NEW SOURCE CONSTRUCTION PERMIT
Prevention of Significant Deterioration (PSD) Permit
Office of Air Quality

Cogentrix Lawrence County, LLC
Rural Route 3
Mitchell, IN 47446

(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 093-12432-00021	
Issued by: Original Signed by Paul Dubenetzkey Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: October 5, 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). 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 combined cycle electric power generating facility.

Authorized Individual:	Mark A. Casper
Source Address:	Rural Route 3, Mitchell IN 47446
Mailing Address:	9405 Arrowpoint Boulevard, Charlotte, NC 28273-8110
Phone Number:	(704) 525-3800
SIC Code:	4911
County Location:	Lawrence
County Status:	Attainment for all criteria pollutants
Source Status:	Major, under PSD rules One of the 28 listed Categories (Fossil Fuel-Fired Electric Generating Plant of more than 250 MMBtu/hr)

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) Three (3) natural gas-fired combustion turbine generators, designated as units CTG01, CTG02, and CTG03 with a maximum heat input capacity of 1,944.1 MMBtu/hr (per unit), and exhausts to stacks designated as CTG01, CTG02, and CTG03 respectively.

(b) Three (3) heat recovery steam generators designated as unit HRSG1, HRSG2, and HRSG3, with three (3) associated duct burners, with a maximum heat input capacity of 300 MMBtu/hr (per unit).

(c) Three (3) selective catalytic reduction systems, designated as units SCR1, SCR2, and SCR3

(d) Three (3) cooling towers, designated as CT01, CT02, and CT03 and exhausts to stacks designated as CT01, CT02, and CT03.

(e) One (1) natural gas fired auxiliary boiler, designated as unit SUB with a maximum heat input rating of 35 MMBtu/hr, and exhausts to stack designated as SUB.

(f) One (1) standby generator (DGS) utilizing low sulfur diesel fuel, with a maximum heat input capacity of 8.40 MMBtu/hr and exhausts to stack designated as DGS.

(g) One (1) backup fire pump (DFP) utilizing low sulfur diesel fuel, with a maximum rated heat input capacity of 2.0 MMBtu/hr and exhausts to stack designated as DFP.

(h) Three (3) natural gas fuel pre-heaters, designated as GH01, GH02, and GH03 with a maximum heat input rating of 5.0 MMBtu/hr each.

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 turbine generators 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, the effective date of this permit will be thirty (30) days after the service of notice of the decision, except as provided in 40 CFR 124. Three (3) days shall be added to the thirty (30) day period 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), 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.

   (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.

   (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 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

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 Status [326 IAC 2-2] [326 IAC 2-7]

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) or position(s) responsible for inspecting, maintaining, and repairing emission control devices;

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

(2) 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 upon request and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ 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

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, 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, 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 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

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 must receive all test reports within forty-five (45) days after the completion of the testing. IDEM, OAQ 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 upon request and shall be subject to review and approval by IDEM, OAQ. 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 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 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 within thirty (30) days of receipt of the notice of deficiency. IDEM, OAQ 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 that retesting in one hundred and twenty (120) days is not practicable, IDEM, OAQ 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 Emergency Reduction Plans [326 IAC 1-5-2 and 326 IAC 1-5-3]

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.

C.17 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 malfunctions during 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), 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, 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.18 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 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.19 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 representative. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a written request for records to the Permittee, the Permittee shall furnish the records to the Commissioner 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.20 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

(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 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 do not 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 – Combined Cycle Operation

(a) Three (3) natural gas-fired combustion turbine generators, designated as units CTG01, CTG02, and CTG03, with a maximum heat input capacity of 1,944.1 MMBtu/hr (per unit) on a higher heating value basis, and exhausts to stacks designated as CTG01, CTG02, and CTG03, respectively.

(b) Three (3) heat recovery steam generators, designated as units HRSG1, HRSG2, and HRSG3 with three (3) associated duct burners, with a maximum heat input rating of 300 MMBtu/hr (per unit).

(c) Three (3) selective catalytic reduction systems, designated as units SCR1, SCR2, and SCR3

(d) Three (3) cooling towers, designated as units CT01, CT02, and CT03 exhausts to stacks designated CT01, CT02, and CT03

(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/PM_{10}) Emission Limitations for Combustion Turbines/Duct Burners

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM which 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 0.014 pounds per MMBtu on a higher heating value basis, and 24.0 pounds per hour for each combustion turbine and associated duct burner.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM which is the sum of PM (filterable) and PM_{10} (filterable and condensible) emissions from each combustion turbine when its associated duct burner is not operating, shall not exceed 0.017 pounds per MMBtu on a higher heating value basis, and 20.0 pounds per hour for each combustion turbine without duct burners.

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 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 3.43 pounds per hour; the total liquid drift rate shall not exceed 0.002%

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

(3) Drift eliminators shall be used as a control, and operating at all times

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

D.1.5 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 period shall not exceed 250 minutes, and each shutdown period shall not exceed two (2) hours. Each turbine shall not exceed 1670 hours per year for startups and 800 hours per year for shutdowns.

(b) The NO_X emissions from each combustion turbine stack shall not exceed 275 pounds per startup and 35.0 pounds per shutdown.

(c) The CO emissions from each combustion turbine stack shall not exceed 1173.75 pounds per startup and 336 pounds per shutdown.

D.1.6 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines/Duct Burners

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

(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) operating hour rolling averaging period, which is equivalent to 25.9 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) operating hour rolling averaging period, which is equivalent to 29.7 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.

(b) Use natural gas as the only fuel.

D.1.7 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:

(1) During normal combined cycle operation (fifty (50) percent load or more), the CO emissions from each combustion turbine shall not exceed 6.0 ppmvd corrected to fifteen (15) percent Oxygen on a 24 operating hour rolling averaging period, and 23.4 pounds per hour for each combustion turbine.

(2) During normal combined cycle operation (fifty (50) percent load or more), the CO emissions from each combustion turbine when its associated duct burner is operating shall not exceed 9.0 ppmvd corrected to fifteen (15) percent oxygen on a 24 operating hour rolling averaging period, and 48.1 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.

(b) Use natural gas as the only fuel

D.1.8 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:

(1) During normal combined cycle operation (fifty (50) percent load or more), the SO_2 emissions from each combustion turbine shall not exceed 0.006 pounds per MMBtu on a higher heating value basis, and 11.7 pounds per hour for each combustion turbine.

(2) During normal combined cycle operation (fifty (50) percent load or more), the SO_2 emissions from each combustion turbine stack, when its associated duct burner is operating, shall not exceed 0.006 pounds per MMBtu on a higher heating value basis, and 13.2 pounds per hour for each combustion turbine and duct burner

(3) Perform good combustion practice.

D.1.9 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:

(1) The VOC emissions from each combustion turbine shall not exceed 0.0020 pounds per MMBtu on a higher heating value basis, and 3.6 pounds VOC per hour for each combustion turbine.

(2) The VOC emissions from each combustion turbine, when its associated duct burner is

operating, shall not exceed 0.0037 pounds per MMBtu on a higher heating value basis, and 7.6 pounds VOC per hour for each combustion turbine.

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

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

D.1.10 40 CFR 60, Subpart GG (Stationary Gas Turbines)

The three (3) 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.

D.1.11 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 form 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.1.2 constitutes compliance with this condition.

(c) Each duct burner shall not exceed 0.2 lb/MMBtu 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.1.8 constitutes compliance with this condition.

D.1.12 Formaldehyde Limitations [326 IAC 2-1.1-5] [326 IAC 2-4.1]

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the formaldehyde emissions from each combustion turbine and duct burner shall not exceed 0.000275 pounds of formaldehyde per MMBtu.

D.1.13 Ammonia Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements),

(a) the ammonia emissions from each combustion turbine stack shall not exceed ten (10) ppmvd corrected to 15% O_2.

(b) annual ammonia emissions shall not exceed 446.8 tons per year.

D.1.14 Natural Gas Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements), the combined natural gas fuel usage from each of the duct burners shall not exceed 2,575 MMSCF per year, based on a twelve (12) consecutive month period.

D.1.15 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.1.16 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 (CTG01, CTG02, and CTG03) 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 (CTG01, CTG02, and CTG03) utilizing a method approved by the Commissioner when operating at 70%, 85%, 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.1.12.

(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 (CTG01, CTG02, and CTG03) 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.1.5.

(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 (CTG01, CTG02, and CTG03) when operating at 100% load 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.1.10.

(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 (filterable), PM_{10} (filterable and condensible), ammonia, and VOC stack tests for each combustion turbine stack (CTG01, CTG02, and CTG03) when operating at 100% load utilizing methods approved by the Commissioner. These tests shall be performed in accordance with Section C – Performance Testing, in order to document compliance with D.1.13.

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

D.1.17 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.1.18 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 CTG01, CTG02 and CTG03 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 (ppm) at 15% O_2 over a three (3) operating hour rolling averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) 15% O_2 over a twenty four (24) operating hour rolling 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.1.5 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.1.19 Record Keeping Requirements

(a) To document compliance with Conditions D.1.2, D.1.5 through D.1.8, 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) 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.1.5, 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 operating hour rolling 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.1.6 and D.1.7, 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.1.18, 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.1.10, the Permittee shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of five (5) years.

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

D.1.20 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.1.6, and D.1.7 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 to document compliance with Condition D.1.5, 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.2 FACILITY CONDITIONS – Auxiliary Boiler

(e) One (1) natural gas fired auxiliary boiler, designated a unit SUB, with a maximum heat input capacity of 35 MMBtu/hr per unit, on a higher heating value basis, and exhausts to a stack designated as SUB.

(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 Emissions (PM/PM_{10}) for Auxiliary Boiler

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

(a) PM emissions from the auxiliary boiler shall not exceed 0.02 lb/MMBtu on a higher heating value basis, which is equivalent to 0.70 pounds per hour.

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

(c) Perform good combustion practices

D.2.3 Opacity Limitations [326 IAC 2-2]

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.2.4 Nitrogen Oxide (NO_X) Emission Limitations for Auxiliary Boiler

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

(a) NOx emissions from the auxiliary boiler shall not exceed 0.08 lb/MMBtu on a higher heating value basis, which is equivalent to 2.80 pounds per hour for each auxiliary boiler.

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

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

D.2.5 Carbon Monoxide (CO) Emission Limitations for Auxiliary Boiler

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

(a) CO emissions from the auxiliary boiler shall not exceed 0.082 lb/MMBtu on a higher heating value basis, which is equivalent to 2.87 pounds per hour.

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

(c) Operate utilizing good combustion practices.

D.2.6 Sulfur Dioxide (SO_2) Emission Limitations for Auxiliary Boiler

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

(a) SO_2 emissions from the auxiliary boiler shall not exceed 0.006 lb/MMBtu on a higher heating value basis, which is equivalent to 0.21 pounds per hour.

(b) Operate utilizing good combustion practices.

D.2.7 Volatile Organic Compound (VOC) Emission Limitations for Auxiliary Boiler

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

(a) VOC emissions from the auxiliary boiler shall not exceed 0.011 lb/MMBtu on a higher heating value basis, which is equivalent to 0.39 pounds per hour.

