 lb/MMBtu	1.5	0.99 tons/yr	3.94 tons/yr
SO_2	300 MMBtu/hr	0.001 lb/MMBtu	0.3	0.20 tons/yr	0.79 tons/yr
PM_{10}	300 MMBtu/hr	0.0075 lb/MMBtu	2.25	1.48 tons/yr	5.91 tons/yr

*NOx emission factor for combustion turbine and duct burner is based on control with SCR to 3.0 ppm

Duct burner limited PTE reflects a limit of 1,314 hrs/yr of operation

Duct burner emission factors are from AP-42, Chapter 1.4

Combustion Turbine and Duct Burner Limited PTE			
Pollutant	lb/hr	Limited PTE/Single Unit	Total Limited PTE
NO_X	17.92	78.36 tons/yr	313.45 tons/yr
CO	50.98	131.71 tons/yr	526.86 tons/yr
VOC	5.23	17.31 tons/yr	69.23 tons/yr
SO_2	4.47	18.48 tons/yr	73.91 tons/yr
PM_{10}	20.14	79.82 tons/yr	319.28 tons/yr

Startup/Shutdown Emissions

Combined Cycle Operation

Estimated max hours of startup per year	**500**
Estimated max hours of shutdown per year	**83**

Emissions from Combined Cycle Opeartion (phase 3)				
Pollutant	Startup Emission Rate (lb/hr)	Shutdown Emission Rate (lb/hr)	Emission Rate/Turbine (tons/yr)	Total Emission Rate (tons/yr)
NO_X	236	142	64.89	259.57
CO	300	180	82.47	329.88

*Emission rate/Turbine (tpy) includes both the startup and shutdown

Combustion Turbine and Duct Burner Potential to Emit Calculations for HAPs

	Duct Burner				Combustion Turbine				Project Total CTs + DBs	
HAPs	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @1314 hrs/yr	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr)	ton/yr @ 8760 hrs/yr	tons/yr before control	tons/yr after control
Benzene	2.06E-06	6.18E-04	2.71E-03	4.06E-04	1.20E-05	1.79E-02	7.83E-02	7.83E-02	3.24E-01	3.15E-01
Dichlorobenzene	1.18E-06	3.53E-04	1.55E-03	2.32E-04					6.18E-03	9.28E-04
Formaldehyde*	3.60E-04	1.08E-01	4.73E-01	7.10E-02	3.60E-04	5.37E-01	2.35E+00	2.35E+00	1.13E+01	9.68E+00
Xylenes					6.40E-05	9.54E-02	4.18E-01	4.18E-01	1.67E+00	1.67E+00
Hexane	1.76E-03	5.29E-01	2.32E+00	3.48E-01					9.28E+00	1.39E+00
Ethylbenzene					3.20E-05	4.77E-02	2.09E-01	2.09E-01	8.36E-01	8.36E-01
1,3 Butadiene					4.30E-07	6.41E-04	2.81E-03	2.81E-03	1.12E-02	1.12E-02
Napthalene	5.98E-07	1.79E-04	7.86E-04	1.18E-04	1.30E-06	1.94E-03	8.49E-03	8.49E-03	3.71E-02	3.44E-02
Toluene	3.33E-06	1.00E-03	4.38E-03	6.57E-04	1.30E-04	1.94E-01	8.49E-01	8.49E-01	3.41E+00	3.40E+00
PAH					2.20E-06	3.28E-03	1.44E-02	1.44E-02	5.74E-02	5.74E-02
POM	8.65E-08	2.59E-05	1.14E-04	1.70E-05					4.54E-04	6.82E-05
Acetaldehyde					4.00E-05	5.96E-02	2.61E-01	2.61E-01	1.04E+00	1.04E+00
Arsenic	1.96E-07	5.88E-05	2.58E-04	3.86E-05					1.03E-03	1.55E-04
Beryllium	1.18E-08	3.53E-06	1.55E-05	2.32E-06					6.18E-05	9.28E-06
Cadmium	1.08E-06	3.24E-04	1.42E-03	2.13E-04					5.67E-03	8.50E-04
Chromium	1.37E-06	4.12E-04	1.80E-03	2.71E-04					7.21E-03	1.08E-03
Cobalt	8.24E-08	2.47E-05	1.08E-04	1.62E-05					4.33E-04	6.49E-05
Manganese	3.73E-07	1.12E-04	4.90E-04	7.34E-05					1.96E-03	2.94E-04
Mercury	2.55E-07	7.65E-05	3.35E-04	5.02E-05					1.34E-03	2.01E-04
Nickel	2.06E-06	6.18E-04	2.71E-03	4.06E-04					1.08E-02	1.62E-03
Selenium	2.35E-08	7.06E-06	3.09E-05	4.64E-06					1.24E-04	1.86E-05

	tons/yr before control	tons/yr after control
single HAP	11.29	9.68
combined HAP	28.00	18.45

Natural Gas Utility Boiler Calculation

Auxiliary Boiler Heat Input Rate 35 MMBtu/hr

Number of Boilers 2

Boiler Operation (hrs/yr) 5000

Auxiliary Boiler									
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE (x2)		PTE after Control or Enforcable Limits	
NO_X	35	MMBtu/hr	4.90E-02	lb/MMBtu*	1.715	15.02	ton/yr	8.58	ton/yr
CO	35	MMBtu/hr	8.24E-02	lb/MMBtu	2.884	25.26	ton/yr	14.42	ton/yr
VOC	35	MMBtu/hr	5.39E-03	lb/MMBtu	0.189	1.65	ton/yr	0.94	ton/yr
SO_2	35	MMBtu/hr	5.88E-04	lb/MMBtu	0.021	0.18	ton/yr	0.10	ton/yr
PM_{10}	35	MMBtu/hr	7.45E-03	lb/MMBtu	0.261	2.28	ton/yr	1.30	ton/yr

Emission Factors from AP-42: Table 1.4-1and 1.4-2

*NOx emission is based on Low NOx burner emission factor

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/Boiler Before Control (tpy)	Total PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.06E-06	7.21E-05	3.16E-04	3.60E-04
Diclorobenzene	1.20E-03	1.18E-06	4.12E-05	1.80E-04	2.06E-04
Formaldehyde	7.50E-02	7.35E-05	2.57E-03	1.13E-02	1.29E-02
Hexane	1.80E+00	1.76E-03	6.18E-02	2.71E-01	3.09E-01
Napthalene	6.10E-04	5.98E-07	2.09E-05	9.17E-05	1.05E-04
Toluene	3.40E-03	3.33E-06	1.17E-04	5.11E-04	5.83E-04
POM	8.87E-05	8.70E-08	3.04E-06	1.33E-05	1.52E-05
Arsenic	2.00E-04	1.96E-07	6.86E-06	3.01E-05	3.43E-05
Beryllium	1.20E-05	1.18E-08	4.12E-07	1.80E-06	2.06E-06
Cadmium	1.10E-03	1.08E-06	3.77E-05	1.65E-04	1.89E-04
Chromium	1.40E-03	1.37E-06	4.80E-05	2.10E-04	2.40E-04
Cobalt	8.40E-05	8.24E-08	2.88E-06	1.26E-05	1.44E-05
Manganese	3.80E-04	3.73E-07	1.30E-05	5.71E-05	6.52E-05
Mercury	2.60E-04	2.55E-07	8.92E-06	3.91E-05	4.46E-05
Nickel	2.10E-03	2.06E-06	7.21E-05	3.16E-04	3.60E-04
Selenium	2.40E-05	2.35E-08	8.24E-07	3.61E-06	4.12E-06
		Single HAP		2.71E-01	3.09E-01
		Combined HAP		2.84E-01	3.24E-01

HAPs emission factors based on AP-42 1.4-3

Cooling Tower Emissions

	Value	Unit	Calculation
Flow of Water at 100% Load	128000	gpm	vendor information
Cooling Water Flowrate	64051200	lb/hr	Flowrate (gal/min) * 8.34 lb/gal * 60 min/hr
Total Disolved Solids (TDS)	2200	ppm	vendor information
Cooling Water TDS Fraction	0.0022	lb TDS/lb	TDS/10^6 lb/ppm
Drift Loses (% of cooling water)	0.001	%	vendor information
Liquid Drift Losses	640.512	lb/hr	Cooling water flow rate lb/hr * 0.001/100
Solids Drift Losses	1.409	lb/hr	Liquid Drift Losses * TDS Fraction lb TDS/lb
PM_{10}/TSD Emission	6.172	ton/yr	

PM_{10}/TSP Emissions for two cooling towers **12.344** ton/yr

Emission Calculations for Emergency Generator and Fire Pump

Emergency Generator	1475	hp	Number of Emergency Generators	2	
Fire Pump	267	hp	Number of Fire Pumps	2	

Emergency Generator Operation	500	hrs/yr
Fire Pump Operation	500	hrs/yr

Emergency Generator				
Pollutant	Emission Factor (lb/hp-hr)	lb/hr	PTE/unit (tpy)	Total PTE (tpy)
NO_X	0.031	45.73	11.43	22.86
CO	6.68E-03	9.85	2.46	4.93
VOC	2.51E-03	3.70	0.93	1.85
SO_2	2.05E-03	3.02	0.76	1.51
PM_{10}	2.20E-03	3.25	0.81	1.62

Fire Pump				
Pollutant	Emission Factor (lb/hp-hr)	lb/hr	PTE/unit (tpy)	Total PTE (tpy)
NO_X	0.031	8.28	2.07	4.14
CO	6.68E-03	1.78	0.45	0.89
VOC	2.51E-03	0.67	0.17	0.34
SO_2	2.05E-03	0.55	0.14	0.27
PM_{10}	2.20E-03	0.59	0.15	0.29

Emission factors for emergency generator are based on AP-42 Table 3.4-1 Uncontrolled
Emission factors for fire pump are based on AP-42 Table 3.3-1 Uncontrolled
PTE is based on a maximum 500 hours per year operation

Appendix B - Air Quality Analysis

Source Name:	Mirant Sugar Creek LLC
Source Location:	6500 Darwin Road, West Terre Haute, IN 47885
County:	Vigo
Construction Permit No.:	CP-167-12208-00123
SIC Code:	4911

Introduction

Mirant Sugar Creek, LLC (Mirant) has applied for a Prevention of Significant Deterioration (PSD) Permit to construct a combined cycle merchant facility in Vigo County, Indiana. The proposed site will be located in Terre Haute at Universal Transverse Mercator (UTM) coordinates 456079 East and 4360205 North. The proposed electric generation facility will have a plant output rate of approximately 1008 megawatts (MW). The plant will incorporate four combustion turbines (CTs), four duct burners (DBs), four heat recovery steam generators (HRSGs), two auxiliary boilers, and two steam turbines (STs). Vigo County is designated attainment for all criteria pollutants. All air quality modeling and analysis treats the proposed electric generation facility as a new major source.

Trinity Consultants (Trinity) prepared the permit application for Mirant. The permit application was received by the Office of Air Quality (OAQ) on April 21, 2000 and May 17, 2000. Modeling revisions to the application were received on February 2, 2001. This document provides the review of the modeling section of the permit application and an air quality analysis performed by OAQ.

Air Quality Impact Objectives

The purpose of the air quality impact analysis in the permit application is to accomplish the following objectives. Each objective is individually addressed in this document in each section outlined below.

A. Establish which pollutants require an air quality analysis based on PSD significant emission rates.

B. Provide analyses of actual stack heights with respect to Good Engineering Practice (GEP), the meteorological data used, a description of the model used in the analysis, and the receptor grid utilized for the analyses.

C. Determine the significant impact level, the area of the source's emissions and background air quality levels.

D. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or PSD increment if the applicant exceeds significant impact levels.

E. Perform an analysis of any air toxic compound with a health risk factor on the general population.

F. Perform a qualitative analysis of the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park, which is more than 100 kilometers from the proposed site in Vigo County, Indiana.

G. Summarize the Air Quality Analysis

Analysis Summary

The air quality impact analysis determined that no refined modeling would be required since pollutant concentrations did not exceed significant impact levels. The Reactive Plume Model–IV (RPM-IV) results showed no significant impact to ozone formation. Hazardous Air Pollutant (HAP) concentrations were all below .5% of the Permissible Exposure Limit (PEL). Based on these modeling results, the proposed Mirant Sugar Creek Plant will not have a significant impact to air quality.

Section A

Pollutants Analyzed for Air Quality Impact

The PSD requirements, 326 IAC 2-2, apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1. Particulate Matter less than 10 microns (PM_{10}), Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO_2), Volatile Organic Compounds (VOC)(an Ozone (O_3) precursor), and Carbon Monoxide (CO), are the pollutants that will be emitted from the electric generation facility. Therefore, an air quality analysis is required for these pollutants which exceeded their significant emission rates as shown in Table 1:

TABLE 1
Significant Emission Rates for PSD

POLLUTANT	SOURCE EMISSION RATE[1] (Facility Totals)	SIGNIFICANT EMISSION RATE	PRELIMINARY AQ ANALYSIS REQUIRED
	(tons/year)	(tons/year)	
PM_{10}	334.9	15.0	Yes
NO_2	324.1	40.0	Yes
VOCs (O_3)	70	40.0	Yes
CO	541.9	100.0	Yes
SO_2	74.2	40	Yes

[1]Taken from Table 1-1 of Volume III of application.