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

(c) Operate using good combustion practices.

D.2.8 Natural Gas Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements), the natural gas usage of the auxiliary boiler shall not exceed 102.9 MMSCF per year, based on a twelve (12) consecutive month period.

D.2.9 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.2.10 Performance Testing

(a) For compliance purposes the 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.

(b) IDEM, OAQ 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.2.11 Record Keeping Requirements

(a) To document compliance with Conditions D.2.8, the Permittee shall maintain records of the amount of natural gas combusted for the auxiliary boiler during each month.

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

D.2.12 Reporting Requirements

The Permittee shall submit the following information on a quarterly basis. A summary of the information to document compliance with Condition D.2.8 and D.2.11 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.3 FACILITY CONDITIONS – Backup Equipment

(f) One (1) standby diesel generator designated as DGS, utilizing low sulfur fuel, with a maximum heat input capacity of 8.40 MMBtu/hr and exhausts to a stack designated as DGS.

(g) One (1) backup fire pump designated as DFP, utilizing low sulfur diesel fuel, with a maximum rated heating capacity of 2.0 MMBtu/hr and exhausts to a stack designated as DFP.

(h) Three (3) natural gas fuel pre-heaters, designated as GH01, GH02, and GH03 with a maximum heat input rating of 5.0 MMBtu/hr each.

(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 BACT Limitation for Fire Pumps

Pursuant to 326 IAC 2-2 (PSD Requirements) the one (1) diesel fire pump shall comply with the following:

(a) The fuel input of the fire pump shall be limited to 7,299 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.3.2 BACT Limitation for Emergency Generator

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

(a) The fuel input of the emergency generator shall be limited to 30,657 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.3.3 BACT Limitation for Fuel Preheaters

Pursuant to 326 IAC 2-2 (PSD Requirements) the three (3) fuel preheaters shall comply with the following:

(a) The fuel input of each of the Three (3) fuel preheaters shall be limited to 42.94 MMCF per year, based on a twelve (12) consecutive month period.

(b) Use very low sulfur natural gas.

(c) Perform good combustion practice.

Compliance Determination Requirements

D.3.4 Testing Requirements [326 IAC 2-1.1-11]

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, 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.3.5 Record Keeping Requirements

To document compliance with Conditions D.3.1, D.3.2, and D.3.3 the Permittee shall maintain records of the following:

(1) Amount of diesel fuel combusted each month in the one (1) fire pump.

(2) Amount of diesel fuel combusted each month in the one (1) emergency generator.

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

D.3.6 Reporting Requirements

A quarterly summary of the information to document compliance with D.3.1, D.3.2, and D.3.3 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.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION

CONSTRUCTION PERMIT
ANNUAL NOTIFICATION

This form should be used to comply with the notification requirements under 326 IAC 2-6.1-5(a)(5).

Company Name:	Cogentrix Lawrence County, LLC
Address:	Rural Route 3
City:	Mitchell, IN 47446
Phone #:	To be provided later
MSOP #:	093-12432-00021

I hereby certify that Cogentrix Lawrence Co. LLC is still in operation.
no longer in operation.

I hereby certify that Cogentrix Lawrence Co. LLC is in compliance with the requirements of MSOP 167-12208-00123.
not in compliance with the requirements of MSOP 167-12208-00123.

Authorized Individual (typed):
Title:
Signature:
Date:

If there are any conditions or requirements for which the source is not in compliance, provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be achieved.

Noncompliance:

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.

***<u>Essential services</u>** 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

Quarterly Report

Company Name: Cogentrix Lawrence County, LLC
Location: Rural Route 3, Micthell, In 46446
Permit No.: CP-093-12432-00021
Source: Three (3) Duct Burners
Limit: 2,575 MMSCF of natural gas per twelve (12) consecutive month period

Year: ____________

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

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

Quarterly Report

Company Name: Cogentric Lawrence County, LLC
Location: Rural Route 3, Mitchell, In 47446
Permit No.: CP-093-12432-00021
Source: One (1) Auxiliary Boiler
Limit: 102.9 MMSCF of natural gas per twelve (12) consecutive month period

Year: ____________

Month	Usage (MMSCF/month)	Usage for previous month(s) (MSMCF)	Usage for twelve month period (MMSCF)

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

Quarterly Report

Company Name: Cogentrix Lawrence County, LLC
Location: Rural Route 3, Mitchell, IN 47446
Permit No.: CP-093-12432-00021
Source: One (1) emergency diesel fire pump
Limit: 7,299 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

Quarterly Report

Company Name:	Cogentrix Lawrence County, LLC
Location:	Rural Route 3, Mitchell, In 47446
Permit No.:	CP-093-12432-00021
Source:	One (1) emergency diesel generator
Limit:	30,657 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

Quarterly Report

Company Name: Cogentrix Lawrence County, LLC
Location: Rural Route 3, Micthell, In 46446
Permit No.: CP-093-12432-00021
Source: Three (3) Fuel Preheaters
Limit: 42.94 MMSCF per twelve (12) consecutive month period

Year: ____________

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

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

Quarterly Report

Company Name: Cogentrix Lawrence County, LLC
Location: Rural Route 3, Mitchell, In 47446
Permit No.: CP-093-12432-00021
Source: Three (3) natural gas combustion turbines operating in combined cycle
Limit: Four (4) hours per startup, and 1670 hours per year for startups. Two (2) hours per shutdown, and 800 hours per year for shutdowns.

Month: ________________ Year: ______________

Day/Turbine#	1	2	3	4	Day/Turbine#	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					no. of deviations				

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

Addendum to the
Technical Support Document for New Construction and P.S.D. Operation

Source Name:	Cogentrix Lawrence County, LLC
Source Location:	Rural Route 3, Mitchell, IN 47446
County:	Lawrence
Construction Permit No.:	CP-093-12432-00021
SIC Code:	4911
Permit Reviewer:	Mack E. Sims

On May 11, 2001, the Office of Air Quality (OAQ) had a notice published in The Times-Mail located in Bedford, Indiana, stating that Cogentrix Lawrence County, LLC, had applied for a Prevention of Significant Deterioration (PSD) permit for the construction of an 820 MW natural gas fired combined cycle merchant electric generating station consisting of three combustion turbines, each with a nominal heat input rate of 1944.1 MMBtu per hour (HHV) @ ISO conditions, and three heat recovery steam generators with three duct burners with a nominal heat input rate of 300 MMBtu per hour (HHV) @ ISO conditions, each. The detailed description of equipment can be found in the Prevention of Significant Deterioration construction permit.

The notice also stated that OAQ proposed to issue a permit for this installation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

During the public comment period and at the public hearing, held on June 11th, the source and several concerned citizens submitted similar comments on the proposed construction permit. Concerned citizens providing comments at the hearing included Mr. Ned Barretto, Mr. Larry Sipes, and Mr. David Rhum. Written comments were provided by Cogentrix LLC, Mr. Stephen Loeschner, combined comments from the Hoosier Environmental Council (HEC), Citizens Action Coalition of Indiana (CACI) and Mr. Stephen Loeschner, Mr. Larry Sipes, Mr. Andrew J. Sobiech and Berger and Berger and Dr. Phyllis J. Fox representing the South Central Indiana Building and Construction Trades Council. Due to the numerous comments submitted by the public and the overlap of issues raised by many commentors, the IDEM, OAQ will summarize all the issues raised by the general public. Specific comments attributable to individuals will be noted when those comments submitted by them are significantly different than those addressed by other commentors. The IDEM, OAQ's responses carefully considered all related comments raising similar issues on the identified topics.

Upon further review, the OAQ has decided to make the following revisions and clarifications to the permit (bolded language has been added, the language with the strikethrough has been deleted):

1. Subsequent to public notice of this proposed PSD permit another combined cycle facility in Illinois was issued a PSD permit with a CO emission limit of 4 ppmvd (ppm) @ 15% oxygen without duct firing (unfired) and 9 ppm @ 15% oxygen with duct firing (fired), utilizing good combustion as control. The 9 ppm fired CO limit is for the first two years of operation with a decrease to 6 ppm thereafter. However, the 9 ppm may be extended for another two years if there is not enough data to support reliably achieving the 6 ppm level. The OAQ reevaluated BACT for CO and has lowered the emission limits. The OAQ has determined that 6 ppm (unfired) and 9 ppm (fired) at 15% oxygen to be appropriate limits. OAQ acknowledges that these turbines may be able to achieve 4 ppm without a control device when new, but there is no long term data to support or contradict this point. OAQ therefore believes that it's CO BACT limit of 6 ppm (unfired) and 9 ppm (fired) represents BACT in this case. The Illinois permit has the lower CO limit of 4 ppm, however it also has a higher NO_X limit of 4.5 ppm @15% oxygen than the proposed Cogentrix Lawrence County facility. In addition, the Illinois permit allows the source to petition for removal of the continuous emission monitoring system (CEMS) after 2 years of compliance. The proposed Cogentrix Lawrence County permit does not allow removal of CEMS. As the turbine ages CO levels may increase, therefore, by not allowing removal of CEMS continued compliance with the established CO emission limit will be ensured. Given the regional air quality conditions and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, the proposed emission limits are believed to be protective of health and the environment and provides equity among the sources being permitted by OAQ.

   Condition D.1.7 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines/Duct Burners has been changed as follows:

D.1.7 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:

   (1) During normal combined cycle operation (seventy (70) percent load or more), the CO emissions from each combustion turbine shall not exceed ~~9.0~~ **6.0** ppmvd corrected to fifteen (15) percent Oxygen on a 24 hour averaging period, and ~~35.1~~ **23.4** pounds per hour for each combustion turbine.

   (2) During normal combined cycle operation (seventy (70) percent load or more), the CO emissions from each combustion turbine when its associated duct burner is operating shall not exceed ~~12.2~~ **9.0** ppmvd corrected to fifteen (15) percent oxygen on a 24 hour averaging period, and ~~62.0~~ **48.1** 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.

(b) Use natural gas as the only fuel

OAQ makes the following additional changes to the permit for consistency, correctness and clarification.

The Table of Contents is changed as follows:

Condition C.1 is changed as follows:

C.1 Major Source **Status [326 IAC 2-2] [326 IAC 2-7]**

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.

The following conditions were both numbered C.16:

C.16 Emergency Reduction Plans [326 IAC 1-5-2 and 326 IAC 1-5-3]

and

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

The OAQ is renumbering the second condition shown above and all remaining conditions in Section C will be renumbered accordingly as follows:

C.~~16~~**17** Malfunctions Report [326 IAC 1-6-2]

C.~~17~~**18** Monitoring Data Availability [326 IAC 2-6.1-2] [IC 13-14-1-13]

C.~~18~~**19** General Record Keeping Requirements [326 IAC 2-6.1-2]

C.~~19~~**20** General Reporting Requirements [326 IAC 2-1.1-11] [326 IAC 2-6.1-2] [IC 13-14-1-13]

Condition D.1.11 is changed as follows:

D.1.11 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 form 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.1.2 constitutes compliance with this condition.~~

(c) Each duct burner shall not exceed 0.2 lb/MMBtu 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.1.8 constitutes compliance with this condition~~.

Condition D.1.16 is changed as follows to allow for a better spread between test points and to clarify required testing:

D.1.16 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 (CTG01, CTG02, and CTG03) 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 (CTG01, CTG02, and CTG03) utilizing a method approved by the Commissioner when operating at 70%, ~~75%,~~ **85%,** 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.1.12.

(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 (CTG01, CTG02, and CTG03) 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.1.5.

(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 (CTG01, CTG02, and CTG03) **when operating at 100% load** 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.1.10.

(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 **(filterable)**, PM_{10} (filterable and condensible), ammonia, and VOC stack tests for each combustion turbine stack (CTG01, CTG02, and CTG03) **when operating at 100% load** 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.1.2(b), D.1.9, and~~ D.1.13.

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

The twenty percent (20%) opacity required in Condition D.2.3 is a BACT condition. The PSD rule cite is added to the condition as follows:

D.2.3 Opacity Limitations **[326 IAC 2-2]**

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.

On June 19, 2001 Cogentrix Lawrence County LLC submitted comments on the proposed construction and operating permit. The summary of the comments and corresponding responses are as follows (changes are emphasized through bold and strikethrough text)

Comment 1: Condition A.2
A.2(a) – The stack designations in this paragraph should be “CTG01, CTG02 and CTG03” and not “CT01, CT02, CT03.”
A.2(d) – The cooling towers do not exhaust to the turbine stack. The paragraph should read. “Three (3) cooling towers, designated as CT01, CT02 and CT03.”
A.2(h) – The paragraph should end with the word “each”.

Response 1: Condition A.2 is revised as follows to reflect the unit, stack designations and heat inputs contained in the permit application. No change was made to condition A.2(d) as the cooling tower unit and stack designations reflect what is in the permit application.

A.2 Emissions ~~u~~**U**nits and Pollution Control Equipment Summary

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

(a) Three (3) natural gas-fired combustion turbine generators, designated as units CTG01, CTG02, and CTG03 with a maximum heat input capacity of ~~2,244.1~~ **1,944.1** MMBtu/hr (per unit), and exhausts to stacks designated as CT**G**01, CT**G**02, and CT**G**03 respectively.

(b) Three (3) heat recovery steam generators designated as unit HRSG1, HRSG2, and HRSG3, with three (3) associated duct burners, with a maximum heat input capacity of 300 MMBtu/hr (per unit).

(c) Three (3) selective catalytic reduction systems, designated as units SCR1, SCR2, and SCR3

(d) Three (3) cooling towers, designated as CT01, CT02, and CT03 and exhausts to stacks designated as CT01, CT02, and CT03.

(e) One (1) **natural gas fired** auxiliary boiler, designated as unit SUB with a maximum heat input rating of 35 MMBtu/hr, and exhausts to stack designated as SUB.

(f) One (1) ~~emergency diesel~~ **standby** generator (DGS) utilizing low sulfur diesel fuel, with a maximum heat input capacity of 8.40 MMBtu/hr and exhausts to stack designated as DGS.

(g) One (1) backup fire pump (DFP) utilizing low sulfur diesel fuel, with a maximum rated heat input capacity of 2.0 MMBtu/hr and exhausts to stack designated as DFP.

(h) Three (3) natural gas fuel pre-heaters, designated as GH01, GH02, and GH03 with a maximum heat input rating of 5.0 MMBtu/hr **each.**

Comment 2: Condition C.2(a)(1) – It would be appreciated if the term "Individual(s)" would be replaced with "Position(s)". This would alleviate the plant from changing the PMP every time there is a change in personnel.

Response 2: While the rule specifically reads "individual(s)", the term is not defined in the rule. The common meaning of individual can include "position(s)" as this does identify a distinct entity. Condition C.2(a)(1) is changed as follows:

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) **or position(s)** responsible for inspecting, maintaining, and repairing emission control devices;

Comment 3: Condition C.16(a) – The phrase "including startup and shutdowns…" should be changed to "as well as startups and shutdowns…" as a startup or shutdown should not be considered a malfunction. In addition, the phrase "Vigo County Air Pollution Control (VCAPC)" should be deleted from the paragraph.

Response 3: Upon review of the permit, OAQ noticed that Section C contained two conditions numbered C.16. The condition which the source is commenting on is actually Condition C.17 and the remaining conditions in Section C will be renumbered accordingly. This condition is not intended to require the source to keep records of startups and shutdowns nor is it saying that a startup or shutdown is a malfunction. It requires record keeping of malfunctions that occur during startups and shutdowns. Condition D.1.19 requires record keeping of startups and shutdowns. OAQ will change the condition so there is no misunderstanding. OAQ will also remove reference to the Vigo County local agency as this clearly does not belong in this permit. Condition C.17 is changed as follows:

C.17 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 **malfunctions during** 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.

Comment 4: Condition D.1(d) – Again, this paragraph should read, “Three (3) cooling towers designated as units CT01, CT02 and CT03” as the cooling towers do not exhaust though the turbine stacks.

Response 4: The facility description box for Section D.1 is changed as follows to match Comment 1. Item (d) matches the unit and stack designations contained in the permit application and will not be changed.

SECTION D.1 FACILITY CONDITIONS – Combined Cycle Operation

(a) Three (3) natural gas-fired combustion turbine generators, designated as units CTG01, CTG02, and CTG03, with a maximum heat input capacity of ~~2,244.1~~ **1,944.1** MMBtu/hr (per unit) on a higher heating value basis, and exhausts to stacks designated as CT**G**01, CT**G**02, and CT**G**03, respectively.

(b) Three (3) heat recovery steam generators, designated as units HRSG1, HRSG2, and HRSG3 with three (3) associated duct burners, with a maximum heat input rating of 300 MMBtu/hr (per unit).

(c) Three (3) selective catalytic reduction systems, designated as units SCR1, SCR2, and SCR3

(d) Three (3) cooling towers, designated as units CT01, CT02, and CT03 exhausts to stacks designated CT01, CT02, and CT03

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

Comment 5: Condition D.1.5(b) and (c) - As we have discussed, we would like to delete lb/hr limitations to startup and shutdowns for the following reasons:

a) The roll (rotating turbine up to speed), purge (all gases are purged from the gas turbine prior to introduction of flame) and coast (bring turbine up to firing speed) sequence takes approximately 20 minutes total and no emissions of combustion pollutants have occurred as no flame is present.

b) When the gas turbine is fired it is brought up to full speed-no load (FSNL). The 8% load condition is used to heat the HRSG and steam turbine in a controlled manner. The length of time in FSNL shortens considerably if the gas turbine is in warm or hot startup.

c) When the HRSG and steam turbine come up to temperature the gas turbine load can be increased. It takes approximately 30 to 40 minutes to go from 8% to 100% load. At 70 % load, all components are at temperature and startup is considered complete.

d) Ammonia can be introduced into the SCR system when the catalyst is at 500 ^{0}F or approximately 60 minutes into a cold startup cycle. At that time, it is estimated that the SCR can control at 50% control efficiency. The SCR runs at 50% control efficiency until startup is complete. For warm startup it is estimated that ammonia can be introduced at approximately 45 minutes into the process (when the catalyst is at temperature), For hot startup, ammonia is introduced when the turbine begins to pick up load at 31 minutes. For shutdown ammonia introduction is stopped just before the turbine goes into FSNL.

e) These are expected emissions that are not guaranteed by GE or the SCR manufacturer. Any permit conditions regarding startup and/or shutdown emissions should be in terms of lbs per event and not a lb/hr number. We would prefer a time limit and/or description for startup and shutdown.

Response 5: OAQ agrees that the startup and shutdown emissions should be expressed in pounds per event. Condition D.1.5 is changed as follows:

D.1.5 Startup and Shutdown Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), a startup or shutdown is defined as less than seventy (70) percent load. Each combustion turbine generating unit shall comply with the following:

(a) Each startup period shall not exceed 250 minutes, and each shutdown period shall not exceed two (2) hours. Each turbine shall not exceed 1670 hours per year for startups and 800 hours per year for shutdowns.

(b) The NO_X emissions from each combustion turbine stack shall not exceed ~~51.04 lb/hr for a startup~~ **275 pounds per startup** and ~~17.5 lb/hr for a shutdown~~ **35.0 pounds per shutdown**.

(c) The CO emissions from each combustion turbine stack shall not exceed ~~281.7 lb/hr for a startup,~~ **1173.75 pounds per startup** and ~~130.75 lb/hr for a shutdown~~ **336 pounds per shutdown**.

Comment 6: Condition D.1.6(a)(1) – Please add the word “block” to the phrase “three (3) hour averaging period” so that it reads “three (3) hour block averaging period.”

Response 6: It is OAQ’s intention that the emission limitations and averaging times stated in this permit be met during all times the emitting units are in operation. A “three (3) hour block averaging period” would average over a three (3) hour period regardless as to whether the emitting unit was operating or not. This is not OAQ’s intent. To clarify OAQ’s intented interpretation of the condition the phrase “three (3) hour averaging period” will be changed to “three (3) operating hour averaging period”. Condition D.1.6(a)(1) is changed as follows:

D.1.6 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines/Duct Burners

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

(1) During normal combined cycle operation (seventy (70) 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) **operating** hour **rolling** averaging period, which is equivalent to 25.9 pounds per hour for each combustion turbine.

Comment 7: Condition D.1.7
(a)(1) - Please add the word “block” to the phrase “24 hour averaging period” so that it reads “24 hour block averaging period.”
(a)(2) - Please add the word “block” to the phrase “24 hour averaging period” so that it reads “24 hour block averaging period.”

Response 7: It is OAQ’s intention that the emission limitations and averaging times stated in this permit be met during all times the emitting units are in operation. A “24 hour block averaging period” would average over a 24 hour period regardless as to whether the emitting unit was operating or not. This is not OAQ’s intent. The request to add “block” is denied. To clarify OAQ’s intented interpretation of the condition the phrase “24 hour averaging period” will be changed to “24 operating hour averaging period”. Conditions D.1.7(a)(1) and D.1.7(a)(2) are changed as follows:

D.1.7 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:

(1) During normal combined cycle operation (seventy (70) percent load or more), the CO emissions from each combustion turbine shall not exceed 9.0 ppmvd corrected to fifteen (15) percent Oxygen on a 24 **operating** hour **rolling** averaging period, and 35.1 pounds per hour for each combustion turbine.

(2) During normal combined cycle operation (seventy (70) percent load or more), the CO emissions from each combustion turbine when its associated duct burner is operating shall not exceed 12.2 ppmvd corrected to fifteen (15) percent oxygen on a 24 **operating** hour **rolling** averaging period, and 62.0 pounds per hour for each combustion turbine and duct burner

Comment 8: Condition D.1.16
(c) – We would like this testing requirement to be deleted for reasons given above regarding startup and shutdowns. If ultimately there will be no emission limits for startup and shutdown, there should be no testing requirements. At the very least, this testing requirement should be for one representative turbine stack only.
(d) – We believe you meant to test “NOx and CO” in this paragraph, not “NOx and SO_2.”