Section B

Stack Height Compliance with Good Engineering Practice (GEP)

Stacks should comply with GEP requirements established in 326 IAC 1-7-1. If stacks are lower than GEP, excessive ambient concentrations due to aero-dynamic downwash may occur. Stacks taller than 65 meters (213 feet) are limited to GEP, the stack height for establishing emission limitations. The GEP stack height takes into account the distance and dimensions of nearby structures, which would affect the downwind wake of the stack. The downwind wake is considered to extend five times the lesser of the structure's height or width. A GEP stack height is determined for each nearby structure by the following formula:

$$Hg = H + 1.5L$$

Where: Hg is the GEP stack height

H is the structure height
L is the structure's lesser dimension (height or width)

Since the stack heights of the proposed facility were below GEP stack height the effect of aerodynamic downwash will be accounted for in the air quality analysis for the proposed electric cogeneration facility.

Meteorological Data

The meteorological data used in the Industrial Source Complex Short Term (ISCST3) model consisted of 1990 through 1994 surface data from the Indianapolis International Airport Weather Service station merged with the mixing heights from Peoria, Illinois Airport National Weather Service station. The meteorological data was purchased through the National Oceanic and Atmospheric Administration (NOAA) and National Climatic Data Center (NCDC) and preprocessed into ISCST3 ready format using U.S.EPA's PCRAMMET.

Model Description

The OAQ used the ISCST3 model, version 00101 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the U.S. EPA approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W "Guideline on Air Quality Models". The Auer Land Use Classification Scheme was used to determine the land use in the area. The area is considered primarily rural; therefore, a rural classification was used.

Receptor Grid

OAQ modeling utilized the same receptor grids generated by Trinity Consultants, which extended out to 10 kilometers from the fence line. Five Cartesian receptor grids were utilized and are defined as follows: 1) a "fence line" grid consisting of evenly-spaced receptors 100 meters apart placed along the proposed facility fence line, 2) a "tight" grid containing 100-meter spaced receptors extending approximately 2.0 km from the fence line exclusive of the receptors within the proposed facility fence line, 3) a "fine grid" containing 200-meter spaced receptors extending 4 km from the fence line exclusive of receptors on the tight grid, and 4) a "medium grid" containing 500-meter spaced receptors extending 10 km from the fence line exclusive of receptors on the fine grid.

<u>Section C</u>

Significant Impact Level/Significant Impact Area (SIA) and Background Air Quality Levels

Trinity and Mirant determined two worst case operating scenarios for modeling. Table 2 summarizes the two scenarios.

TABLE 2
<u>Operating Scenarios</u>

Modeling Scenario	Units Operating	Operating Parameters
Scenario #1 – Worst Case Simple Cycle Operation with Auxiliary	• All four CT's operating/and exhausting through bypass stacks.	• Bypass stacks are located prior to control equipment.

Boilers	• Both auxiliary boilers operating and exhausting through boiler stacks. • Both cooling towers operating.	• Emissions modeled are based on uncontrolled vendor data for the CTs operating at 100% load for 8,760 hr/yr. • Emissions from the cooling towers are based on operating at 100% load for 8,760 hr/yr. • Emissions from the auxiliary boilers are based on 100% load operating 5,000 hr/yr. • US EPA's ARM ratio method is used to determine NO2 impacts
Scenario #2 Worst-Case Combined Cycle Operation	• All four CT's operating in power augmentation mode (utilizing DBs) exhausting through HRSG stacks. • Both cooling towers operating.	• HRSG stacks are located after the SCR system. • Emissions modeled are based on controlled operation of the CT's and DB's at 100% load for 8,760 hr/yr. • Emissions from the cooling towers are based on operating at 100% load for 8,760 hr/yr.

Trinity and OAQ performed an air quality modeling analysis to determine if the source exceeded the PSD significant impact levels (concentrations). If the source's concentrations exceed these levels, further air quality analysis is required. Refined modeling for PM_{10}, SO_2, NO_2 and CO was not required because the results did not exceed its significant impact levels. Significant impact levels for each operating scenario are defined by the following time periods in the Tables below with all maximum modeled concentrations from the source.

TABLE 3
Significant Impact Analysis
Worst-Case Simple Cycle Operation- Scenario #1

POLLUTANT	**TIME AVERAGING PERIOD**	**MAXIMUM MODELED IMPACTS** (ug/m^3)	**SIGNIFICANT IMPACT LEVEL** (ug/m^3)	**REFINED AQ ANALYSIS REQUIRED**
PM_{10}	24 Hour	4.62	5	No
PM_{10}	Annual	.30	1	No
NO_2	Annual	0.86[1]	1	No
CO	1 Hour	205.88	2000	No
CO	8 Hour	42.44	500	No
SO_2	3 Hour	3.93	25	No
SO_2	24 Hour	1.03	5	No
SO_2	Annual	0.02	1	No

[1]U.S. EPA NO2/NOx ratio was used to determine NO2 impacts based on the NOx emission rates. 40 CFR 51, Appendix W – Guideline on Air Quality Models.

Table 4
Significant Impact Analysis
Worst Case Combined Cycle Operation – Scenario #2

POLLUTANT	**TIME AVERAGING PERIOD**	**MAXIMUM MODELED IMPACTS** (ug/m^3)	**SIGNIFICANT IMPACT LEVEL** (ug/m^3)	**REFINED AQ ANALYSIS REQUIRED**
PM_{10}	24 Hour	3.40	5	No

PM_{10}	Annual	0.12	1	No
NO_2	Annual	0.08[1]	1	No
CO	1 Hour	39.57	2000	No
CO	8 Hour	15.2	500	No
SO_2	3 Hour	2.3	25	No
SO_2	24 Hour	0.72	5	No
SO_2	Annual	0.02	1	No

[1]U.S. EPA NO2/NOx ratio was used to determine NO2 impacts based on the NOx emission rates. 40 CFR 51, Appendix W – Guideline on Air Quality Models.

A significant impact analysis was performed for the two modeling scenarios. Concentrations are given for each scenario. Since none of the pollutants exceeded the significant impact level, a significant impact area was not determined.

An emission start-up modeling analysis was also performed to determine if start-up emissions would exceed short-term NAAQS averaging times. Start-up emissions can be higher than normal operating emissions for short periods of time. CO was the only criteria pollutant in question. The results of the analysis are shown below in Table 5.

Table 5
Emission Start-Up Modeling Analysis

POLLUTANT	**TIME AVERAGING PERIOD**	**MAXIMUM MODELED IMPACTS** (ug/m^3)	**SIGNIFICANT IMPACT LEVEL** (ug/m^3)	**REFINED AQ ANALYSIS REQUIRED**
CO	1 Hour	487.11	2000	No
CO	8 Hour	146.36	500	No

The results of the emission start-up analysis show no violation of the short-term averaging periods for CO.

O_3 does not have a significant impact level to determine whether modeling is needed. The significant emission rate for VOCs and NOx is used to determine the need for O_3 modeling. OAQ policy is to perform an air quality screening analysis for O_3 since the source's NOx emissions exceeded the significant emission rate. The RPM-IV modeling was used to calculate the O_3 concentrations as a result of NOx and VOC emissions from the source. Screening results from the ozone modeling are described in more detail in Section D of this document.

Section D

RPM-IV Inputs for Ambient and Plume injected Modes for the O_3 (VOC and NOx) NAAQS Analysis

The RPM-IV model is used as a screening tool to predict O_3 impact from the facility. It is a photochemical plume-segment model that simulates a photochemical plume by representing the plume as a series of cells across the horizon of the plume. RPM-IV consists of a Lagrangian model that follows a parcel of air pollutants as it travels downwind from a point source. Simulation of ambient air and resulting chemical transformations with a plume occur within the model to represent conditions in the atmosphere.

The RPM-IV model was run in two modes; the first mode determined ambient conditions for a day when high O_3 concentrations were recorded. The second mode injects the VOC and NOx plume from the point source into the ambient mode. The second mode will thus contain both ambient and plume injected concentrations. The concentration from the second mode is subtracted from the first mode at specified downwind distances and the difference between the two modes is the impact from the source. Source impact, which is less than 3 parts per billion (ppb) is not significant and is not subject to further refined modeling. There are five main sections which make up a RPM-IV input file. These sections and a short description of each are as follows:

1) INPUT - Define plume type, duration, location, output interval and plume definition and program flow variables.
2) CHEMIN - Define chemical mechanism RPM-IV reaction species, product species, reaction rates, and temperature.
3) SOURCES - Data for emission injections which include stack parameters and source emission rates.
4) METIN - Meteorological and ambient species concentrations, plume expansion rates and photolysis reaction rates.
5) RESULT - Parameters, which control the display of RPM-IV simulation.

The plume injected mode models the ambient conditions as well as VOCs and NOx emissions from the source. Complete stack information as well as each specie's emission rate must be input into the model. VOC and NOx specie concentrations from the source are listed in Table 6.

TABLE 6
Source Species emissions (g/sec)

CHEMICAL SPECIES/CATEGORY	EMISSION RATES (g/s)
Formaldehyde	.277
Paraffinic Carbon Bond (PAR)	.012
Nitric Oxide (NO)	1.380
Nitrogen Dioxide (NO_2)	26.07

The most current available Indiana meteorological data used is 1994. The meteorological conditions chosen are conducive to ozone formation. Since RPM-IV is used as screening model, the meteorological conditions are not specific to a locality but are more regional in nature. These meteorological conditions can occur at any given location in the state.

It is assumed that all VOCs and NOx emissions come from the one stack, since RPM-IV is used as a screening tool. The OAQ had to adjust the initial concentrations to obtain a 120 ppb ambient ozone concentration. The RPM-IV modeling results are shown in Table 7.

TABLE 7
Mirant Corporation. NAAQS Analysis for Ozone

SIMULATION TIME	DISTANCE	AMBIENT MODE SIMULATION	PLUME INJECTED SIMULATION	DIFFERENCE PLUME - AMBIENT
(minutes)	(meters)	(ppb)	(ppb)	(ppb)
0	100	28	28	0.0

60	7120	49.3	49.5	0.2
120	13100	68.2	68.0	-0.2
180	19700	84.9	84.4	-0.5
240	26700	98.6	98.2	-0.4
300	32600	109	109	0
360	40200	115	114	-1
420	51600	118	116	-2
480	63600	119	117	-2
540	81100	120	117	-3
600	101000	120	116	-4
660	115000	120	116	-4
720	126000	120	116	-4

All plume injected modes minus ambient are negative or slightly positive for every time period and every distance. The proposed electric cogeneration facility's positive impact is less than 3ppb and will not have a significant contribution to the NAAQs standard. Since there are no significant modeled contributions, further modeling for O_3 impacts from this source is not required. Impacts of less than 3 ppb are thought to be insignificant because it falls well within the range of the minimum detectable amount for a monitor.

Part E

Hazardous Air Toxics Analysis and Results

The OAQ presently requests data concerning the emission of 189 HAPs listed in the 1990 Clean Air Act Amendments (CAAA) which are either carcinogenic or otherwise considered toxic and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form Y. Any HAP emissions are subject to toxic modeling analysis.

As a precautionary measure, OAQ modeled the toxics using ISCST3 and compared the maximum modeled 8-hour concentration with the 0.5% PEL value. The maximum modeled concentrations are shown in Table 8.

Table 8
Air Toxic Analysis

Scenario 1				
	lb/hr	**g/s**	**Conc.ug/m3**	**0.5% of PEL**
Benzene	0.0031421	0.000396	0.046304	16
Dichlorobenzene	0.0017912	0.000226	0.026396	2250
Formaldehyde	0.1125700	0.014184	1.658897	4.65
Hexane	2.6918000	0.339167	39.667931	9000
Naphthalene	0.0009119	0.000115	0.013438	250
Toluene	0.0050870	0.000641	0.074965	3750
Polycyclic Organic Matter	0.0001320	0.000017	0.001946	n/a

Arsenic	0.0002989	0.000038	0.004404	0.05
Beryllium	0.0000179	0.000002	0.000264	0.01
Cadmium	0.0016477	0.000208	0.024281	0.025
Chromium	0.0020980	0.000264	0.030917	2.5
Cobalt	0.0001259	0.000016	0.001855	0.5
Manganese	0.0005630	0.000071	0.008297	25
Mercury	0.0003889	0.000049	0.005731	0.5
Nickel	0.0031421	0.000396	0.046304	5
Selenium	0.0000419	0.000005	0.000618	1
Scenario 2				
	lb/hr	**g/s**	**Conc.ug/m3**	**0.5% of PEL**
Benzene	0.0036900	0.000465	0.000914	16
Dichlorobenzene	0.0021100	0.000266	0.000523	2250
Formaldehyde	0.1320000	0.016632	0.032692	4.65
Hexane	3.1600000	0.398160	0.782631	9000
Naphthalene	0.0010700	0.000135	0.000265	250
Toluene	0.0059700	0.000752	0.001479	3750
Polycyclic Organic Matter	0.0001550	0.000020	0.000038	n/a
Arsenic	0.0003510	0.000044	0.000087	0.05
Beryllium	0.0000211	0.000003	0.000005	0.01
Cadmium	0.0019300	0.000243	0.000478	0.025
Chromium	0.0024600	0.000310	0.000609	2.5
Cobalt	0.0001470	0.000019	0.000036	0.5
Manganese	0.0006670	0.000084	0.000165	25
Mercury	0.0004560	0.000057	0.000113	0.5
Nickel	0.0036900	0.000465	0.000914	5
Selenium	0.0000421	0.000005	0.000010	1
NH3	24.40000	3.074400	7.251280	11600

None of HAPs exceed 0.5% of the PEL.