Response 8: The source is required to minimize emissions both during normal operation and during startups and shutdowns. Emission limitations for NOx and CO are contained in the permit and therefore the requirement to test for NOx and CO shall remain. There will be no change to condition D.1.16(c). Testing required under condition D.1.16(d) will be used to show compliance with condition D.1.10. Condition D.1.10 references NSPS NOx and SOx limits for the combustion turbines. Therefore condition D.1.16(d) is correct in requiring test for NOx and SO_2. There will be no change in condition D.1.16(d). OAQ has however noticed that condition D.1.10(2) makes an incorrect reference to condition D.2.8. This reference will be removed from the condition. Condition D.1.10 is changed as follows:

D.1.10 40 CFR 60, Subpart GG (Stationary Gas Turbines)

The three (3) 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~~.

Comment 9: Condition D.1.18(b)(1) – Please add the word "block" to the phrase "24 hour averaging period" so that it reads "24 hour block averaging period."

Response 9: It is OAQ's intention that the emission limitations and averaging times stated in this permit be met during all times the emitting units are in operation. A "24 hour block averaging period" would average over a 24 hour period regardless as to whether the emitting unit was operating or not. This is not OAQ's intent. To clarify OAQ's intented interpretation of the condition the phrase "24 hour averaging period" will be changed to "24 operating hour averaging period". OAQ is also changing "three (3) hour block" to "three (3) operating hour averaging period". Condition D.1.18(b)(1) is changed as follows:

D.1.18 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 CTG01, CTG02 and CTG03 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 (ppm) at 15% O_2 over a three (3) **operating** hour ~~block~~ **rolling averaging period**. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) 15% O_2 over a twenty four (24) **operating** hour **rolling** 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.1.5 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.

Comment 10: Condition D.1.19(b)(2) – This paragraph should read, “The total number of minutes for startup or shutdown per 24-hour day per turbine.”

Response 10: It is OAQ’s intention that the emission limitations and averaging times stated in this permit be met during all times the emitting units are in operation. A “24 hour day per turbine” could be interpreted to mean an average over a 24 hour period regardless as to whether the emitting unit was operating or not. This is not OAQ’s intent. To clarify OAQ’s intented interpretation of the condition the phrase “24 hour averaging period per turbine” will be changed to “24 operating hour averaging period per turbine”. Condition D.1.19(b)(2) is changed as follows:

D.1.19 Record Keeping Requirements

(a) To document compliance with Conditions D.1.2, D.1.5 through D.1.8, 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) 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.1.5, 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 **operating** hour **rolling** 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.1.6 and D.1.7, 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.1.18, 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.1.10, 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.

Comment 11: Condition D.3(f) – The word "emergency" should be replaced with "standby".

Response 11: OAQ makes the following change to the description box for Section D.3 and also Condition A.2(f) of the permit: (Condition A.2(f) is shown in the response to Comment 1)

SECTION D.3 FACILITY CONDITIONS – Backup Equipment

(f) One (1) ~~emergency~~ **standby** diesel generator designated as DGS, utilizing low sulfur fuel, with a maximum heat input capacity of 8.40 MMBtu/hr and exhausts to a stack designated as DGS.
(g) One (1) backup fire pump designated as DFP, utilizing low sulfur diesel fuel, with a maximum rated heating capacity of 2.0 MMBtu/hr and exhausts to a stack designated as DFP.
(h) Three (3) natural gas fuel pre-heaters, designated as GH01, GH02, and GH03 with a maximum heat input rating of 5.0 MMBtu/hr each.
(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

On June 11, 2001 a public hearing was held on the proposed Cogentrix Lawrence County LLC Prevention of Significant Deterioration permit and Acid Deposition Control Program permit.

Mr. Ned Barretto presented the following questions:

Comment 1: What type of pollution control equipment does this plant have?

Response 1: Control equipment associated with the operation of the combined cycle plant consist of dry low-NOx (DLN) combustion burners located inside the turbines and add on control equipment consisting of a selective catalytic reduction system to control NOx emissions. While the DLN is specifically used to reduce the formation of thermal NOx, it also affects the generation of CO and VOC as the formation of these pollutants are the result of incomplete combustion. All other pollutants are controlled through the use of good combustion practices.

Comment 2: Does the turbine run on steam like most conventional turbines?

Response 2: The steam turbine runs on steam. The combustion turbines run on natural gas and drive an electric generator. The exhaust from the combustion turbines is directed to a heat recovery steam generator (HRSG) and steam from the HRSG is used to drive a condensing steam turbine which also drives an electric generator.

Comment 3: What exactly is this going to be put into the air and how much?

Response 3: The following table summarizes the emissions after controls of the criteria pollutants for the proposed project. It should be noted that these emissions are based on operation at 8760 hours per year. Actual operation and emissions will be less. Hazardous air pollutants (HAPs) will be emitted at levels less than 10 tons per year for any single HAP and less than 25 tons per year for the combination of HAPs.

Pollutant	Emissions (ton/yr)
PM	332.14
PM_{10}	332.14
SO_2	174.81
VOC	100.94
CO	1454.70
NO_X	439.38

Comment 4: Will the plant be continuously monitored by IDEM or EPA and who controls these monitors?

Response 4: The plant will have continuous emission monitors (CEMs) for NOx and CO. These are machines that measure on a continuous basis the pollutants (NOx and CO) being released by the source. The source is additionally required to keep records of natural gas combustion, sulfur and nitrogen content of the natural gas used, startups and shutdowns, all CEMs data and emission rates for NOx and CO in pounds per hour and parts per million. The source is required to report to OAQ quarterly the CEMs data, startups and shutdowns and periods of excess emissions.

The CEMs will be owned and operated by the source. The OAQ is also involved in approving the calibration/RATA (Relative Accuracy Test Audits) of the CEMs. OAQ air inspectors regularly make unannounced visits and inspections of major sources several times yearly to assure compliance with all applicable permit terms and conditions.

Mr. Larry Sipes presented the following questions:

Comment 1: Will this plant when it is completed and put into service meet the requirements of the recent standards (NOx SIP Call) approved by the Air Pollution Control Board?

Response 1: The Indiana Air Pollution Control Board (APCD) on June 6, 2001 adopted the Indiana Nitrogen Oxides Control Rules. This rule will work to meet ozone-based health standards statewide and will help to meet the new ozone standards recently set by EPA. Major elements of the Indiana Nitrogen Oxides Control Rule include:

a) a 31% statewide reduction in NOx emissions from 1995 levels by May 1, 2004,
b) a 66% statewide reduction in NOx emissions from 1995 levels emitted from fossil-fuel-fired electric plants by May 31, 2004,
c) a 55% reduction in NOx emissions from large industrial boilers by May 31, 2004,

d) establishment of a cap and trade emission allowance program that allows the trading of NOx “allowances” between facilities for cost effective approaches to NOx reduction goals,
e) incentives for energy efficiency/renewable sources of power
f) an effective continuous emission monitoring system to assure compliance among most large emitters for NOx emission requirements and
g) control requirements for large cement kilns that require either the use of specified technology or an emissions reduction of 30 percent.

This source will be required to operate within the reductions stated by this rule.

Mr. David Rhum presented the following questions:

Comment 1: What is the difference in emissions of pollutants from a gas fired versus a coal fired plant?

Response 1: Natural gas is one of the cleanest burning fuels that can be used for combustion. Coal on the other hand is one of the dirtiest fuels that can be combusted. In general coal emissions for some pollutants can be several times larger than a similar sized natural gas fired plant. The following table compares the emissions (after controls) from the Cogentrix plant with those from a fluidized bed coal fired plant with an even lesser capacity. This particular boiler is a circulating fluidized bed boiler designed to minimize SOx emissions as compared to a conventional utility coal fired boiler.

	Cogentrix 820 MW Natural gas fired plant (tons/year)	Fluidized bed 500 MW coal fired plant (tons/year)
PM	332.14	350
SOx	174.81	5000
VOC	100.94	300
CO	1454.70	5800
NOx	439.38	2700

Written comments were received from the Honorable John A. Williams, Mayor of Bedford, IN supporting the project, Mr. Stephen Loeschner on June 25, 2001 and June 12, 2001 & July 2, 2001 via email, combined comments from the Hoosier Environmental Council (HEC), Citizens Action Coalition of Indiana (CACI) and Mr. Stephen Loeschner on June 25, 2001, Mr. Larry Sipes on June 25, 2001, Mr. Andrew J. Sobiech on June 25, 2001 and from Berger and Berger and Dr. Phyllis J. Fox representing the South Central Indiana Building and Construction Trades Council on June 25, 2001. On July 13, 2001, by way of telefax and mail delivery, OAQ received a letter from Mr. Randy Brown of Plumbers and Steamfitters UA Local Union 136 withdrawing the comments received by Berger and Berger and Dr. Phyllis J. Fox representing the South Central Indiana Building and Construction Trades Council. OAQ will therefore not provide responses to these comments. The comment by Mayor Williams does not requires a response. All other comments are responded to below.

Mr. Stephen Loeschner, the HEC and the CACI provided similar and overlapping comments. The following summarizes significant points of the comments received:

Comment 1: BACT for NOx must require operation of the pollution control equipment whenever operating temperatures make it useful.

Response 1: The comment is referring to Condition D.1.6(a)(5) which requires the selective catalytic reduction (SCR) system to operate at all times except during startup and shutdown and

Condition D.1.5 which defines startup and shutdown as less than seventy percent (70%) load. Generally for this model of turbine, the control equipment is operational at fifty percent (50%) load or greater and less than fifty percent (50%) load is considered startup and shutdown. The source claims to have contractual obligations to maintain operations at or above 70% of full load. OAQ feels that this is purely a business decision on the part of Cogentrix and agrees with the commentors that the control equipment should be operational as soon as the temperature parameters are achieved for such operation. As OAQ desires to minimize the emissions from the unit operations as much as possible, startup will be redefined as less than fifty percent (50%) load. This change in the definition of startup and shutdown will also be reflected in Conditions D.1.6(a)(1) & (a)(2), D.1.7(a)(1) & (a)(2) and D.1.8(a)(1) & (a)(2). Condition D.1.5 is changed as follows:

D.1.5 Startup and Shutdown Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), a startup or shutdown is defined as less than ~~seventy (70)~~ **fifty (50)** percent load. Each combustion turbine generating unit shall comply with the following:

(a) Each startup period shall not exceed 250 minutes, and each shutdown period shall not exceed two (2) hours. Each turbine shall not exceed 1670 hours per year for startups and 800 hours per year for shutdowns.

(b) The NO_X emissions from each combustion turbine stack shall not exceed 275 pounds per startup and 35.0 pounds per shutdown.

(c) The CO emissions from each combustion turbine stack shall not exceed 1173.75 pounds per startup and 336 pounds per shutdown.

Comment 2: BACT for NOx must be at least as stringent as 2 ppm, 1-hour average, with and without duct burner firing.

Response 2: Federal regulations found in Parts 51 and 52 of the Title 40 Code of Federal Regulations (40 CFR Parts 51 and 52) specify that one of two levels of emission control will apply to a new or modified, stationary source of criteria pollutants subject to major source permitting requirements. The control requirements are pollutant specific and depend on an area's attainment status for the ambient air quality standards. One federal requirement is termed "lowest achievable emission rate (LAER)" and is required when an area is nonattainment for a standard. The other federal requirement is termed "best available control technology (BACT)" and is required when an area in attainment or has an "unclassified" designation, for a standard. LAER determinations do not consider cost while BACT determinations do consider energy, environmental, economic and other cost associated with the technology. BACT is performed using a "top-down" approach where all available control technologies are ranked in descending order of control effectiveness. The top-down BACT analysis typically begins by considering emission limitations that have been established by LAER. In some cases those limits are accepted as BACT. However, further consideration of energy, environmental, and economic impacts may establish different emission limits as BACT.

Lawrence County is classified as attainment or unclassifiable for all criteria pollutants, therefore a BACT analysis is required. In researching the applicant's BACT analysis, OAQ draws on it's own permits, the USEPA RACT/BACT/LAER clearinghouse (RBLC) and information from other states and overseas. OAQ has consistently been as stringent or more stringent in regards to oxides of nitrogen (NOx) BACT than any other Region 5 state. Recent OAQ permits have determined that BACT for NOx is 3.0 ppm @ 15% O_2 based on a three (3) operating hour rolling averaging period. Mr. Loeschner claims that NOx BACT should be 2.0 ppm @ 15% O_2 based on a one (1) hour average. OAQ believes that Mr. Loeschner is referring to NOx levels achieved through the use of a control technology called SCONOx which has been used on combined cycle projects where the combustion turbine output is less than 100 MW. Despite the claims by the manufacturer of this control technology that there are no scale up problems in applying this technology to turbines greater than 100 MW (as is the case with the Cogentrix project) it has not been applied to any such project. OAQ contacted the manufacturer and he confirmed that SCONOx technology has not been applied to a GE7FA combined cycle turbine project. OAQ believes that while this technology has been successfully demonstrated on the smaller turbines (less than 100 MW) it has not been demonstrated on the larger turbines (greater than 100 MW). This determination is consistent with that of other state permitting agencies and EPA Regions. OAQ feels that its' NOx limit of 3.0 ppm @ 15% O_2 is protective of the environment and human health. The three operating hour rolling averaging period was chosen because the performance test to show compliance consist of an average taken from three (3) one hour test. The NAAQS for NOx is an annual average. Air quality planning for ozone uses daily or seasonal emission rates.

Comment 3: BACT for CO must be at least as stringent as 2 ppm, 3-hour average, with and without duct burner firing.

Response 3: NOx emissions from combustion turbines consist of two primary types: fuel NOx and thermal NOx (Prompt NOx is considered to be a component of thermal NOx). Fuel NOx formation is dependent on the fuel nitrogen content and combustion oxygen levels. Natural gas contains negligible amounts of fuel nitrogen and is therefore insignificant. Thermal NOx is created by the high temperature reaction of nitrogen and oxygen in the combustion air. The amount formed is a function of (among other things) flame temperature, residence time and fuel/air ratios. CO emissions from a combustion turbine are the result of incomplete combustion of natural gas. Thus, there exist a relationship between thermal NOx and CO in natural gas fired turbines as both are related to the combustion process. Control measures taken to decrease the formation of NOx during combustion may inhibit complete combustion, which could increase CO emissions. The comments received refer to an issued Illinois permit where the initial CO limit was stated as 4.0 ppm based on a one (1) hour average. This limit is to be achieved without the use of add-on control equipment. What the comments failed to mention was that the NOx limit for this same permit was 4.5 ppm on a one (1) hour average during duct firing and 3.5 ppm on a twenty four (24) hour average during non duct firing. Both of these limits exceed OAQ's NOx BACT. So in comparing these two permits both NOx and CO should be examined, not just the CO or just the NOx. The basis for the comment on CO BACT being 2.0 ppm based on a three (3) hour average is with the use of an oxidation catalyst as add-on control. The applicant examined the application of an oxidation catalyst as part of the CO BACT analysis. Use of an oxidation catalyst was determined to be economically infeasible at a cost effectiveness of $7,850 per ton of CO removed. Given the regional air quality conditions and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, the proposed emission limits are believed to be representative of a top level emission control. There are no expected adverse economic, environmental or energy impacts associated with the proposed control alternative. Please refer to page 2 of this document for additional discussion on OAQ's CO BACT.

Comment 4: 40 CFR 52.21(m) data must be required for O_3, PM, and NOx, and the application suspended for at least four months while it is produced.

Response 4: The Clean Air Act Amendments of 1977, Part D, Prevention of Significant Deterioration, require that certain new major stationary sources and major modifications be subject to preconstruction review which includes an ambient air quality analysis. The Act requires that this analysis be conducted in accordance with regulations promulgated by the

USEPA. 40 CFR 52.21(m)(1)(iv) sets the requirements for one (1) year pre-construction monitoring data. The PSD regulations contain a list of air quality concentrations as a criteria for exempting proposed sources or modifications from collecting monitoring data. Monitoring data will be required if the existing air quality and the impact of the proposed source or modification is equal to or greater than these concentrations. In certain cases, even though the air quality impact or background air quality may be less than these concentrations, monitoring data may be required if the proposed source or modification will impact a Class I area, nonattainment area, or area where the PSD increment is violated.

For criteria pollutants (SO_2, CO, NO_2) continuous air quality monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. For VOC emissions, continuous ozone monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. For PM_{10} and lead, the 24-hour manual method will be used to establish the existing air quality concentrations. However, no pre-construction monitoring data will generally be required if the ambient air quality concentration before construction is less than the significant impact increments. OAQ generally uses representative data to fulfill this requirement.

The following table taken from “Appendix B - Air Quality Analysis” of the Technical Support Document summarizes the impacts of the proposed facility.

Summary of OAQ Significant Impact Analysis (ug/m^3)				
Pollutant	Year	Time-Averaging Period	Cogentrix Maximum Modeled Impacts	Significant Impact Increments
CO	1986	8-hour	222.8	500
NO_2	1987	Annual-8760 hours	0.85	1.0
SO_2	1990	24-hour	2.7	5.0
PM_{10}	1990	24-hour	4.997	5.0

As shown from the table, modeled concentrations are below significant impact increments and no further air quality modeling was required (as well as no pre-construction monitoring). Had modeled concentrations exceeded the significant impact increments the source would have been required to conduct more refined modeling which includes source inventories and background data. Due to the PM_{10} concentration coming within 0.003 ug/m^3 of the significant impact increment, OAQ conducted refined modeling to compare the air quality impacts to the NAAQS and PSD increments for PM_{10}. OAQ modeled emission inventories of PM_{10} sources within a 50 kilometer radius of the Cogentrix site. All maximum concentrations of PM_{10} for the 24-hour and annual time-averaged periods were below their respective NAAQS limit and further modeling was not required. (Please see “Appendix B - Air Quality Analysis” of the Technical Support Document for the complete air quality analysis.)

With the exception of the Whiting Project (application # 11194) which was a cogeneration project and an existing monitor was already on site to satisfy the pre-construction monitoring requirement, no other merchant plant PSD application has triggered this requirement.

Comment 5: To prove formaldehyde (H_2CO) minor status to avoid MACT, identical conservatively stringent conditions from 12517 (PSEG Lawrenceburg permit issued 6/7/01) must be imposed, or continuous emission monitoring must be required. The PTE of formaldehyde in condition D.1.12 is greater than 10 tons/yr (2244.1 MMBtu/hr x 3 x 0.00036 lbs/MMBtu x 1 ton/2000 lbs x 8760 hr/yr = 10.62 tons/yr) and thus either MACT or a synthetic minor limit is required.

Response 5: Maximum Achievable Control Technology (MACT) is required whenever a source emits ten (10) or more tons of a single hazardous air pollutant (HAP) or the combination of HAPs emitted by the source exceeds twenty-five (25) tons or more. Electric steam generating units were exempt from the MACT requirements until such time as they were added to the source category list under Section 112(c)(5) of the Clean Air Act. The comment makes claim that formaldehyde (H_2CO) emissions could be greater than ten (10) tons per year and therefore could be subject to a MACT analysis. He requests an enforceable permit condition limiting this HAP to less than ten (10) tons per year. The OAQ acknowledges that the emission table shown in the "Source Status" section of the Technical Support Document does not have the correct value for the single or combination of HAPs and will revise this table.

On April 21, 2000, through an interpretative rule, USEPA clarified that all new major source stationary combustion turbines are subject to case-by-case MACT determinations under Sections 112(g) and 112(j) of the Clean Air Act, whether or not they are part of a combined cycle plant. (A combined cycle plant is considered an electric steam generating unit.) On December 14, 2000, the USEPA announced a project to develop emission regulations under Section 112 for oil and coal fired electric steam generating units. This all means that the combustion turbines (as per the interpretative rule) are considered for MACT applicability while the heat recovery steam generator and natural gas fired duct burners (December 14, 2000 project only addresses oil and coal fired units) are exempt from the MACT requirements. Any HAPs resulting from the duct burner operation are not considered when evaluating MACT applicability.

The heat input for a single combustion turbine is 1944.1 MMBtu/hr and the heat input for a single duct burner is 300 MMBtu/hr. The combined heat input for both the combustion turbine and duct burner is 2244.1 MMBtu/hr. MACT applicability is only based on the combustion turbine heat input. The commenter was not correct when he determined the formaldehyde emissions based on a heat input of 2244.1 MMBtu/hr. It should only have been based on the combustion turbine heat input of 1944.1 MMBtu/hr. In the permit application, (Appendix A, Table A-2 "Combustion Air Toxics Emissions Calculations") Cogentrix uses an emission factor of 0.000275 lb/MMBtu for the formaldehyde emissions from the combustion turbines. This emission factor was obtained by applying a factor of 2.5 to the average emission factor for formaldehyde emissions as listed in the latest California Air Resources Board (CARB) emission inventory database. The emission factor listed in the CARB database is 0.00011 lbs/MMBtu. This is the formaldehyde emission factor contained in the PSEG permit referenced by the comment. The PSEG source voluntarily accepted a lower emission limit. The OAQ only has the authority to limit formaldehyde emissions to less than ten (10) tons per year. Using the 0.000275 lb/MMBtu emission factor yields annual formaldehyde emissions from the three (3) combustion turbines of approximately 7.025 tons per year.

(1944.1 MMBtu/hr x 3 x 0.000275 lbs/MMBtu x 1 ton/2000 lbs x 8760 hr/yr)

Based on this formaldehyde emission factor, the combustion turbines are not subject to the MACT requirements. The emission factor which would yield formaldehyde emissions of ten (10) tons per year is 0.00039 lbs/MMBtu and can be calculated as follows:

(10 tons/yr) / (1944.1 MMBtu/hr x 3 x 1 ton/2000 lbs x 8760 hr/yr)

It is believed that the emission factor contained in condition D.1.12 may be a typing error as this value should have been 0.00039 not 0.00036 to limit formaldehyde emissions to less than ten (10) tons/yr.