Part F

Additional Impact Analysis

All PSD permit applicants must prepare additional impacts analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source. The Mirant PSD permit application provided an additional impact analysis performed by Trinity.

Economic Growth

The proposed project is expected to create approximately 25 new full-time positions. Primarily existing residents in the Terra Haute area will fill these positions. No appreciable increase in emissions is expected as a result of any growth, which might be associated with the proposed project.

Soils and Vegetation Analysis

A list of soil types present in areas near the proposed facility was determined by a wetlands study. Soil types near the proposed facility primarily include the following: Elston Sandy Loam, Ade Sandy Loam, Warsaw Sandy Loam, Rodman Gravelly Loam, Whitaker Loam, Randolph Silt Loam, Petrolia Silty Clay Loam, Armiesburg Silty Clay Loam, Genesee Fine Sandy Loam, Shoals Silt Loam, and Wakeland Silt Loam.

Vegetation in the vicinity of the proposed facility consists mainly of grasses. No sensitive aspects of the soil and vegetation in the area surrounding the facility have been identified by the wetlands study. The secondary NAAQs, which establish the ambient concentration levels to protect soil or vegetation, will not be violated.

Federal Endangered Species Analysis

Federally endangered or threatened species are listed by the U.S. Fish and Wildlife Service; Division of Endangered Species for Indiana and includes 12 species of mussels, 4 species of birds, 2 species of bat and butterflies and 1 specie of snake. The mussels and birds listed are commonly found along major rivers and lakes while the bats are found near caves. The proposed facility is not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the industrial and residential activities in the area.

Federally endangered or threatened plants as listed by the U.S. Fish and Wildlife Service, Division of Endangered Species for Indiana list two threatened and one endangered species of plants. The endangered plant is found along the sand dunes in northern Indiana while the two threatened species do not thrive in industrialized and residential areas. The proposed facility is not expected to impact the area further.

Additional Analysis Conclusions

The nearest Class I area to the electric cogeneration facility is Mammoth Cave National Park located approximately 355 km to the south in Kentucky well outside the 100 km Class I range. The results of a Level 2 visibility analysis performed by Trinity for this source show that visibility impacts at the nearest state park (Lincoln State Park) are below the standardized screening criteria for both operating scenarios during all five years of meteorological conditions. Thus no additional analysis is required.

Finally, the results of the additional impact analysis conclude the operation of the Mirant Sugar Creek electric generation facility will have no significant impact on economic growth, soils, vegetation or visibility in the immediate vicinity or on any Class I area.

Part G

Summary of Air Quality Analysis

Mirant has applied for a PSD construction permit to construct an electric generation facility in Terre Haute, Vigo County, Indiana. The PSD application was prepared by Trinity Consultants of Itasca, Illinois. Vigo County is designated as attainment for all criteria pollutants. PM_{10}, SO_2, NO_2, VOC, and CO emission rates associated with the proposed electric generation facility exceeded the respective significant emission rates. RPM-IV modeling results showed no significant impact to ozone formation. Modeling results taken from the latest version of the ISCST3 model showed PM_{10}, SO_2, CO and NO_2 impacts were predicted to be less than the significant impact levels. Refined modeling was not required. An air toxic analysis was preformed as a precautionary measure and no modeled concentrations were above the

0.5% of PEL. Visibility impacts will be negligible. The nearest Class I area is Mammoth Cave National Park in Kentucky 355 kilometers away from the source. Additional impact analysis showed no significant impact on economic growth, soils, vegetation or visibility in the areas surrounding the proposed electric generation facility.

Appendix C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) Review

Source Name:	Mirant Sugar Creek LLC
Source Location:	6500 Darwin Road, West Terre Haute, IN 47885
County:	Vigo
Construction Permit No.:	CP-167-12208-00123
SIC Code:	4911
Permit Reviewer:	David Howard

The Office of Air Quality (OAQ) has performed the following federal Best Available Control Technology (BACT) review for the proposed 1,008 megawatt (MW) natural gas combined cycle merchant power plant, to be owned and operated by Mirant Sugar Creek LLC (Mirant). The review was performed for the four natural gas combustion turbines, four duct burners, two cooling towers and two auxiliary boilers.

The source is located in Vigo County, which is designated as attainment or unclassifiable for all criteria pollutants (VOC, NO_X, CO, PM_{10}, $S0_2$ and Lead). Therefore, these pollutants were reviewed pursuant to the Prevention of Significant Deterioration (PSD) Program (326 IAC 2-2 and 40 CFR 52.21). These pollutants are subject to BACT review because the pollutant emissions are above PSD significant threshold levels set forth in 326 IAC 2-2. BACT is an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under 326 IAC 2-2. In accordance with the "Top-Down" analysis for BACT, with guidance set forth in the USEPA 1990 draft *New Source Review Workshop Manuel*, the BACT analysis takes into account the energy, environment, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, and/or operational limitations. These reductions are needed to demonstrate that the remaining emissions after BACT implementation will not cause or contribute to significant air pollution; thereby, protecting public health and the environment.

Mirant has proposed the construction of the facility be completed in three phases. During the first phase of construction, the four combustion turbines will be constructed and used in simple cycle mode. The exhaust from the four combustion turbines will be routed through integral bypass stacks prior to construction of each associated heat recovery steam generator. During the second phase of the construction, two of the combustion turbines will be converted to combined cycle operation. Each combustion turbine will exhaust to its associated heat recovery steam generator, where the exhaust heat will be used to generate steam for electric power generation via a General Electric D11S model steam turbine. Each combustion turbine will have an associated duct burner. Duct burners will be used for power augmentation during periods of peak demand. Phase three of construction will convert the remaining two combustion turbines from simple cycle operation to combined cycle operation, as in phase two of construction.

The following BACT review is divided into two sections, one for simple cycle operation, and another for combined cycle operation. The review was conducted in this manner for two reasons. First, the project will be completed in phases, and second, the source would like to retain the ability to operate in either mode when the project is complete.

Simple Cycle Best Available Control Technology (BACT)

(A) Four Natural Gas-Fired Combustion Turbines

The four combustion turbines at the proposed Mirant Sugar Creek LLC will be General Electric 7FA (Model 7241) models equipped with General Electric dry low-NO_X combustion systems. The maximum heat input rating for each of the combustion turbines is 1490.5 million British thermal (MMBtu) on a lower heating value basis. The output of each combustion turbine, while operating in simple cycle mode, is approximately 170 MW.

(1) NO_X BACT Review

Nitrogen oxide formation during combustion consists of three types, thermal NO_X, prompt NO_X, and fuel NO_X. The principal mechanism of NO_X formation in natural gas combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most NO_X formed through the thermal NO_X is affected by three factors: oxygen concentration, peak temperature, and time of exposure at peak temperature. As these factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired turbines. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_X formation, prompt NO_X, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X, reactions occur within the flame and are typically negligible when compared to the amount on NO_X formed through the thermal NO_X mechanism. The final mechanism of NO_X formation, fuel NO_X, stems from the evolution and reaction of fuel-bonded nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is insignificant.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Catalytic Combustion (XONON)
Non-ammonia SCR (SCONOX)
Oxidation/Reduction (O/R) Scrubbing
Selective Non-catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Dry Low NO_X Burners w/Flue Gas Recirculation
Water/Steam Injection

Technically Infeasible Control Options – Two of the control options are considered to be technically infeasible: XONON and SNCR. XONON is a front-end technology that relies on flameless combustion of fuel to reduce NO_X emissions. XONON uses catalytic combustion to reduce peak flame temperatures; thus, minimizing thermal NO_X emissions. This technology has been demonstrated to be effective on small turbines (less than 1.5 MW), but has never been applied successfully to larger combustion turbines. Therefore, XONON is considered technically infeasible for controlling NO_X emissions from large combustion turbines.

SNCR is a backend technology, which uses ammonia injection similar to SCR, but operates at a higher temperature range (1,600 to 2,200 ^oF). The reaction occurs without a catalyst, effectively reducing NO_X to nitrogen and water. Since the SNCR process does not require a catalyst the process is more economically attractive than other control technologies. The operating temperature range, however, is not compatible with the proposed turbine exhaust temperature, which is approximately 1,150 ^oF. Furthermore, this control technology has only been applied to boilers and incinerators, but not to large natural gas turbines. Therefore, this control technology is considered to be technically infeasible for the proposed combustion turbines.

Ranking of Technically Feasible Control Options – The following technically feasible NO_X control options are ranked by control efficiency:

Rank	Control	Facility	Emission Limit (ppmvd)	Control Efficiency
1	SCONOX	Turbine	2.0 – 4.0	+90%
2	Selective Catalytic Reduction (SCR)	Turbine	2.5 – 4.5	60% - 90%
3	Oxidation/Reduction	Turbine	N/A	90%

	Scrubbing			
4	Dry Low NO_X Burners w/FGR	Turbine	9	N/A
5	Water/Steam Injection	Turbine	25 – 75	N/A

Discussion - Oxidation/Reduction scrubbing is a process by which a scrubbing agent, such as ozone or sodium chlorite, is used to oxidize NO_X. The addition of an O/R scrubber would require the combustion of additional natural gas in order to eliminate a wet plume effect. The combustion of additional fuel will increase NO_X as well as other pollutants. The cost of an oxidation/reduction system is also extensive; both initial and cost per ton of NO_X removed. Additionally, the RBLC has no entries for an oxidation/reduction system used in conjunction with a natural gas fired turbine. Therefore, an oxidation/reduction system will not be considered further in this BACT review as control for NO_X.

SCONOX

SCONOX became commercially available for all sizes of gas turbines, including those larger turbines not previously considered compatible with the technology, within recent months.

The SCONOX system can operate effectively at temperatures ranging from 300 ^oF to 700 ^oF. The SCONOX system can achieve greater than ninety (90) percent control efficiency for NO_X and CO. The SCONOX system also controls NMHC (non-methane hydrocarbons). Based on data submitted by SCONOX vendors, the control efficiency for NMHC is around fifty (50) percent. Control efficiencies are dependent on pollutant concentrations and the combustion unit's exhaust temperature. SCONOX achieved record lows for NOx and CO emissions at the merchant Sunlaw Federal Power Plant in California. Based on a fifteen minute rolling average, these units are emitting 0.8 ppm for NO_X and 0.5 ppm for CO. Currently vendors are guaranteeing 2.0 ppm for NO_X.

SCONOX is installed at the back end of the combustion units where exhaust temperatures are within the temperature window or the system could be installed after a heat recovery steam generating (HRSG) unit. The turbine exhaust gases from simple cycle turbines could be ducted to an air-to-air system, a water-to-air closed loop system or a waste recovery boiler system depending on the type of application. These heat exchanger systems are able to reduce the exhaust gas temperature to 650 ^oF. A blower is also required to provide all necessary cooling air to the heat exchanger. Currently, there is research being done to develop a high temperature SCONOX catalyst that will operate at greater than 700 ^oF exhaust gas temperature. Thus a heat exchanger system is not necessary. Currently, SCONOX has not been installed on turbines with exhaust temperatures higher than 700 ^oF. The low NO_X emission rate of 2.0 ppmvd will not be guaranteed for units that have an exhaust temperature above 700 ^oF.

SCONOX typically utilizes a platinum catalyst, which has a life expectancy range of 5-7 years. The type of catalyst metal used is considered a “precious metal” and is not considered to be hazardous. Therefore, there are no significant negative environmental impacts associated with utilizing the SCONOX system.

Because SCONOX has not been installed on simple cycle turbines with higher exhaust temperatures, vendors will not guarantee controlled emission rates for units such as the project proposed. Since there is no specific guarantee for the control of emissions and the high cost of control, this technology is eliminated from further consideration as a control option for NO_X and CO.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction is a NO_X control process, which uses a reaction with ammonia in the presence of a catalyst to from N_2 and H_2O. An important factor when using SCR is temperature. The common reduction catalyst for this technology requires low temperatures (400 – 800 ^oF) in order for the reaction to occur. Operating above maximum operating temperature results in the oxidation of ammonia to either NO_X or ammonia nitrate. High temperature catalysts are available, and are able to operate up to 1,100 ^oF.

Based on a review of the RBLC and other sources there are four simple cycle combustion turbine installations that presently operate with a high temperature catalyst. One of the facilities, located Southern California, has experienced significant operational problems with the original system and has applied to the local Air Board for permission to remove the system. The second facility, located in Northern California, has very limited operation, and has no operational data to support the effectiveness of the SCR system. The third installation, located outside of Sacramento, has been utilizing SCR successfully at the facility. This facility, unlike the proposed source, uses GE LM 6000 turbines. These turbines are aero-derivative turbines, which means the exhaust gas temperatures are considerably lower than with other turbines operating in simple cycle mode. The lower temperature enables the SCR system to use a tungsten-based catalyst opposed to a high temperature catalyst. It should also be noted that all three of these simple cycle operations using SCR are considerably smaller than the proposed facility. The fourth facility, Puerto Rico Power Authority, is equipped with three ABB GT11N turbines firing distillate oil using SCR for NO_X control. The facility has been in operation since 1997, but is currently in negotiation with EPA over their ability to consistently meet the 10 ppm NO_X outlet emission rate.