The OAQ has discussed this matter with the source and they have agreed to the 0.000275 lb/MMBtu emission rate in an enforceable permit condition to limit formaldehyde emissions. The OAQ requires the source to stack test one of the combustion turbines to confirm the formaldehyde emission rate. Condition D.1.12 is an enforceable permit condition limiting the HAPS from the combustion turbines. Condition D.1.12 is changed as follows:

D.1.12 Formaldehyde Limitations **[326 IAC 2-1.1-5] [326 IAC 2-4.1]**

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~~ **0.000275** pounds of formaldehyde per MMBtu.

It is OAQ's policy that the Technical Support Document reflect the draft proposed permit that was presented for public notice. The Technical Support Document Addendum (this document) is used to document any changes to the permit and associated documents after the public comment period. The "Source Status" table in the Technical Support Document is therefore revised as follows to match the emission calculations in Appendix A and the source permit application. It should be noted that the "Single HAP" value does not represent the value used for MACT determination nor does it represent formaldehyde emissions as formaldehyde is not the largest HAP.

Pollutant	Emissions (ton/yr)
PM	332.14
PM_{10}	332.14
SO_2	174.81
VOC	100.94
CO	1454.70
NO_X	439.38
Single HAP	~~4.01~~ **9.62**
Combination HAPs	~~10.66~~ **17.34**

Comment 6: For public welfare, the NH_3 slip emission concentration must be reduced to 2 ppm, and the public must be informed of the maximum possible annual emission tonnage.

Response 6: Selective catalytic reduction uses ammonia as a reducing agent in controlling NOx emissions from gas turbines. The ammonia injected exhaust stream enters and reacts with the catalyst to form nitrogen (N_2) and water (H_20). The portion of the unreacted ammonia passing through the catalyst and emitted from the stack is called ammonia slip. Ammonia is not a federal hazardous air pollutant or a State identified toxic air contaminant. Currently, ammonia is not a regulated pollutant under new source review rules. New source review rules regulate criteria pollutants and their regulatory precursors. Although ammonia is recognized to contribute to ambient PM_{10} concentrations, it is not listed in any new source review rule as a precusor to PM_{10}. However, the PSD program does provide for the consideration of unregulated pollutants. In an August 15, 1986 determination, EPA Region 9 stated the following:

> "In a BACT decision, a permitting agency must consider not only the environmental impact of the controlled regulated pollutant but must also consider the environmental impacts of any unregulated pollutants that might be affected by the choice of control technology."

Ammonia slip occurs in several ways. One possible cause of ammonia slip is when the catalyst temperature falls outside the optimum catalyst reaction range. A second cause occurs when the catalyst itself becomes prematurely fouled or exceeds its life expectancy. Some ammonia slip will occur regardless of the efficiency of the unit due to the SCR manufacturer's recommendation to inject ammonia above what is stoichiometrically required. The ammonia slip associated with this project has been designed to not exceed 10 ppm to ensure that the proposed NOx emission limit is met. Proper control of the ammonia injection will minimize the ammonia slip well below the designed maximum.

Environmental impacts associated with the use of ammonia were evaluated by the source and included with the permit application. Ammonia salt precipitation resulting from the proposed facility will have a negligible impact on the environment. Ammonia salt formation is a function of the fuel-bound sulfur content and the amount of excess ammonia in the catalyst bed. The potential for the formation of ammonia salts is minimal due to the low sulfur content of natural gas. Other environmental impacts associated with the use of ammonia have to do with the transportation, handling, and storage of aqueous ammonia which can result in potential spills and evaporation of ammonia into the atmosphere. The overall risk of this occurrence is considered low. There are no anticipated environmental impacts associated with the spent catalyst material because the metal is shipped back to the manufacturer for recycling.

OAQ does however agree that the public should be aware of the annual amount of ammonia potentially emitted by the source. Table A-1 of Appendix A of the permit application list annual ammonia emissions of 446.8 tons per year. Condition D.1.13 is changed as follows:

D.1.13 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.~~

(a) the ammonia emissions from each combustion turbine stack shall not exceed ten (10) ppmvd corrected to 15% O_2.

(b) annual ammonia emissions shall not exceed 446.8 tons per year.

Mr. Larry Sipes submitted the following written comments:

Comment 1: "When I look at the positives of permanent employment of 20 persons, the additional property tax of $1,000,000.00 per year after 10 years, and the cash injected into our economy from 200 construction workers over a two year period, versus, the negatives of producing electricity not to be used locally and creating another major source of emissions, I think the negatives far outweigh the positives.

We of this generation have a responsibility to preserve and pass on to the next generation an environment as pollution free as possible, with clean air and water.

With the amount of activity we have seen in applications for Merchant Power Plants in Indiana over the prior two years, I fear we are becoming a dumping ground for this type of activity.

It is my sincere hope approval of these permits will be denied."

Response 1: The OAQ works to safeguard the quality of Indiana's air through implementing the requirements of the Clean Air Act, developing state rules governing air quality standards, evaluating and issuing permits for construction and operation and monitoring Indiana's air quality. These programs continue to reduce the levels of air pollution across the state every year. The OAQ routinely performs air quality analysis to insure that issuance of a permit will not result in a violation of any state or federal air regulations and standards. A permit would be denied if the application does not meet the requirement of 326 IAC2-2 or if the source would pose a threat to public health. In addition, the air quality analysis conducted demonstrates that air quality in the vicinity of the plant will continue to comply with the air quality standards. No significant impact on public health or welfare is expected to occur as a result of the emissions from the proposed facility.

If the applicant complies with all state and federal requirements and the air quality analysis demonstrates that the source will not have significant impact on the environment and human health, then the IDEM is required by law to issue the permit. If significant sources are located nearby, then the OAQ takes that into account when performing the air quality demonstration.

Mr. Andrew J. Sobiech submitted the following written comments:

Comment 1: "The permit for the above referenced project should NOT be issued. The project will create air and water pollution where there is none, and will not benefit the residents of Lawrence County or the State of Indiana. In addition to the unnecessary emissions of toxic substances into the air and water, the project could cause water shortages, and cause the price of natural gas to go up. The very few jobs that the project might create long term are not worth the negative impact on the environment."

Response 1: As mention in the response to the above comment, if the applicant complies with all state and federal requirements and the air quality analysis demonstrates that the source will not have significant impact on the environment and human health, then the IDEM is required by law to issue the permit.

Indiana Department of Environmental Management
Office of Air Management

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

Source Background and Description

Source Name:	Cogentrix Lawrence County, LLC
Source Location:	Rural Route 3, Mitchell, IN 47446
County:	Lawrence
Construction Permit No.:	CP-093-12432-00021
SIC Code:	4911
Permit Reviewer:	Sherry Harris

The Office of Air Management (OAQ) has reviewed an application from Cogentrix Lawrence County, LLC relating to the construction and operation of an 820 megawatts natural gas combined cycle merchant power plant. The permit specifies no backup fuel to be used, the source will fire only natural gas, and any addition of a backup fuel in the future will go through Prevention of Significant Deterioration (PSD) review. The source will consist of the following equipment:

(a) Three (3) natural gas-fired combustion turbine generators, designated as units CTG01, CTG02, and CTG03 with a maximum heat input capacity of 2,244.1 MMBtu/hr (per unit), and exhausts to stacks designated as CT01, CT02, and CT03 respectively.

(b) Three (3) heat recovery steam generators designated as unit HRSG1, HRSG2, and HRSG3, with three (3) associated duct burners, with a maximum heat input capacity of 300 MMBtu/hr (per unit).

(c) Three (3) selective catalytic reduction systems, designated as units SCR1, SCR2, and SCR3

(d) Three (3) cooling towers, designated as CT01, CT02, and CT03 and exhausts to stacks designated as CT01, CT02, and CT03.

(e) One (1) auxiliary boiler, designated as unit SUB with a maximum heat input rating of 35 MMBtu/hr, and exhausts to stack designated as SUB.

(f) One (1) emergency diesel generator (DGS) utilizing low sulfur diesel fuel, with a maximum heat input capacity of 8.40 MMBtu/hr and exhausts to stack designated as DGS.

(g) One (1) backup fire pump (DFP) utilizing low sulfur diesel fuel, with a maximum rated heat input capacity of 2.0 MMBtu/hr and exhausts to stack designated as DFP.

(h) Three (3) natural gas fuel pre-heaters, designated as GH01, GH02, and GH03 with a maximum heat input rating of 5.0 MMBtu/hr.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)
CTG 01	Combustion Turbine Generator with Duct Burner	175	18.0	1,116,709	174
CTG 02	Combustion Turbine Generator with Duct Burner	175	18.0	1,116,709	174
CTG 03	Combustion Turbine Generator with Duct Burner	175	18.0	1,116,709	174
CT 01	Cooling Tower	35.0	33.0	391,313/cell	85
CT 01	Cooling Tower	35.0	33.0	391,313/cell	85
CT 01	Cooling Tower	35.0	33.0	391,313/cell	85
GH 01	Fuel Pre-Heater	100	2.0	2,997	980
GH 02	Fuel Pre-Heater	100	2.0	2,997	980
GH 01	Fuel Pre-Heater	100.0	2.0	2,997	980
SUB	Auxiliary Boiler	100.0	2.0	5,906	308
DGS	Diesel Emergency Generator	65.6	0.7	6,427	957
DFP	Diesel Fire Pump	45	0.4	1,404	840

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 July 13, 2000, with additional information received on February 7, 9, 14, March 29, and May 3, 2001.

Emissions Calculation

See Appendix (Emission Calculation Spreadsheets for detailed calculations (nine (9) 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. It also should be noted that the emission factors, heat input and heat content values are based on the higher heating value (HHV). The HHV includes the energy released by condensing the water formed in the combustion reaction.

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

Total Potential to Emit Emissions

The following table reflects the PTE before controls of the regulated pollutants from the proposed new source.

Pollutant	Potential Emissions (tons/year)	Permit Threshold Levels (tons/year)
Particulate Matter (PM)	336.47	25
Particulate Matter (PM_{10})	336.47	15
Sulfur Dioxide (SO_2)	181.92	40
Volatile Organic Compounds (VOC)	104.95	40
Carbon Monoxide (CO)	1477.24	100
Nitrogen Oxides (NO_X)	1564.17	40
Single HAP	4.18	10
Combination of HAPs	10.85	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.

County Attainment Status

The source is located in Lawrence 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. Lawrence 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) Lawrence County has been classified as attainment or unclassifiable for all criteria pollutants. 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):

Pollutant	Emissions (ton/yr)
PM	332.14
PM_{10}	332.14
SO_2	174.81
VOC	100.94
CO	1454.70
NO_X	439.38
Single HAP	4.01
Combination HAPs	10.66

(a) The NO_X emissions from the combustion turbine and duct burner will be controlled by a selective catalytic reduction (SCR) system and dry low-NO_X combustors.