Ammonia slip is also a concern when operating at high temperatures. SCR manufactures estimate up to 20 ppm or more of unreacted ammonia emissions when operating at very high levels. Cost to control NO_X emissions from simple cycle operations utilizing SCR control can be extensive. Using the methodology set forth in the Office of Air Quality Planning and Standards Alternative Control Techniques Document NO_X emission costs were estimated to be $10,845 per ton of NO_X removed. This estimate is based on removal from 9.0 ppm to 3.5 ppm. Based on the issues above and the lack of continuous compliance data to support the use of high temperature SCR to control NO_X emissions from simple cycle operations, SCR will be eliminated from further consideration in this BACT analysis.

Water/Steam Injection

Water/Steam injection emission rates for NO_X can vary from 25 ppm to 75 ppm. The facility has proposed an NO_X emission rate of 9.0 ppm with the use of dry low NO_X combustors. This limit is considerably lower than what is achievable through the use of water/steam injection. Also water/steam injection has the potential to increase CO and hydrocarbon emissions due to the lowering of the flame temperature associated with water/steam injection. Therefore, water/steam injection will be eliminated as BACT for NO_X control.

<u>Existing BACT Emission Limitations</u> – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The following table represents entries in the RBLC of similar operations.

Company	Facility	Throughput	Emission Rate (ppm@15%O2)	Control Description
Proposed Sugar Creek Facility	Turbine (4)	1490.5 MMBtu/hr	9	Dry Low NO_X Combustor

Tiger Bay LP, FL	Turbine	1614.8 MMBtu/hr	15	Dry Low NO_X Combustor
Auburndale Power Partners, FL	Turbine	1214 MMBtu/hr	15	Dry Low NO_X Combustor
Florida Power Corp. Polk County Site, FL	Turbine	1510 MMBtu/hr	12	Dry Low NO_X Combustor
Santa Rosa Energy LLC, FL	Turbine	241 MW	9.8	Dry Low NO_X Burner
Baltimore Gas & Electric, MD	Turbine	140 MW	15	Dry Low NO_X Burners
Oleander Brevard, FL	Turbine	170 MW	9	Dry Low NO_X Combustor
Tenaska, GA	Turbine	170 MW	15	Dry Low NO_X Combustor
JEA Baldwin, FL	Turbine	170 MW	10.5	Dry Low NO_X Combustor

The table above lists projects of similar size combustion turbines, approximately 170 MW per turbine, to the proposed facility. The emission rates range from 9 to 15 ppmvd, as well as the time used to determine compliance. Dry low NO_X combustors are considered BACT for simple cycle combustion turbines, with an achievable 9 ppmvd emission limit.

Conclusion – Based on the information presented above, the NO_X BACT for the proposed facility will be the use of natural gas as fuel, and dry low NO_X combustors with a limit of 9 ppmvd corrected to 15% O_2 based on a 3 hour averaging period, and utilizing only natural gas as a fuel.

During periods of startup and shutdown (less than 50 percent load) the NO_X emission limit for each combustion turbine stack shall not exceed 80 ppmvd @15% O_2 and 48 ppmvd @15% O_2, respectively. The startup or shutdown period shall not exceed a period of two (2) hours.

(2) CO BACT Review

Carbon monoxide emissions from combustion turbines are a result of incomplete combustion of natural gas. Improperly tuned turbines operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

Control Options Evaluate – The following control options were evaluated in the CO BACT review:

Thermal Oxidation
Catalytic Oxidation
Improved Air/Fuel Mixing w/Good Design and Operation

Discussion - A catalytic oxidation system utilizes a passive reactor system, which consists of a grid coated with a catalyst. The turbine's exhaust is passed over the catalyst, where the CO is oxidized to CO_2. In these types of systems, typically 80-90 percent of the CO is oxidized to CO_2. Based on the RBLC, there is only one simple cycle operation with an issued permit requiring a catalytic oxidation system for CO control under BACT. The facility is located in Colorado and was permitted for a simple cycle combustion turbine using natural gas as the primary fuel. The facility was never constructed under the originally issued permit. The source revoked the permit and requested a new one for smaller turbines, which did not exceed PSD thresholds. The most stringent CO limitation found in the RBLC for a gas fired combustion turbine is 1.8 ppmvd corrected to 15% O_2. The source, Newark Bay Cogeneration Partnership L.P., volunteered to use the catalytic oxidation system to avoid LAER threshold levels and Emissions Offsets. Currently the RBLC and other states have confirmed that catalytic oxidation has not been required for simple cycle and combined cycle operation reviewed under PSD BACT

A thermal oxidation system is equivalent to adding another combustion chamber where more O_2 is supplied to complete the oxidation of CO. The flue gas must be reheated to the temperature at which CO oxidation can take place. Due to this, more natural gas must be combusted in order to bring the exhaust to the appropriate temperature. In addition the RBLC does not indicate that this technology has been applied to natural gas-fired turbines. Therefore, thermal oxidation will be eliminated as BACT for CO emission control. Improved air/fuel mixing with good design/operation is the next type of combustion control evaluated. General Electric will guarantee a CO emission rate down to 9 ppmvd corrected to 15% O_2 on the 7FA model. The 7FA model has lower CO emission than the 7EA model due to a design difference. The main component of the design that makes the 7FA model's CO emissions less than 7EA model is the post flame temperature. The hotter temperature results in more burning of CO emissions. For this facility GE has guaranteed a CO emission limit of 9 ppmvd corrected to 15% O_2, at steady state conditions. Proper operation, temperature, and oxygen availability will also minimize CO spikes during normal operation.

Existing BACT Emission Limitations – The following table represents recently issued combustion turbine permits that use GE turbines without add on control and were permitted as BACT:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Sugar Creek Facility	Turbine	1490.5	9	ppm	DLN Combustors
RockGen Energy, WI	Turbine	NA	12	ppm	DLN Combustors
LS Power Nelson, IL	Turbine	2166	0.047	lb/MMBtu	DLN Combustors
LS Power Kendall, IL	Turbine	2166	0.045	lb/MMBtu	DLN Combustors
Auburndale Power Partners, FL	Turbine	1214	15	ppm	Good Combustion
Champion Intl. Clean Energy, ME	Turbine	175 MW	9	ppm	NA
Doswell L.P., VA	Turbine	1261	25	lb/hr	Combustor Design
Lakewood Cogeneration, NJ	Turbine	1190	30.94	lb/hr	Turbine Design
Portland General Electric, OR	Turbine	1720	15	ppm	Good Combustion
Selkirk Cogeneration L.P., NY	Turbine	1173	10	ppm	Combustion Control

The proposed Sugar Creek facility offers one of the lowest CO emission rates in the RBLC that does not require an oxidation catalyst or does not represent LAER. Also, there is a correlation between NO_X emission rates and CO emission rates. As stated previously, CO is controlled by ensuring high temperatures to complete combustion. Conversely, low NO_X emissions are achieved by decreasing flame temperatures. Therefore, there is a compromise in the flame temperature to achieve the lowest NO_X emission rate while optimizing CO emission rates.

Conclusion – Based on the information presented above the CO BACT shall be the use of good design and operation with the natural gas as the sole fuel. The emission limit for each combustion turbine will be 9 ppmvd corrected to 15% O_2 over a 24 hour averaging period.

During periods of startup and shutdown (less than 50 percent load) the CO emission limit for each combustion turbine stack shall not exceed 150 ppmvd @ 15% O_2 and 90 ppmvd @ 15% O_2, respectively. The startup or shutdown period shall not exceed a period of two (2) hours. Duct burners shall not be operated until normal operation begins.

(3) PM BACT Review

There are three potential sources of filterable particulate emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter in the fuel for natural gas-fired sources such as the proposed power generation plant. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to its compression and use as combustion air in the combustion turbine. Finally, the potential for soot formation in a natural gas-fired combustion turbine is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable particulate origination from the turbine.

There are two sources of condensible particulate emissions from combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist, which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the proposed power plant, there should be no condensible organics originating from the source because the main components of natural gas (i.e., methane and ethane) are not condensible at the temperatures found in a Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensible particulate matter from natural gas-fired combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and in the ambient air is combusted and then cools.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Venturi Scrubber
Good Design/Operation

Technically Infeasible Control Options – Traditional add-on particulate control, such as the above listed, have not been applied to natural gas fired combustion turbines. High temperature regimes, fine particulate and low particulate rates coupled with significant airflow rates make add-on particulate control equipment technically infeasible.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The following table represents operations that are similar size:

Company	Facility	Throughput (MMBtu/hr)	Emission Rate (lb/MMBtu)	Compliance Status
Proposed Sugar Creek Facility	Turbine	1490.5	0.012	Not Yet Tested (5 and 202)
Selkirk Cogen., NY	Turbine (7FA)	1173	0.014	Compliant (Condensibles not tested)
	Duct Burner	206		
Whiting Clean Energy, IN	Turbine (7FA)	1735	0.0045	Not Yet Tested (5 & 202)
	Duct Burner	821	0.0045	
LSP Nelson, IL	Turbine	2166	0.0193	Not Yet Tested (5 & 201A)
	Duct Burner	350		
LSP Kendall, IL	Turbine	2166	0.0183	Not Yet Tested (5 & 201A)
	Duct Burner	350		
Gordonsville Energy, VA	Turbine (7EA)	1430	0.0035*	Compliant (Method 5)
Duke Power Lincoln, NC	Turbine (7 Frame)	1313	0.0038*	Compliant (201 or 201A)
CP&L Harstville, SC	Turbine W501	1521	0.0039*	Noncompliant (Method 5)
Hardee Station, FL	Turbine (7EA)	1268	0.0039*	Not Specified (Method 5)
CP&L Goldsboro 1, NC	Turbine (7FA)	1908	0.0047*	Not Yet Tested (201 or 201A)
CP&L Goldsboro 2, NC	Turbine (7FA)	1819	0.0049*	Not Yet Tested (201 or 201A)
Ecoelectrica L.P., PR	Turbine W501F	1900	0.005*	Not Tested (201)
SMEPA-Mosell, MS	Turbine (7EA)	1299	0.0057*	Compliant (Method 5)
Saranac Emergy, NY	Turbine (7EA)	1123	0.0062*	Compliant (Method 5)
Lakewood Cogen, NJ	Turbine (ABB GT11N)	1073	0.0023	Compliant (201A & 202)
Reliant Energy, IL	Turbine	634 MW	0.0095*	Not Specified (Method 5 and 201A)
Tiger Bay L.P., FL	Turbine (7FA)	1700	0.0053*	Not Specified (Method 5)
Gorham Energy, ME	Turbine (ABB-GT 24	870 MW	0.009	Never Constructed

* These limits do not include condensible PM_{10} (Method 202)

Compliance with the particulate matter limits presented in the above table is demonstrated based on measurement of either the filterable particulate fraction only or the combine filterable and condensible particulate fractions. Because the majority if not all of the filterable particulate is PM_{10}, and because vendor information indicates that at least half of the total particulate is condensible, the limits based solely on demonstrating compliance using only the filterable component were considered none representative for the purpose of comparison. Therefore, these limits were eliminated from the review.

Two other facilities have lower limits than the proposed Sugar Creek facility are Whiting Clean Energy and Lakewood Cogeneration. The Whiting Clean Energy facility is located in a PM_{10} nonattainment area and, therefore is subject to LAER and PM_{10} emission reduction credits. The source took a lower limit in order to avoid PM_{10} offset credits, but has not yet demonstrated compliance with the lower limit. While the Lakewood Cogeneration facility has a lower PM_{10} emission limit the corresponding NO_X and CO emission are higher than the proposed Sugar Creek facility. It is not expected that the proposed Sugar Creek facility will emit more particulate matter than these two facilities because there is no add-on control technology for combustion turbine. The top level of control for a combustion turbine is considered to be a clean burning fuel. Natural gas is the cleanest burning fuel and is, therefore, considered the best control technology.

As stated above, the combustion of natural gas generates negligible amounts of particulate matter. There is a degree of variability inherent to the test method (Method 202) used to determine compliance with the proposed particulate limits. The variability from this test result is from several factors. First, there is such a large volume of exhaust gas stream compared to small amount of particulate. For example, the concentration of particulate matter could be the same for two gas steams. However, if one of the gas streams is at a lower flow rate, the pound per hour emission rate would be less than a gas stream that is at a higher flow rate. Second, as with any test, there is a possibility of human error, which has the potential to bias the test higher or lower than what is actually being emitted. In addition, the inlet air filters are not a hundred percent efficient, so any particulate that passes through the filters will also leave the exhaust stack. The higher the background concentration of particulate matter in the ambient air the more will pass through the combustion turbine stack. Ambient air particulate concentration can vary depending on location, activity in the area, and weather conditions.

<u>Conclusion</u> – Based on the information presented above, the PM BACT shall be the use of natural gas and good design and operation. The total PM emissions from each turbine shall not exceed 0.012 lb/MMBtu (18 pounds per hour) on a lower heating value basis.

(4) SO_2 BACT Review

Emissions from natural gas-fired turbines are low because pipeline quality gas has a low sulfur content. A properly designed and operated turbine utilizing a low sulfur natural gas will have low SO_2 emissions.

<u>Control Options Evaluated</u> – the following control options were evaluated in the BACT review:

Wet Lime Scrubber
Spray Dryer–ESP/Lime Injection-ESP

<u>Discussion</u> – A wet lime scrubber uses a lime solution as a scrubbing medium to control SO_X emissions. Lime scrubbers have been widely used to control SO_X from power plants, however those installed have typically been at coal-fired and other high sulfur oil-fired combustion units. The addition of a wet lime scrubber would require the addition of fuel to control the exit gas stream to eliminate a wet plume effect. Therefore, additional fuel would be required to create a dry plume, thus increasing emissions of other pollutants. In addition, a wet scrubber creates solid waste, which first must be dewatered, and then landfilled.

Spray dryer-ESP technology uses a lime slurry which is injected by a spray dryer in the flue gas in the form of fine droplets. The droplets absorb SO_X from the flue gas and then become dry particles due to the evaporation of water. The dry particles are then captured by and ESP downstream of the spray dryer.

Both of the listed control options are economically infeasible, with the cost per ton of SO_X removed between six and ten million dollars. The RBLC lists many entries with a fuel specification of natural gas, good combustion practices and good design and operation. A properly designed and operated turbine using low sulfur natural gas is an effective control technology available for the control of SO_X emissions from boilers.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), and good combustion practices. The SO_X emission limit from each turbine shall be 4.2 lb/hr.

(5) VOC BACT Review

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good control.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Thermal Oxidation
Catalytic Oxidation
Good Design/Operation

Discussion – Thermal oxidation is a proven technology to control VOC emissions, however it is rarely used on natural gas-fired sources. Because of the low VOC concentration generated from the use of natural gas and good combustion practice, thermal oxidation technology is ineffective. In addition, the thermal oxidation technology requires additional combustion of natural gas, which in turn would generate more emissions.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbon to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion ranges from 650 to 1000 ^oF. In addition the use of an oxidation catalyst would require additional combustion of natural gas, which increase NO_X and CO emissions.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for combustion turbines:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Sugar Creek Facility	Turbine	1490.5	0.0024	lb/MMBtu	Combustion Control
Carolina Power and Light, NC	Turbine	1907.6	0.0015	lb/MMBtu	Combustion Control
Duke Power Co.	Turbine	1313	0.0015	lb/MMBtu	Combustion

Lincoln Turbine Station					Control
Auburndale Power Partners	Turbine	1214	0.005	lb/MMBtu	Combustion Control
Berkshire Power Development, MA	Turbine	1792	0.0035	lb/MMBtu	Combustion Control
Duke Power Lincoln, NC	Turbine	1247	0.004	lb/MMBtu	Combustion Control
Florida Power Corporation Polk County, FL	Turbine	1510	7	ppmvw	Good Combustion
[1]LS Power Kendall, IL	Turbine	2166	0.0099	lb/MMBtu	Good Combustion
[1]LS Power Nelson, IL	Turbine	2166	0.0104	lb/MMBtu	Good Combustion

[1]Combined cycle project starting in simple cycle operation. The emission rate is for simple cycle operation

The RBLC does not list any entries that require an oxidation catalyst for a combined cycle operation reviewed under PSD BACT. Also, an oxidation catalyst would not be economically feasible because of the lower inlet CO emissions associated with new combustion technology. The Duke Power Lincoln and Carolina Power & Light generation plants have VOC emission rates lower than the proposed facility. The difference in emissions is due to different turbine models and site specific conditions. While the VOC emissions are lower for these two facilities their corresponding NOX and CO emissions are higher.

Conclusion – Based on the information presented above, the VOC BACT for each turbine at the proposed Sugar Creek facility shall be good design and operation. Each combustion turbine shall be limited to 0.0024 lb/MMBtu (on a lower heating value basis), which is equivalent to 3.7 lb/hr VOC.

Combined Cycle Best Available Control Technology (BACT)

(A) Four Natural Gas-Fired Combustion Turbines and Four Natural Gas-Fired Duct Burners

The four combustion turbines at the proposed Mirant Sugar Creek LLC will be General Electric 7FA (Model 7241) models equipped with General Electric dry low-NO_X combustion systems. The maximum heat input rating for each of the combustion turbines is 1490.5 MMBtu/hr on a lower heating value basis. Auxiliary or supplemental duct firing is included as part of each combustion turbine/heat recovery steam generator. The maximum heat input capacity for each duct burner is 300 MMBtu/hr on a higher heating value basis. Auxiliary duct firing will be used to increase electric power production during periods of peak electrical demand and will be limited to 13% of the year (1,314 hr/yr).

(1) PM BACT Review

There are three potential sources of filterable particulate emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter in the fuel for natural gas-fired sources such as the proposed power generation plant. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to compression and used as combustion air in the combustion turbine. Finally, the potential for soot formation in a natural gas-fired combustion turbine with duct burners is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable particulate origination from either the turbine or duct burner.

There are two sources of condensible particulate emissions from combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the proposed power plant, there should be no condensible organics originating from the source because the main components of natural gas (i.e., methane and ethane) are not condensible at the temperatures found in a Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensible particulate matter from natural gas-fired combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and in the ambient air is combusted and the cools.

Control Options Evaluated – The following control options where evaluated in the BACT review:

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Venturi Scrubber

Technically Infeasible Control Options – Traditional add-on particulate control, such as the above listed, have not been applied to natural gas fired combustion turbines. High temperature regimes, fine particulate and low particulate rates coupled with significant airflow rates make add-on particulate control equipment technically infeasible.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emissions limit data for industrial processes throughout the United States. The follow table represents issued emission rates for GE Frame 7 turbines.

Company	Facility	Throughput (MMBtu/hr)	Emission Rate (lb/MMBtu)	Control Description
Proposed Sugar Creek Facility	Turbine (7FA)	1490.5	0.012	Good Combustion
	Duct Burner	300	0.0075	
Selkirk Cogen, NY	Turbine (7FA)	1173	0.012	Good Combustion
	Duct Burner	206		
Whiting Clean Energy, IN	Turbine (7FA)	1735	0.0104	Good Combustion
	Duct Burner	821		
LSP Nelson, IL	Turbine	2166	0.0193	Good Combustion
	Duct Burner	350		
LSP Kendall, IL	Turbine	2166	0.0183	Good Combustion
	Duct Burner	350		
Gordonsville Energy, VA	Turbine (7EA)	1430	0.0035*	Good Combustion
Duke Power Lincoln, NC	Turbine (7 Frame)	1313	0.0038*	Good Combustion
CP&L Harstville, SC	Turbine W501	1521	0.0039*	Good Combustion
Hardee Station, FL	Turbine (7EA)	1268	0.0039*	Good Combustion
CP&L Goldsboro 1, NC	Turbine (7FA)	1908	0.0047*	Good Combustion

CP&L Goldsboro 2, NC	Turbine (7FA)	1819	0.0049*	Good Combustion
Ecoelectrica L.P., PR	Turbine W501F	1900	0.005*	Good Combustion
SMEPA-Mosell, MS	Turbine (7EA)	1299	0.0057*	Good Combustion
Saranac Emergy, NY	Turbine (7EA)	1123	0.0062*	Good Combustion
Lakewood Cogen, NJ	Turbine (ABB GT11N)	1073	0.0023	Good Combustion

* These limits do not include condensible PM_{10} (Method 202)

Compliance with the particulate matter limits presented in the above table is demonstrated based on measurement of either the filterable particulate fraction only or the combined filterable and condensible particulate fractions. Because the majority if not all of the filterable particulate is PM_{10}, and because vendor information indicates that at least half of the total particulate is condensible, the limits based solely on demonstrating compliance using only the filterable component were considered non representative for the purpose of comparison. Therefore, these limits were eliminated from the review.

Two other facilities have lower limits than the proposed Sugar Creek facility are Whiting Clean Energy and Lakewood Cogeneration. The Whiting Clean Energy facility is located in a PM_{10} nonattainment area and, therefore is subject to LAER and PM_{10} emission reduction credits and has not demonstrated compliance with the lower limit. The source took a lower limit in order to avoid PM_{10} offset credits. While the Lakewood Cogeneration facility has a lower PM_{10} emission limit the corresponding NO_X and CO emission are higher than the proposed Sugar Creek facility. It is not expected that the proposed Sugar Creek facility will emit more particulate matter than these two facilities because there is no add-on control technology for combustion turbine. The top level of control for a combustion turbine is considered to be a clean burning fuel. Natural gas is the cleanest burning fuel and is, therefore, considered the best control technology.

As stated above, the combustion of natural gas generates negligible amounts of particulate matter. There is a degree of variability inherent to the test method (Method 202) used to determine compliance with the proposed particulate limits. The variability from this test result is from several factors. First, there is such a large volume of exhaust gas stream compared to small amount of particulate. For example, the concentration of particulate matter could be the same for two gas steams, however, if one of the gas streams is at a lower flow rate the pound per hour emission rate would be less than a gas stream that is at a higher flow rate. Second, as with any test there is a possibility of human error, which has the potential to bias the test higher or lower than what is actually being emitted. In addition, the inlet air filters are not a hundred percent efficient, so any particulate that passes through the filters will also leave the exhaust stack. The higher the background concentration of particulate matter in the ambient air the more will pass through the combustion turbine stack. Ambient air particulate concentration can vary depending on location, activity in the area, and weather conditions.

Conclusion – Based on the information presented above, the PM/PM_{10} BACT shall be the use of natural gas as the sole fuel, good combustion practice, and a duct burner fuel usage limitation equivalent to 1,314 hours per year. Each turbine shall not exceed 0.012 lb/MMBtu on a lower heating value basis, which is equivalent to 18 pounds per hour. Emissions from each combustion turbine stack shall not exceed 20.2 lb/hr when the turbine is operating in combined cycle mode and its associated duct burner is firing.

(2) NO_X BACT Review

Oxides of nitrogen (NO_X) emissions from combustion turbines consist of two types: thermal NO_X and fuel NO_X. Thermal NO_X is created by the high temperature reaction of nitrogen and oxygen in the combustion air. The amount formed is a function of the combustion chamber design and the combustion turbine operating parameters, including flame temperature, residence time, combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_X formation is an exponential function of the flame temperature. Fuel NO_X is formed by the gas-phase oxidation of char nitrogen. Fuel NO_X formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the combustion oxygen levels. Natural gas contains a negligible amount of fuel nitrogen, therefore, fuel NO_X is insignificant. As such, the only type of NO_X formation from natural gas combustion is thermal NO_X.

Control Options Evaluated – The following control options and work practice techniques were evaluated in the BACT review:

Dry Low NO_X Burners w/Flue Gas Recirculation
Water/Steam Injection
SCONOX System
Selective Catalytic Reduction (SCR)
Selective Non-Catalytic Reduction (SNCR)
Catalytic Combustion (XONON)

Technically Infeasible Control Options – Three of the control options were considered to be technically infeasible: water/steam injection, selective non-catalytic reduction (SNCR), and catalytic combustion (XONON). Water and steam injection directly into the flame area of the turbine combustor provides a heat sink that lowers the flame temperature and reduces thermal NO_X formation. The water or steam injection rate is typically described on a mass basis by a water-to-fuel ratio or a steam-to-fuel ratio. Higher water-to-fuel or steam-to-fuel ratios translate to greater NO_X reductions, but may also increase emissions of CO and other hydrocarbons, reduce turbine combustion efficiency, increase maintenance requirements and cause potential flame outs. Water or steam injection control is limited to controlling NO_X to 25 ppm @ 15% O_2. Because the proposed GE turbines will be equipped with DLN combustors that reduce NO_X to 9 ppm corrected to 15% O_2, which is lower than that attainable with wet control, this control alternative utilizing water or steam injection will be excluded from further BACT consideration for the source.

Selective non-catalytic reduction requires the addition of ammonia or a similar type of selective reductant to an area where the temperature is in the 1,500 to 2,000 ^oF range. There is no operating range associated with the proposed turbines that meets these requirements. The exhaust temperature at the turbine exit is expected to be approximately 1,150 ^oF during normal operation.

Catalytic combustion (XONON) is a recently developed front-end technology that relies on flameless combustion of fuel to reduce NO_X emissions. The XONON system prevents the formation of thermal NO_X during combustion of the fuel by oxidizing a fuel/air mixture across small catalyst beds to burn fuel at less that the flame temperature at which thermal NO_X formation begins. The system does use a partial flame downstream to complete the combustion process, thus, producing small amounts of NO_X emissions. XONON technology replaces the traditional diffusion or lean premix combustion cans of the combustion turbine. This represents the only catalytic control that may lend itself for a reasonable retrofit to existing units. This technology has only been demonstrated, and being offered on small turbines (i.e. no larger than 1.5 MW). Additionally the RBLC does not list any entries for catalytic combustion as BACT for combustion turbines.