(b) The 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 pollutant is greater than or equal to 100 tons per year,

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

The source submitted their Acid Rain application to the Office of Air Quality (OAQ) on December 8, 2000.

Federal Rule Applicability

40 CFR 60, Subpart GG (Stationary Gas Turbines)

The three (3) 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 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 three heat recovery steam generators (HRSG)/ duct burners (DB) are subject to 40 CFR Part 60, Subpart Da because the heat input capacity is greater than 250 MMBtu/hr. The HRSG DBs have a heat input capacity of 300 MMBtu/hr and are therefore subject to Subpart Da.

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

(a) Limit particulate matter (PM) emissions to 9.0 lb/hr during normal operation, as required by 40 CFR 60.42(a)

(b) 40 CFR 60.42a(b) sets the maximum opacity to twenty percent (20%) for a six (6) minute average, except for one six (6) minute period per hour of not more than twenty seven percent (27%).

(c) Limit NO_X emissions to 60 lb/hr during normal operation, as required by 40 CFR 60.44a(a)(1). Demonstration with the NSPS emission standard also demonstrates compliance with NO_X emissions reduction requirements, as stated in 40 CFR 60.44a(a)(2)

(d) A continuous monitoring system is required to record NO_X emissions form each duct burner (DB), as required by 40 CFR 60.47a(c).

(e) As required by 40 CFR 60.47a(d) continuous monitoring system must be installed to record oxygen (O_2) and carbon dioxide (CO_2) concentrations at each location where NO_x emissions are measured.

(f) The natural gas-fired duct burners, as required by 40 CFR 60.46a, are subject to the following:

(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 thirty (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 thirty (30) day average emission rate for both sulfur oxide 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 thirty (30) successive burner operating days. The initial performance test is the only test in which at least thirty (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 thirty (30) successive boiler operating days is completed within sixty (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.

(g) The duct burners are not subject to the opacity and sulfur dioxide (SO_2) emission monitoring, 40 CFR 60.47a(a) and (b) requirements because only natural gas fuel is combusted.

(h) The Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxide (NO_X) emissions discharged to the atmosphere, as required by 40 CFR 60.47a(c).

(i) The Permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring oxygen content of the flue gases at each location where sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions are monitored, as required by 40 CFR 60.47(d).

(j) The Permittee shall use as use Method 19 to determine the emission rate of NO_X, and the continuous monitoring system shall be used to determine concentrations of NO_X and O_2, as required by 40 CFR 60.48a.

(k) The Permittee, as required by 40 CFR 60.49a(Reporting Requirements), is subject to the following reporting requirements:

(1) NO_X performance test data from the initial performance test and from the performance evaluation of the continuous monitoring are submitted to the Administrator.

(2) Information required by 40 CFR 60.49a(b) from the NO_X 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 thirty (30) successive burner operating days.

(4) For any period in which nitrogen oxide (NO_X) emission data is 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) The Permittee shall submit a signed statement, as required by 40 CFR 60.49a(g) indicating whether:

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

(b) The data used to show compliance was of 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 of have not been met; or, the minimum data requirements have not been met for errors that where unavoidable.

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

(6) For the purpose of the reports required under 40 CFR 60.7, periods of excess emissions are defined as all six (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 dates 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 at 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.

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 is 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 after issuance of this permit, 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, OAQ upon request and shall be subject to review and approval by IDEM, 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 these modeling exercise.

326 IAC 2-4.1-1 (New Source Toxics Rule)

The New Source Toxics Control rule requires any new or reconstructed major source of hazardous air pollutants (HAPs) for which there are no applicable NESHAP to implement maximum achievable control technology (MACT), determined on a case-by-case basis, when the potential to emit is greater than 10 tons per year of any single HAP information on emissions of the 187 hazardous air pollutants (listed in the OAQ Construction Permit Application, Form Y) set out in the Clean Air Act Amendments of 1990. These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industry.

The New Source Toxic Rule is not applicable because no single HAP emission is greater than or equal to 10 tons per year and no combination HAP emissions is greater than or equal to 25 tons per year.

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, and NO_X because the potential to emit for these pollutants exceed 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 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).

The attached modeling analysis, included in 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.

The BACT Analysis Report, included in Appendix C, was conducted for the major source PSD pollutants for each process on a case-by-case basis by reviewing similar process controls and new available technologies. The BACT determination is based on the cost per ton of pollutant removed, energy requirements, and environmental impacts. The following BACT emission limitations apply to the proposed source:

Emission Unit	Emissions Limit and Basis				
	NOx	**CO**	**SO_2**	**VOC**	**TSP/PM_{10}**
Natural Gas-Fired Combustion Turbines with Duct Burners					
Emission Rate	3.0 ppmvd @ 15% O_2 (CTG & Ductburners)	12.2 ppmvd @ 15% O_2 (CTG & Ductburners) 9ppm (CTG only)	0.006 lbs/MMBtu	0.0037 lb/MMBtu @ 15%, O_2 (CTG & Ductburners)	0.014 lbs/MMBtu (CTG & Ductburners) 0.017 lb/MMBtu (CTG only)
Proposed BACT	DLNB Combustion & SCR	Good Combustion Practice /Design	Use of Very Low Sulfur Natural Gas	Good Combustion Practice/Design	Natural gas, and good combustion practices/ design
Natural Gas-Fired Auxiliary Boiler					
Emission Rate	0.08 lbs/MMBtu	0.082 lbs/MMBtu	0.006 lbs/MMBtu	0.011 lbs/MMBtu	0.02 lbs/MMBtu
Proposed BACT	Dry Low NOx Burner	Good combustion Practice/Design	Use of Very Low Sulfur Natural Gas	Good combustion Practice/Design	Good Combustion Practice/Design
Cooling Tower					
Emission Rate	N/A	N/A	N/A	N/A	3.43 lb/hr
Proposed BACT	N/A	N/A	N/A	N/A	Drift Eliminators

326 IAC 2-6 (Emission Reporting)

The proposed facility is subject to 326 IAC 2-6 (Emission Reporting) because at least one listed pollutant exceeds its emission threshold level, because the source will emit more than 100 tons per year for all criteria pollutants. Pursuant to this rule, the owner/operator of this facility must annually submit an emission statement of the facility. 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 1 and 2 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. To demonstrate compliance with the NO_X limit, the source shall take an average of the parts per million (ppm) at 15% O_2 over a three (3) block. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) 15% O_2 over a twenty four (24) hour 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 Alternative Opacity Limitations), 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 million Btu, upon request of OAQ.

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 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.

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 Appendix (Emission Calculation Spreadsheets for detailed calculations **(**nine (9) pages).

Conclusion

The construction of this combined cycle merchant power plant will be subject to the conditions of the attached proposed **Construction Permit No. CP-093-12432-00021.**

APPENDIX A - Combined Cycle Operation Emission Calculations
Combustion Turbine and Duct Burner Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat Input	**1944.10**	MMBtu/hr		
Combustion Turbine w/Duct Burner Heat input @ -10 F	**2244.10**	MMBtu/hr	Number of Turbines	**3**
Duct Burner Heat input @ 60 F	**300**	MMBtu/hr	Number of Duct Burners	**3**

	Normal Operation	**Startup/Shutdown**
Turbine Operation (hrs/yr)	**6290**	**2470**
Duct Burner Operation (hrs/yr)	**6290**	

Combustion Turbine/Duct Burner										
Pollutant	Heat Input		Emission Factor		lb/hr	PTE/CT		Total PTE		
NO_X	2244.1	MMBtu/hr	0.0618	lb/MMBtu	138.7	436.17	tons/yr	1308.50	tons/yr	
CO	2244.1	MMBtu/hr	0.0276	lb/MMBtu	62.2	195.49	tons/yr	586.48	tons/yr	
VOC	2244.1	MMBtu/hr	0.0034	lb/MMBtu	7.6	23.93	tons/yr	71.80	tons/yr	
SO_2	2244.1	MMBtu/hr	0.006	lb/MMBtu	13.2	41.64	tons/yr	124.92	tons/yr	
PM_{10}	2244.1	MMBtu/hr	0.011	lb/MMBtu	24.0	75.51	tons/yr	226.53	tons/yr	

Combustion Turbine									
Pollutant	Heat Input		Emission Factor		lb/hr	PTE/CT		Total PTE	
NO_X	**1944.10**	MMBtu/hr	0.0399	lb/MMBtu	77.6	243.96	tons/yr	731.87	tons/yr
CO	**1944.10**	MMBtu/hr	0.018	lb/MMBtu	35.0	110.06	tons/yr	330.17	tons/yr
VOC	**1944.10**	MMBtu/hr	0.0019	lb/MMBtu	3.6	11.45	tons/yr	34.34	tons/yr
SO_2	**1944.10**	MMBtu/hr	0.006	lb/MMBtu	11.7	36.67	tons/yr	110.01	tons/yr
PM_{10}	**1944.10**	MMBtu/hr	0.01028	lb/MMBtu	20.0	62.90	tons/yr	188.70	tons/yr

Combustion turbine emission factors are vendor provide data
Duct burner emission factors are from AP-42, Chapter 1.4

Duct Burner PTE is based on 8760 hrs/yr operation

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

Combustion Turbine/Duct Burner					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	2244.1 MMBtu/hr	0.01323 lb/MMBtu*	29.69	93.37 tons/yr	280.12 tons/yr
CO	2244.1 MMBtu/hr	0.0276 lb/MMBtu	62.16	195.49 tons/yr	586.48 tons/yr
VOC	2244.1 MMBtu/hr	0.0034 lb/MMBtu	7.61	23.93 tons/yr	71.80 tons/yr
SO_2	2244.1 MMBtu/hr	0.006 lb/MMBtu	13.24	41.64 tons/yr	124.92 tons/yr
PM_{10}	2244.1 MMBtu/hr	0.011 lb/MMBtu	24.01	75.51 tons/yr	226.53 tons/yr

Combustion Turbine			
Pollutant	Heat Input	Emission Factor	lb/hr
NO_X	Emission Fac MMBtu/hr	0.0133 lb/MMBtu*	25.86
CO	Emission Fac MMBtu/hr	0.018 lb/MMBtu	34.99
VOC	Emission Fac MMBtu/hr	0.0019 lb/MMBtu	3.69
SO_2	Emission Fac MMBtu/hr	0.006 lb/MMBtu	11.66
PM_{10}	Emission Fac MMBtu/hr	0.01028 lb/MMBtu	19.99

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

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

Startup/Shutdown Emissions

Combined Cycle Operation

Estimated max hours of startup per year	**1670**	Total Number of Cycles	**400**
Estimated max hours of shutdown per year	**800**		

Emissions from Combined Cycle Opeartion				
Pollutant	Startup Emission Rate (lb/start-up)	Shutdown Emission Rate (lb/start-up)	Emission Rate per Turbine (tons /yr)	Total Emission (tons/yr)
NO_X	212.7	35	49.54	148.62
CO	1174	261.5	287.10	861.30

(1) Startup and shutdown are defined for loads below 70% base load and are not expected to exceed 250 minutes for start-up and 2 hours for shutdown per turbine

(2) A cycle includes 1 startup and 1 shutdown. The maximum annual number of expected cycles is 400 per turbine.