Ranking of Remaining Feasible Control Options – The following technically feasible NO_X control options were are ranked by efficiency:

Rank	Control	Facility	Control Efficiency	Emission Limit (ppm)
1	SCONOX w/Low NOX Burners	Turbine	90+	2.0-4.5
		Duct Burner	90+	2.0-4.5
2	SCR w/Dry Low NOX Burners	Turbine	80-90+	2.5-4.5
		Duct Burner	80-90+	2.5-4.5
3	Dry Low-NOX Burners	Turbine	N/A	9-15
		Duct Burner	N/A	20-30

Discussion – Dry Low-NOx (DLN) combustion utilizes lean combustion and reduced combustor residence time as NO_X control techniques to reduce emissions from the turbine. In the past gas turbine combustors were designed for operation with one to one air to fuel stoichmetric ratio. However, with fuel-lean combustion, the additional excess air cools the flame and reduces the rate of thermal NO_X formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors resulting in the combustion gases being at a high temperature for a shorter time, thus reducing the rate of thermal NO_X formation. The dry low-NOx burners are an integral design feature to the GE 7FA turbines. Based on GE vendor specifications, the combustion turbines can achieve an emission limit of 9 ppmvd corrected to 15% O_2.

SCONOX

The SCONOX system is a new flue gas clean up system that uses a coated oxidation catalyst to remove both NO_X and CO, and offers promise of reducing NO_X to below 3 ppmvd. The oxidation catalyst oxidizes CO to CO_2 and NO_X to NO_2. The NO_2 is then absorbed onto a potassium carbonate coated catalyst. Because the potassium carbonate coating is consumed as part of the absorption step it must frequently be regenerated. To regenerate the potassium coating it is contacted with a reducing gas, hydrogen, in the absence of oxygen. During regeneration flue gas dampers are used to isolate a section of the coated catalyst from the flue gas path so the regeneration gases can be contacted with the catalyst. Once the catalyst has been isolated from the oxygen rich turbine exhaust, natural gas is used to generate hydrogen gas. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. Hydrogen reacts with potassium nitrites and nitrates during regeneration to form H_20 and N_2 that is emitted from the stack.

SCONOX catalyst is subject to the same fouling and masking degradation that is experienced by any catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or internal sources, accumulate on the surface of the catalyst, eventually masking active catalyst sites over time. Catalyst aging is also experienced with any catalyst operating within a turbine exhaust stream. However, due to the lack of experience and data with this system, it is difficult to confidently predict the life and cost of the catalyst. At this time, the SCONOX system has only been applied on small industrial, cogeneration turbines. The valving system used during the regeneration step to isolate the catalyst from the exhaust gas flow requires a complete redesign before the system can be scaled up for use on units larger than that which is currently operating. There is long term maintenance and reliability concerns related to the mechanical components on the large-scale turbine projects due to the number of parts that must operate reliably within the turbine exhaust environment.

Selective Catalytic Reduction (SCR)

The SCR system is a post combustion control technology in which injected ammonia reacts with NO_X in the presence of a catalyst to form water and nitrogen. Technical factors related to this technology include the catalyst reactor design, optimum operating temperatures, sulfur content of the fuel, and ammonia slip. Sulfur content of the fuel can be a concern for turbines that use an SCR system and burn high sulfur fuels. However given pipeline quality natural gas catalyst life can be expected to be reasonable. Catalysts promote partial oxidation of sulfur dioxide to sulfur trioxide, which combines with water to form sulfur acidic mist.

SCR, like all systems utilizing a catalyst, is subject to catalyst deactivation over time. Catalyst deactivation occurs through physical deactivation and chemical poisoning. The level of NO_X emission reduction is a function of the catalyst volume and ammonia to NO_X ratio. Typically SCR catalyst manufacturers will guarantee a life of three years for low emission rate, high performance catalyst systems.

A final consideration with an SCR system is ammonia slip. Manufacturers typically estimate 10-20 ppm of unreacted ammonia emissions when making NO_X control guarantees at very low emission levels. However, a properly operated SCR system will typically have small amounts of ammonia slip. To achieve low NO_X limits, SCR vendors suggest a higher ammonia injection rate than what is stoichiometrically required, which results in ammonia slip. Ammonia slip can also occur when the exhaust temperature falls outside the optimum catalyst reaction, or when the catalyst becomes prematurely fouled or exceeds its life expectancy. For a given catalyst volume, higher NH_3 to NO_X ratios can be used to achieve a higher NO_X emission reduction rate.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The following table represents emission limitations established for similar sized combustion turbines:

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm@15%O_2	Control Description
Proposed Sugar Creek Facility	Turbine	1490.5	3.0 (3-hr block avg.)	DLN + SCR
	Duct Burner	300		
Casco Ray Energy CO, ME	Turbine	2x170 MW	3.5 (3-hr block avg.)	DLN + SCR
LSP-Cottage Grove LP, MN	Turbine	1988	4.5	DLN + SCR
Portland General Electric, OR	Turbine	1720	4.5	SCR
Hermiston Generating Co.	Turbine	1696	4.5	SCR
SPA Campbell Soup, CA	Turbine	1257	3.0 (3-hr block avg.)	DLN + SCR
Sunlaw Cogen., CA	Turbine	32 MW	2.5 (annual avg.)	WI + SCONOX
Gorham Energy Limited, ME	Turbine	3x300 MW	2.5 (3-hr block avg.)	DLN + SCR
Wood River Refinery Cogen., IL	Turbine	3x211	3.5 (24-hr avg.)	DLN + SCR
Sithe / Independence Power, NY	Turbine	4x2133	4.5	DLN + SCR
Mystic Station, MA	Turbine	275 MW	2.0 (1-hr avg.)	DLN + SCR

Cabot Power Corp, MA	Turbine	350 MW	2.0 (1-hr avg)	DLN + SCR
Whiting Clean Energy, IN	Turbine	545 MW	3.0 (3-hr rolling avg)	DLN + SCR

Based on the RBLC review, there are two facilities that have been permitted with a 2.0 ppm emission limit utilizing SCR. However, neither of these two sites has been constructed, so the 2.0 ppm limit has not been demonstrated as feasible. Also, these two facilities are located in nonattainment areas and are, therefore, subject to LAER. Two other facilities have been permitted at 2.5 ppm, but only one is in operation (Sunlaw Cogeneration). This facility has CEM data to support the unit can achieve 2.5 ppm utilizing SCONOX. The Sunlaw Cogeneration facility is substantially smaller than the proposed facility at 32 MW opposed to the proposed Mirant Sugar Creek facility at 1,008 MW. The SCONOX technology has been demonstrated to be effective on smaller turbines, however, as discussed above a SCONOX system has long term maintenance and reliability concerns related to mechanical components on large scale turbine projects.

SCR has become a widely used and accepted control technology for NO_X emission control for natural gas-fired combustion turbines. Facilities that have been permitted utilizing SCR have been permitted from 4.5 ppmvd @ 15% O_2 down to 2 ppmvd @ 15% O_2. The SPA Campbell Soup is a recently permitted facility utilizing SCR, as required by a LAER determination that has been in operation for approximately 3 years. The CEMs data for the SPA Campbell Soup facility supports that the emission rates from the turbine, based on a 3-hour block average, has been approximately 2.5 ppm. As noted before, catalyst degrades with time; so the system may become less efficient as the catalyst ages. As mentioned, the SPA Campbell Soup facility was a LAER determination, however, the difference between BACT and LAER is economic feasibility. The source was requested to do a cost analysis to determine if a 3.0 ppm NO_X limit was economically feasible. The analysis showed that 3.0 ppm NO_X is economically feasible.

<u>Conclusion</u> – Based on the information presented above, the NO_X BACT shall be the use of low NO_X burner design in conjunction with SCR control with an emission limit of 3.0 ppmvd corrected to 15% O_2 based on a 3 hour averaging period, and a duct burner fuel usage limitation equivalent to 1,314 hours per year. The emission limit is equivalent to 18.0 pounds of NO_X per hour for each combustion turbine and 21.1 pounds of NO_X per hour when its associated duct burner is in operation.

During periods of startup and shutdown (less than 50 percent load) the NO_X emission limit for each combustion turbine stack shall not exceed 80 ppmvd corrected to 15% O_2 and 48 ppmvd corrected to 15% O_2, respectively. The startup or shutdown period shall not exceed a period of four (4) hours. Duct burners shall not be operated until normal operation begins.

(3) CO BACT Review

Carbon monoxide emissions from combustion turbines are a result of incomplete combustion of natural gas. Improperly tuned turbines operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor designs and control systems limits the impact of fuel staging on CO emissions.

<u>Control Options Evaluated</u> – The following control options were evaluated in the BACT review:

Thermal Oxidation

Oxidation Catalyst
Good Design/Operation

Discussion – As stated before, CO emissions are a result of incomplete combustion. CO emission can be limited by ensuring complete and efficient combustion of the natural gas in the turbine. Complete combustion is a function of time, temperature and turbulence. Combustion control techniques are used to maximize fuel efficiency and to ensure complete combustion. Many of these controls are inherent in the design of many of the newer natural gas-fired combustion turbines and duct burners.

Thermal Oxidizers

Thermal oxidizers have been widely used as VOC control technology, but using a thermal oxidizer to control CO from a combustion turbine represents operational and maintenance problems. Adding a thermal oxidizer downstream of a turbine is equivalent to adding another combustion chamber where more O_2 is supplied to complete the oxidation of CO. The flue gas is reheated to the temperature at which CO oxidation can take place. This operation would require additional combustion of natural gas thereby increasing NO_X emissions. The RBLC also does not list any entries for the use of this technology with a combustion turbine; therefore, it is eliminated as a technology in the BACT review.

Oxidation Catalyst

Oxidation catalyst uses a precious metal based catalyst to promote the oxidation of CO to CO_2. The oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include catalyst reactor design, optimum operating temperature, backpressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Oxidation catalyst reactors operate in a temperature range of 700 to 900 ^{o}F. At temperatures lower than this range CO conversion to CO_2 reduces rapidly. The catalyst normally placed within the heat recovery steam generator (HRSG) to protect it from catalyst sintering. Cost of an oxidation catalyst can be high with the largest cost associated with the catalyst itself. Catalyst life varies, but typically a 3 to 6 year life can be expected. An oxidation catalyst for the Sugar Creek facility has been determined to be economically infeasible with a cost per ton of CO removed at $5,118 for each gas turbine.

Existing BACT Emission Limitations – The RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents some entries in the RBLC that are similar in size and operation.

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm@15%O_2	Control Description
Proposed Sugar Creek Facility	Turbine (4)	1490.5	9	Good Combustion
	Duct Burner	300	14 (CT+DB)	
Duke Energy New Somyrna Beach, FL	Turbine	500 MW	12	Good Combustion
Auburndale Power Partners, FL	Turbine	1214	15	Good Combustion
Hermiston Generating Co, OR	Turbine (2)	1696	15	Good Combustion

Nerragansett Electric/New England Power, RI	Turbine/ Duct Burner	1360	11	Good Combustion
Portland General Electric, OR	Turbine (2)	1720	15	Good Combustion
Savannah Electric and Power, GA	Turbine	1032	9	Good Combustion
Champion International, ME	Turbine	175 MW	9	Good Combustion
Dighton Power, MA	Turbine	1327	3	Oxidation Catalyst
Berkshire Power, ME	Turbine	1792	4.5	Oxidation Catalyst
Gorham Energy, ME	Turbine	900 MW	5	Oxidation Catalyst

Three of the facilities, Dighton Power, Berkshire Power, and Gorham Energy, used an oxidation catalyst in CO attainment areas. Economic analyses performed on these facilities showed that it was economically feasible to use an oxidation catalyst. A cost analysis for the proposed Sugar Creek facility showed it would cost 5,118 dollars per ton of CO removed. The cost of the projects listed above was around 1,000 to 1,200 dollars per ton of CO removed. The difference in the cost is a result of higher inlet CO emissions. Due to new technological advancements in combustion, turbines are able to achieve a lower inlet CO emission through combustion control techniques. With a resulting lower inlet emission the cost per ton of CO removed increases, making it economically infeasible for CO emission control. Other facilities have been required to use an oxidation catalyst because they were subject to LAER, which does not take into account economics when determining emission control.

Conclusion – Based on the information presented above, the CO BACT shall be the use of natural gas and good design/operation, and a duct burner fuel usage limitation equivalent to 1,314 hours per year. Each combustion turbine shall not exceed 9.0 ppmvd corrected to 15% O_2 on a 24 hour averaging period, which is equivalent to 26.4 pounds per hour. Each combustion turbine, when its associated duct burner is firing shall not exceed 14 ppmvd corrected to 15% O_2, which is equivalent to 51.1 pounds per hour.

During periods of startup and shutdown (less than 50 percent load) the CO emission limit for each combustion turbine stack shall not exceed 150 ppmvd @15% O_2 and 90 ppmvd @15% O_2, respectively. The startup or shutdown period shall not exceed a period of four (4) hours. Duct burners shall not be operated until normal operation begins.

(4) SO_2 BACT Review

Sulfur dioxide (SO_2) emissions are emitted from combustion turbines as a result of the oxidation of the sulfur in the fuel. SO_2 emissions are directly proportional to the sulfur content of the fuel. Emissions from natural gas-fired turbines are low because pipeline quality gas has a low sulfur content (2 grains of sulfur per standard cubic foot of gas). A properly designed and operated turbine utilizing a low sulfur natural gas will have low SO_2 emissions.

Control Options Evaluated – the following control options were evaluated in the BACT review:

Wet Lime Scrubber
Spray Dryer–ESP/Lime Injection-ESP

Discussion – A wet lime scrubber uses a lime solution as a scrubbing medium to control SO_X emissions. Lime scrubbers have been widely used to control SO_X from power plants, however those installed have typically been at coal-fired and other high sulfur oil-fired combustion units. The addition of a wet lime scrubber would require the addition of fuel to control the exit gas stream to eliminate a wet plume effect. Therefore, additional fuel would be required to create a dry plume, thus increasing emissions of other pollutants. In addition, a wet scrubber creates solid waste, which must be dewatered, and then landfilled.

Spray dryer-ESP technology uses a lime slurry which is injected by a spray dryer in the flue gas in the form of fine droplets. The droplets absorb SO_X from the flue gas and then become dry particles due to the evaporation of water. The dry particles are then captured by and ESP downstream of the spray dryer.

The use of low sulfur fuels is the next level of control that was evaluated for the proposed facility. Pipeline quality natural gas has the lowest sulfur content of all the fossil fuels. The NSPS established a maximum allowable SO_2 emission limitation of 150 ppmvd at 15% O_2 or a maximum fuel content of 0.8 percent by weight (40 CFR 60 Subpart GG). Natural gas combustion results in SO_2 emissions at approximately 1 ppmvd. Therefore, the very low SO_2 emission rate that results from the use of natural gas as the sole fuel represents BACT for control of SO_2 emissions from the combustion turbine.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), good combustion practices, and a duct burner fuel usage limitation equivalent to 1,314 hours per year. The SO_X emission limit from each turbine shall be 4.2 pounds SO_2 per hour, and 4.4 pounds SO_2 per hour when its associated duct burner is firing.

(5) VOC BACT Review

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature, and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good combustion practice.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Thermal Oxidation
Catalytic Oxidation
Good Design/Operation

Discussion – Thermal oxidation is a proven technology to control VOC emissions; however, it is rarely used on natural gas-fired sources. The turbines for the proposed facility incorporate state of the art combustion technology and the use of natural gas, which reduce VOC emissions to low concentrations. Because of the low VOC concentration the thermal oxidation technology is ineffective. In addition, thermal oxidation technology requires additional combustion of natural gas, which in turn would generate more emissions. Therefore, thermal oxidation is not considered as BACT for the control of VOC emissions from the proposed facility.

Oxidation catalyst technology utilizes a catalyst to promote the oxidation of CO and unburned hydrocarbon to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion ranges from 950 – 1,050 ^oF. Operation above 1,050 ^oF could cause thermal degradation of the catalyst, and operation below 950 ^oF decreases the catalyst performance.

<u>Existing BACT Emission Limitations</u> – The EPA RBLC is a database system that provides emissions limit data for industrial processes throughout the United States. The table below represents similar operations that have been recently permitted.

Company	Facility	Throughput MMBtu/hr	Emission Limit lb/MMBtu	Control Description
Proposed Sugar Creek Facility	Turbine	1490.5	0.0024	Combustion Control
	Duct Burner	300	0.0028 (CT+DB)	
Gorham Energy, ME	Turbine	2194	0.0017	Oxidation Catalyst
Carolina Power & Light, NC	Turbine	1908	0.0015	Combustion Control
Duke Power Lincoln, NC	Turbine	1247	0.004	Combustion Control
Duke Power Lincoln, NC	Turbine	1313	0.0015	Combustion Control
Alabama Power & Light	Turbine	1777	0.016	Combustion Control
	Duct Burner			
Lakewood Cogeneration, NJ	Turbine	1190	0.0046	Combustion Control
	Duct Burner	131	0.0017	
Auburndale Power Partners	Turbine	1214	0.005	Combustion Control
Berkshire Power Development, MA	Turbine	1792	0.0035	Combustion Control
LSP-Cottage Grove, MN	Turbine	1988	0.008	Combustion Control
	Duct Burner			
Narragansett Electric, RI	Turbine	1360	5 ppm	Combustion Control
	Duct Burner			
Saranac Energy, NY	Turbine	1123	0.0045	Oxidation Catalyst
	Duct Burner	553	0.011	
Southern Energy, MI	Turbine	1000 MW	0.008	Combustion Control
	Duct Burner			
LS Power, IL	Turbine	2166	0.012	Combustion Control
	Duct Burner		0.019	

The RBLC does not list any entries that require an oxidation catalyst for a combined cycle operation reviewed under PSD BACT. Also, an oxidation catalyst would not be economically feasible because of the lower inlet CO emissions associated with new combustion technology. The Duke Power Lincoln and Carolina Power & Light generation plants have VOC emission rates lower than the proposed facility. The difference in emissions is due to different turbine models and site specific conditions. While the VOC emissions are lower for these two facilities their corresponding NOX and CO emissions are higher.

<u>Conclusion</u> – Based on the information presented above, the VOC BACT shall be the use of pipeline quality natural gas, good combustion, and a duct burner fuel usage limitation

equivalent to 1,314 hours per year. The VOC emission limit from each turbine shall not exceed 0.0024 lb/MMBtu on a lower heating value basis, which is equivalent to 3.7. The VOC emission limit from each duct burner shall not exceed 0.005 lb/MMBtu on a higher heating value basis, which is equivalent to 1.6 lb/hr. The VOC emissions from each combustion turbine stack shall not exceed 5.3 lb/hr while operating in combined cycle mode when its associated duct burner is firing.

(B) Auxiliary Boilers

The two auxiliary boilers have a maximum heat input capacity of 35 MMBtu/hr on a higher heating value basis, and will exclusively use natural gas as a fuel. The auxiliary boilers will be limited to 5,000 operating hours per year. The purpose of the auxiliary boilers are to provide heat to the heat recovery steam generator (HRSG) steam drums during shutdown periods to prevent lengthy cold startups reducing the increased emissions associated with startup conditions. The auxiliary boilers will also be used to provide steam for sparging the condensed water used in the HRSG to remove dissolved air and supplying sealing steam to the steam turbines when they are shut down to reduce corrosion and maintain the vacuum on the condensate tank. All of these operations will occur when the HRSG are shut down.

(1) PM BACT Review

There are three potential sources of filterable emissions from combustion sources: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon formed by incomplete combustion of the fuel. There are no sources of mineral matter in the fuel for natural gas-fired combustion sources such as the proposed auxiliary boilers. The potential for soot formation in natural gas-fired combustion turbine is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable particulate originating from the auxiliary boilers.

There are two sources of condensible particulate emissions form combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For natural gas-fired sources such as the auxiliary boilers there should be no condensible organics originating from the source because the main components of natural gas (i.e. methane and ethane) are not condensible at the temperatures found in Method 202 ice bath. As such, any condensed organics are from the ambient air. The most likely condensible particulate matter from natural gas combustion sources is the sulfuric acid dihydrate, which results when the sulfur in the fuel and the ambient air is combusted and then cools.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Cyclone
Fabric Filter (Baghouse)
Electrostatic Precipitator (ESP)
Wet Scrubber

Technically Infeasible Control Options – All control options are basically technically infeasible because the sole fuel for the proposed auxiliary boilers is natural gas, which has little to no ash that would contribute to the formation of PM or PM_{10}. Add-on controls have never been applied to commercial natural gas fired boilers, therefore, add-on particulate matter control equipment is not considered in this BACT review.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database that provides emission limit data for industrial processes throughout the United States. The database for boilers contains many entries, below are some of the entries of the more stringent limitations.

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Sugar Creek Facility	Boiler	35	0.008	lb/MMBtu	Good Design and Operation
Air Liquide America Corp, LA	Boiler	95	0.01	lb/MMBtu	Good Design and operation, use natural gas as fuel
Darling International, CA	Boiler	31.2	0.0137	lb/MMBtu	No control
Kamine/Besicorp Corning L.P., NY	Auxiliary Boiler	33.5	0.0051	lb/MMBtu	Combustion control
Kamine/Besicorp Syracuse L.P., NY	Utility Boiler	33	0.01	lb/MMBtu	Fuel specification
Mid-Georgia Cogeneration	Boiler	60	0.005	lb/MMBtu	Complete Combustion
Newark Bay Cogeneration L.P., NJ	Auxiliary Boiler	200	0.005	lb/MMBtu	Boiler Design
O.H. Kruse Grain and Milling, CA	Backup Boiler	10	0.012	lb/MMBtu	No Control
Solvay Soda Ash Joint Venture Trona Mine/Soda Ash, WY	Boiler	100	5	lb/MMBtu	Minimal Particulate Emissions and Low Emitting Fuel

The PM/PM_{10} emissions from the two (2) 35 MMBtu/hr auxiliary boilers, at the proposed Sugar Creek facility, shall not exceed 0.28 pounds per hour (0.008 lb/MMBtu on a higher heating value basis). The BACT for many of the facility contained in the RBLC is listed as good design and operation, combustion control, and use of natural gas. The PM emission limit is considered achievable with good design and operation; therefore it is considered BACT for particulate matter.

Conclusion – Based on the information presented above the PM/PM_{10} BACT for the auxiliary boilers is good combustion practice, the use of natural gas as its only fuel, and a fuel usage limitation equivalent to 5,000 hours per year. The PM/PM_{10} emissions from the each auxiliary boiler shall not exceed 0.28 pounds per hour (0.008 lb/MMBtu on a higher heating value basis).

(2) NO_X BACT Review

Nitrogen oxide formation during combustion consists of three types, thermal NO_X, prompt NO_X, and fuel NO_X. The principal mechanism of NO_X formation in natural gas combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most NO_X formed through the thermal NO_X is affected by three factors: oxygen concentration, peak temperature, and time of exposure at peak temperature. As these factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level). The second mechanism of NO_X formation, prompt NO_X, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X, reactions occur within the flame and are usually negligible when compared to the amount on NO_X formed through the thermal

NO_X mechanism. The final mechanism of NO_X formation, fuel NO_X, stems from the evolution and reaction of fuel-bonded nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is insignificant.

Control Evaluations Evaluated – The following control options and work practice techniques were evaluated in the BACT review:

Selective Catalytic Reduction (SCR)
Water/Steam Injection
Ultra Low NO_X Burners
Selective Non-Catalytic Reduction (SNCR)
Flue Gas Recirculation (FGR) w/Low NO_X Burners

Technically Infeasible Control Options – Two of the control techniques evaluated are considered to be technically infeasible: water injection and selective catalytic reduction (SCR). Injection of steam or water into the combustion zone can decrease peak flame temperatures, thus reducing thermal NO_X formation. Decreased thermal and fuel efficiencies resulting from steam injection thus increasing fuel usage. The impact on NO_X emissions associated with water/steam injection is an increase in NO_X emissions.

SCR system operates at temperatures between 600 and 800 ^oF, depending on the catalyst. Operating below this temperature range allows significant ammonia (NH_3) slip. According to vendor data, the stack gas temperature of the proposed auxiliary boilers is 366 ^oF. Therefore, a significant amount of reheat will be required to bring the flue gas up to and acceptable temperature range. The additional fuel required to heat the temperature to an acceptable would cause additional NO_X emissions.

Ranking of Technically Feasible Control Options – The following technically feasible nitrogen oxide control technologies were ranked by control efficiency:

Rank	Control	Control Efficiency	Emission Limit
1	Ultra Low NO_X Burners	78%	9 ppmvd
2	Selective Non-Catalytic Reduction (SNCR)	40%	25 ppmvd
3	Flue Gas Recirculation w/Low NO_X Burners	28%	30 ppmvd
4	Low NO_X Burners	Base Case	41.5 ppmvd

Discussion – Ultra Low NO_X Burners are a combustion control which reduces NO_X emissions by rapidly mixing gaseous fuel and combustion air in a region near the burner exit at a stoichiometry that minimizes NO_X. Flue gas recirculation (FGR) is also mixed with the combustion air upstream of the burner which control thermal NO_X. This NO_X control technology is considered to be economically infeasible with a cost per ton of NO_X removed at 12,431 dollars, and is therefore eliminated from this review.

Selective non-catalytic reduction (SNCR) is a post combustion NO_X control technology based on the reaction of NH_3 and NO_X. SNCR involves injection NH_3 into the combustion gas path to reduce the NO_X to nitrogen and water. An important consideration for implementation of SNCR is the operating temperature range. The optimum temperature range is 1,200 to 2,000 ^oF. Operation at temperatures below this range result in significant NH_3 slip; operation above this range results in oxidation of NH_3, forming additional NO_X. The NH_3 also must have sufficient residence time at the optimum operating temperature for efficient NO_X reduction.

FGR recirculates a portion of the flue gas back to the primary combustion zone as a replacement for the combustion air. The recirculated combustion products provide inert gases that lower the adiabatic flame temperature and the overall oxygen concentration in the combustion zone. As a result, FGR controls NO_X emissions by reducing the generation of thermal NO_X.

Existing BACT Emission Limitations – The EPA RACT/BACT/LAER Clearinghouse (RBLC) is a database system that provides emission limit data for industrial processes throughout the United States. The database for boilers was large, containing over 200 entries. The following table represents more stringent emission limitations for similar boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Sugar Creek Facility	Boiler	35	0.048	lb/MMBtu	Low NO_X Burners
Air Liquide America Corp, LA	Boiler	95	0.05	lb/MMBtu	Good Design and operation, use natural gas as fuel
Darling International, CA	Boiler	31.2	0.036	lb/MMBtu	Low NO_X Burner w/FGR
Huls America, AL	Boiler	38.9	0.075	lb/MMBtu	Low NO_X Burners
I/N Kote, IN	Boiler	70.8	0.05	lb/MMBtu	Fuel Spec. and FGR
Kamine/Besicorp Corning, NY	Boilers	33.5	0.32	lb/MMBtu	Low NO_X Burners
Kamine/Beiscorp, NY	Boilers	33	0.035	lb/MMBtu	FGR
Mid-Georgia Cogen., GA	Boiler	60	0.1	lb/MMBtu	Low NO_X Burner w/FGR
O.H. Kruse Grain and Milling, CA	Boiler	10	0.106	lb/MMBtu	No Control
Shell Offshore, Inc., LA	Boiler	48.2	0.1	lb/MMBtu	Low NO_X Burner
Sunland Refinery, CA	Boiler	12.6	0.36	lb/MMBtu	Fuel Spec. and Low NO_X Burners
Toyota Motor Corp, IN	Boiler	58	0.1	lb/MMBtu	Low NO_X Burner

Based on the RBLC review, there are two facilities, with similar heat input capacity, that have been permitted with a lower NO_X emission limitation than the proposed Sugar Creek facility. The Darling International facility utilizes Low NO_X burners along with flue gas recirculation to achieve lower limits than the proposed Mirant Sugar Creek facility. This facility is located in a nonattainment area, therefore LAER was applied. A flue gas recirculation was evaluated for the proposed Sugar Creek facility, and it was determined to be economically infeasible with a cost per ton of NO_X removed at $21,581. The other facility that utilizes a flue gas recirculation system to obtain a lower limit that the proposed Sugar Creek facility is the Kamine/Beiscorp Corporation site in New York. The boiler at this facility is of similar size, however, it does not employ low NO_X burners. As a result, there is a higher NO_X exhaust concentration, making flue gas recirculation system economically feasible. There are several larger boilers that have been permitted with a flue gas recirculation system, however, a larger boiler will have a higher NO_X emission rate, therefore making a flue gas recirculation system economically feasible.

Conclusion – Based on the information presented above, the NO_X BACT for the auxiliary boilers shall be the use of Low NO_X burner design in conjunction with a fuel specification of natural gas only, and a fuel usage limitation equivalent to 5,000 annual hours of operation. The emission limit of NO_X will be 41.5 ppmvd (0.048 lb/MMBtu on a higher heating value basis) based on a 30 day rolling average.

(3) SO_2 BACT Review

Emissions from natural gas-fired boilers are low because pipeline quality gas has a low sulfur content. A properly designed and operated boiler utilizing low sulfur natural gas.

Control Options Evaluated – the following control options were evaluated in the BACT review:

Wet Lime Scrubber
Spray Dryer–ESP/Lime Injection-ESP

Discussion – A wet lime scrubber uses a lime solution as a scrubbing medium to control SO_X emissions. Lime scrubbers have been widely used to control SO_X from power plants, however those installed have typically been at coal-fired and other high sulfur oil-fired combustion units. The addition of a wet lime scrubber would require the addition of fuel to control the exit gas stream to eliminate a wet plume effect. Therefore, additional fuel would be required to create a dry plume, thus increasing emissions of other pollutants. In addition, a wet scrubber creates solid waste, which must be dewatered, and landfilled.

Spray dryer-ESP technology uses a lime slurry which is injected by a spray dryer in the flue gas in the form of fine droplets. The droplets absorb SO_X from the flue gas and then become dry particles due to the evaporation of water. The dry particles are then captured by and ESP downstream of the spray dryer.

The use of low sulfur fuels was the next level of control that was evaluated for the proposed facility. Pipeline quality natural gas has the lowest sulfur content of all the fossil fuels. The NSPS established a maximum allowable SO_2 emission associated with combustion turbines and requires either an SO_2 emission limitation of 150 ppmvd at 15 percent oxygen or a maximum fuel content of 0.8 percent by weight (40 CF 60 Subpart GG). Therefore, the very low SO_2 emission rate that results from the use of natural gas as the sole fuel represents BACT for control of SO_2 emissions from the auxiliary boiler.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), good combustion practices, and a fuel usage limitation equivalent to 5,000 annual operating hours. The SO_X emission limit from each boiler shall be 0.02 lb/hr.

(4) CO BACT Review

Carbon monoxide emissions from boilers are a result of incomplete combustion of natural gas. Improperly tuned boilers operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

Control Options Evaluated – The following control options and work practice techniques were evaluated in the BACT review:

Thermal Oxidation
Catalytic Oxidation

Good Design/Operation

Discussion – Thermal oxidizers are designed so that the combustion of gases from the boiler pass through another combustion device where CO is reduced to CO_2 at temperatures of 1,200 to 2,000 ^oF. Thermal oxidizer use on a natural gas combustion source is rare. Overall emissions, NO_X, would increase due to additional fuel combustion, higher operating temperatures, and excess air introduced to the system.

Catalytic oxidizers are designed so that the combustion from the boiler pass through a flame area and then through a catalyst bed where CO is reduced to CO_2 at temperatures ranging from 650 to 1000 ^oF. The catalyst bed reduces the temperature at which the CO is reduced to CO_2 but does not remove the need of reheating the exit gases prior to the catalyst bed for boilers. Overall combustion emissions would increase due to additional fuel combustion in the oxidizer flame.

Existing BACT Emission Limitations – The EPA RBCL provides a emission limit data for industrial processes throughout the United States. The following table represents the more stringent BACT emission limitations established for boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Sugar Creek Facility	Boiler	35	2.9	lb/hr	Good Design and Operation
Mid-Georgia Cogen., GA	Boiler	60	3	lb/hr	Complete Combustion
Darling International, CA	Boiler	31.2	2.8	lb/hr	Good Combustion
Indelk Energy, MI	Boiler	99	14.85	lb/hr	Combustion Control
Kamine/Besicorp, NY	Boiler	33	1.26	lb/hr	No controls
Champion International, AL	Boiler	5.8	0.522	lb/hr	Good Combustion Practice
Stafford Railsteel Corp., AR	Boiler	46.5	0.7	lb/hr	Fuel Spec.
Quincy Soybean Co., AR	Boiler	68	10.6	lb/hr	Good Combustion Practices

Many of the entries in the RBCL database list control of CO emissions from natural gas fired boilers to be good combustion practices, fuel specification, and complete combustion. Burner manufactures control CO emissions by maintaining various operational combustion parameters. Fuel conditions, draft and changes in air can be adjusted to insure good combustion. The proposed CO emission limit for the Sugar Creek facility is 2.9 lb/hr. This limit is one of the more stringent CO limitations listed in the RBLC for similar sized boilers. The entries in the above table that are lower than the proposed limit are based on LAER, and therefore, cannot be directly compared to the proposed Sugar Creek project.

Conclusion – Based on the information presented above, the CO BACT shall be the use of low sulfur natural gas (less than 0.8% by weight) and good combustion practice, and a fuel usage limitation equivalent to 5,000 hours per year. Each auxiliary boiler shall not exceed 2.9 lb/hr CO.

(5) VOC BACT Review

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good controls.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Thermal Oxidation
Catalytic Oxidation
Good Design/Operation

Discussion – Thermal oxidation is a proven technology to control VOC emissions, however it is rarely used on natural gas-fired sources. Because of the low VOC concentration generated from the use of natural gas and good combustion practice, the thermal oxidation technology is ineffective. In addition, the thermal oxidation technology requires additional combustion of natural gas, which in turn would generate more emissions.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbon to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion ranges from 650 to 1,000 oF. In addition the use of a oxidation catalysts would require additional combustion of natural gas, which increase NO_X and CO emissions.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed Sugar Creek Facility	Boiler	35	0.2	lb/hr	Good Design and Operation
Mid-Georgian Cogen., GA	Boiler	60	0.3	lb/hr	Complete Combustion
Stafford Railsteel Corp., AR	Boiler	46.5	0.8	TPY	Fuel Spec. Natural Gas
Waupaca Foundry, IN	Boiler	93.9	0.55	lb/hr	Good Combustion Practice
Weyerhaeuser Co., MS	Boiler	400	0.52	lb/hr	Efficient Operation
Willamette Industries, LA	Boiler	335	1.0	lb/hr	Design and Operation
Kamine/Besicorp, NY	Boiler	2.5	0.01	lb/hr	No controls
Transamerica Refining Corp., LA	Boiler	1.2	0.01	lb/hr	Good Combustion Practices

Many of the entries in the RBLC list good combustion, fuel specification, and good design and operation as BACT for VOC emission control. For boilers with similar heat input capacities as the proposed, a VOC emission limit of 0.2 lb/hr, is one of the lowest emission rates. The Kamine/Besicorp and Transamerica Refining Corporation have the lowest emission rates; however, both of these boilers are considerably smaller than the proposed Sugar Creek auxiliary boilers.

Conclusion – Based on the information presented above, the VOC BACT for each auxiliary boiler at the proposed Sugar Creek facility shall be good design and operation, and a fuel usage limitation equivalent to 5,000 hours per year. Each boiler shall be limited to 0.02 lb/hr VOC.

(C) Cooling Tower

Evaporative cooling towers are designed to cool process cooling water by contacting the water with air, and evaporating some of the water. Thus, these units use the latent heat of water vaporization to exchange heat between the process air and the air passing through the tower. This type of cooling tower typically contains a wetter medium to promote evaporation, by providing a large surface area and/or by creating many water drops with a large cumulative surface area. Some of the liquid water may be entrained in the air stream and be carried out of the tower.

(1) PM BACT Review

Emissions of particulate matter from cooling towers are designed to cool process cooling water by contacting the water with air, and evaporating some of the water. Thus, these units use the latent heat of the water vaporization to exchange heat between the process air and the air passing through the tower. This type of cooling tower typically contains a wetted medium to promote evaporation, by providing a large surface area and/or by creating many water drops with a large cumulative surface area. Some of the liquid water may be entrained in the air stream and me carried out of the tower, referred to as drift.

Control Options Evaluated

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Good Design/Operation

Technically Infeasible Control Options – A baghouse is technically infeasible because the level of moisture in the cooling tower exit gas stream would cause the bags to cake and not allow proper air flow through the system. In addition, there are no instances where a baghouse is used as BACT for particulate matter control of a cooling tower.

An electrostatic precipitator (ESP) is an effective control for particulate matter; however, there are no instances where an ESP is used for PM control associated with a cooling tower. Also, the economic feasibility of using and ESP for PM control is to high at 1,434,020 dollars per ton of PM removed.

Existing BACT Emission Limitations – The EPA is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for cooling towers:

Company	Facility	Control	Total Liquid Drift (% flow)	PM/PM_{10} BACT Limitations (lb/hr)	Compliance Status

Proposed Sugar Creek Power Facility	Cooling Tower	Drift Eliminator	0.001	1.41	N/A
Crown/Vista Energy, NJ	Cooling Tower	Drift Eliminator	0.1	5.9	None Required
Texaco Bakersfield	Cooling Tower	Cellular Type Drift Eliminator	---	1.26	None Required
Ecoelectrica LP, PR	Cooling Tower	2-Stage Drift Eliminator	0.0015	60	None Required
Lakewood Cogen, NJ	Cooling Tower	Drift Eliminator	0.002	0.874	None Required
Crystal River, Units 1,2,3, FL	Cooling Tower	High Eff. Drift Eliminator	0.004	428	None Required
Crystal River, Units 4,5, FL	Cooling Tower	High Eff. Drift Eliminator	---	175	None Required

Emissions of particulate matter from cooling towers are created when water droplets escaping the tower evaporate, and the dissolved and suspended solids within these droplets become airborne. The concentration of total dissolved solids (TDS) in different cooling water varies widely and is site dependent. For the proposed Sugar Creek facility, the water is noncontact cooling water, so the amount of TDS is not a result of the cooling process.

For a given solids concentration (defined by the cooling water source, tower design and operating specifications), particulate matter emissions from cooling towers depend on the amount of water that drifts from the tower. The amount of drift from evaporative cooling towers, usually expressed as a percent of circulating water flow, is called liquid drift. Total liquid drift is controlled by drift eliminators, which are installed in the tower cells. A drift eliminator passes the cooling tower exhaust through mesh type media resulting in the separation of water droplets from the air stream.

The above table shows a search of available cooling tower permit information revealed different types of cooling towers that are permitted, including mechanical draft, wet/dry and hyperbolic towers.

Conclusion – Based on the information presented, the PM BACT shall be to use high efficiency drift eliminators on each cooling tower cell. The total liquid drift rate shall not exceed 0.001 percent. The total particulate emissions from the cooling towers shall not exceed 1.41 pounds per hour.