(3) Calculated emissions are for a single turbine

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 (6290 hrs/yr)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE (6290 hrs/yr)	PTE (6290 hrs/yr,3 CT)	tons/yr
Benzene	2.06E-06	6.18E-04	1.94E-03	1.20E-05	2.33E-02	7.34E-02	2.20E-01	2.26E-01
Dichlorobenzene	1.18E-06	3.53E-04	1.11E-03					3.33E-03
Formaldehyde*	7.35E-05	2.21E-02	6.93E-02	1.10E-04	2.14E-01	6.73E-01	2.02E+00	2.23E+00
Xylenes				6.40E-05	1.24E-01	3.91E-01	1.17E+00	1.17E+00
Hexane	1.76E-03	5.29E-01	1.67E+00	2.52E-04	4.90E-01	1.54E+00	4.62E+00	9.62E+00
Ethylbenzene				3.20E-05	6.22E-02	1.96E-01	5.87E-01	5.87E-01
1,3 Butadiene				4.30E-07	8.36E-04	2.63E-03	7.89E-03	7.89E-03
Napthalene	5.98E-07	1.79E-04	5.64E-04	1.30E-06	2.53E-03	7.95E-03	2.38E-02	2.55E-02
Toluene	3.33E-06	1.00E-03	3.15E-03	1.30E-04	2.53E-01	7.95E-01	2.38E+00	2.39E+00
PAH				2.20E-06	4.28E-03	1.35E-02	4.04E-02	4.04E-02
POM	8.65E-08	2.59E-05	8.16E-05	8.65E-08	1.68E-04	5.29E-04	1.59E-03	1.83E-03
Acetaldehyde				4.00E-05	7.78E-02	3.41E-01	1.02E+00	1.02E+00
Arsenic	1.96E-07	5.88E-05	1.85E-04					5.55E-04
Beryllium	1.18E-08	3.53E-06	1.11E-05					3.33E-05
Cadmium	1.08E-06	3.24E-04	1.02E-03					3.05E-03
Chromium	1.37E-06	4.12E-04	1.30E-03					3.89E-03
Cobalt	8.24E-08	2.47E-05	7.77E-05					2.33E-04
Manganese	3.73E-07	1.12E-04	3.52E-04					1.05E-03
Mercury	2.55E-07	7.65E-05	2.41E-04					7.22E-04
Nickel	2.06E-06	6.18E-04	1.94E-03					5.83E-03
Selenium	2.35E-08	7.06E-06	2.22E-05					6.66E-05
	single HAP		5.00E+00				4.62E+00	9.62
	combined HAP		5.24E+00				1.21E+01	17.34

Natural Gas Utility Boiler Calculation

Auxiliary Boiler Heat Input Rate	35	MMBtu/hr	Number of Boilers	1
		Boiler Operation (hrs/yr)	3000	

Auxiliary Boiler									
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE		PTE after Control or Enforcable Limits	
NO_X	35	MMBtu/hr	8.00E-02	lb/MMBtu	2.800	12.264	ton/yr	4.200	ton/yr
CO	35	MMBtu/hr	8.20E-02	lb/MMBtu	2.870	12.571	ton/yr	4.305	ton/yr
VOC	35	MMBtu/hr	1.00E-02	lb/MMBtu	0.350	1.533	ton/yr	0.525	ton/yr
SO_2	35	MMBtu/hr	6.00E-03	lb/MMBtu	0.210	0.920	ton/yr	0.315	ton/yr
PM_{10}	35	MMBtu/hr	2.00E-02	lb/MMBtu	0.700	3.066	ton/yr	1.050	ton/yr

***Emission factors are vendor provided information**

***All of the emission factors used are higher than AP-42 emission factors listed in Table 1.4-1 and 1.4-2**

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE Before Control (tpy)	PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.00E-06	7.00E-05	3.07E-04	1.05E-04
Dichlorobenzene	1.20E-03	1.14E-06	4.00E-05	1.75E-04	6.00E-05
Formaldehyde	7.50E-02	7.14E-05	2.50E-03	1.10E-02	3.75E-03
Hexane	1.80E+00	1.71E-03	6.00E-02	2.63E-01	9.00E-02
Napthalene	6.10E-04	5.81E-07	2.03E-05	8.91E-05	3.05E-05
Toluene	3.40E-03	3.24E-06	1.13E-04	4.96E-04	1.70E-04
POM	8.87E-05	8.45E-08	2.96E-06	1.30E-05	4.44E-06
Arsenic	2.00E-04	1.90E-07	6.67E-06	2.92E-05	1.00E-05
Beryllium	1.20E-05	1.14E-08	4.00E-07	1.75E-06	6.00E-07
Cadmium	1.10E-03	1.05E-06	3.67E-05	1.61E-04	5.50E-05
Chromium	1.40E-03	1.33E-06	4.67E-05	2.04E-04	7.00E-05
Cobalt	8.40E-05	8.00E-08	2.80E-06	1.23E-05	4.20E-06
Manganese	3.80E-04	3.62E-07	1.27E-05	5.55E-05	1.90E-05
Mercury	2.60E-04	2.48E-07	8.67E-06	3.80E-05	1.30E-05
Nickel	2.10E-03	2.00E-06	7.00E-05	3.07E-04	1.05E-04
Selenium	2.40E-05	2.29E-08	8.00E-07	3.50E-06	1.20E-06
		Single HAP		**2.63E-01**	**9.00E-02**
		Combined HAP		**2.76E-01**	**9.44E-02**

*HAPs emission factors based on AP-42 1.4-3

Diesel Generator Calculation

Diesel Generator 8.4 MMBtu/hr Number of Generators 1

Generator Operation (hrs/yr) 500

Diesel Generator										
Pollutant	Heat Input		Emission Factor		lb/hr	Generator PTE		PTE after Control or Enforcable Limits	
NO_X	8.4	MMBtu/hr	2.08E+00	lb/MMBtu	17.472	76.527	ton/yr	4.368	ton/yr
CO	8.4	MMBtu/hr	3.90E-01	lb/MMBtu	3.276	14.349	ton/yr	0.819	ton/yr
VOC	8.4	MMBtu/hr	7.10E-02	lb/MMBtu	0.596	2.612	ton/yr	0.149	ton/yr
SO_2	8.4	MMBtu/hr	1.41E-01	lb/MMBtu	1.184	5.188	ton/yr	0.296	ton/yr
PM_{10}	8.4	MMBtu/hr	6.19E-02	lb/MMBtu	0.520	2.277	ton/yr	0.130	ton/yr

***Emission factors are vendor provided information**

***All of the emission factors used are higher than AP-42 emission factors listed in Table 1.4-1 and 1.4-2**

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE Before Control (tpy)	PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.00E-06	1.68E-05	7.36E-05	4.20E-06
Diclorobenzene	1.20E-03	1.14E-06	9.60E-06	4.20E-05	2.40E-06
Formaldehyde	7.50E-02	7.14E-05	6.00E-04	2.63E-03	1.50E-04
Hexane	1.80E+00	1.71E-03	1.44E-02	6.31E-02	3.60E-03
Napthalene	6.10E-04	5.81E-07	4.88E-06	2.14E-05	1.22E-06
Toluene	3.40E-03	3.24E-06	2.72E-05	1.19E-04	6.80E-06
POM	8.87E-05	8.45E-08	7.10E-07	3.11E-06	1.77E-07
Arsenic	2.00E-04	1.90E-07	1.60E-06	7.01E-06	4.00E-07
Beryllium	1.20E-05	1.14E-08	9.60E-08	4.20E-07	2.40E-08
Cadmium	1.10E-03	1.05E-06	8.80E-06	3.85E-05	2.20E-06
Chromium	1.40E-03	1.33E-06	1.12E-05	4.91E-05	2.80E-06
Cobalt	8.40E-05	8.00E-08	6.72E-07	2.94E-06	1.68E-07
Manganese	3.80E-04	3.62E-07	3.04E-06	1.33E-05	7.60E-07
Mercury	2.60E-04	2.48E-07	2.08E-06	9.11E-06	5.20E-07
Nickel	2.10E-03	2.00E-06	1.68E-05	7.36E-05	4.20E-06
Selenium	2.40E-05	2.29E-08	1.92E-07	8.41E-07	4.80E-08
		Single HAP		**6.31E-02**	**3.60E-03**
		Combined HAP		**6.62E-02**	**3.78E-03**

*HAPs emission factors based on AP-42 1.4-3

Fuel Preheater Calculation

Fuel Preheater	5	MMBtu/hr	Number of Preheaters	3
		Preheater Operation (hrs/yr)	8760	

Fuel Preheater									
Pollutant	Heat Input		Emission Factor		lb/hr	Preheater PTE		PTE after Control or Enforceable Limits (ton/yr)
NO_X	5	MMBtu/hr	5.00E-02	lb/MMBtu	0.250	1.095	ton/yr	1.095
CO	5	MMBtu/hr	8.00E-02	lb/MMBtu	0.400	1.752	ton/yr	1.752
VOC	5	MMBtu/hr	1.10E-02	lb/MMBtu	0.055	0.241	ton/yr	0.241
SO_2	5	MMBtu/hr	6.00E-03	lb/MMBtu	0.030	0.131	ton/yr	0.131
PM_{10}	5	MMBtu/hr	2.00E-02	lb/MMBtu	0.100	0.438	ton/yr	0.438

***Emission factors are vendor provided information**

***All of the emission factors used are higher than AP-42 emission factors listed in Table 1.4-1 and 1.4-2**

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE Before Control (tpy)	PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.00E-06	1.00E-05	4.38E-05	1.31E-04
Diclorobenzene	1.20E-03	1.14E-06	5.71E-06	2.50E-05	7.51E-05
Formaldehyde	7.50E-02	7.14E-05	3.57E-04	1.56E-03	4.69E-03
Hexane	1.80E+00	1.71E-03	8.57E-03	3.75E-02	1.13E-01
Napthalene	6.10E-04	5.81E-07	2.90E-06	1.27E-05	3.82E-05
Toluene	3.40E-03	3.24E-06	1.62E-05	7.09E-05	2.13E-04
POM	8.87E-05	8.45E-08	4.22E-07	1.85E-06	5.55E-06
Arsenic	2.00E-04	1.90E-07	9.52E-07	4.17E-06	1.25E-05
Beryllium	1.20E-05	1.14E-08	5.71E-08	2.50E-07	7.51E-07
Cadmium	1.10E-03	1.05E-06	5.24E-06	2.29E-05	6.88E-05
Chromium	1.40E-03	1.33E-06	6.67E-06	2.92E-05	8.76E-05
Cobalt	8.40E-05	8.00E-08	4.00E-07	1.75E-06	5.26E-06
Manganese	3.80E-04	3.62E-07	1.81E-06	7.93E-06	2.38E-05
Mercury	2.60E-04	2.48E-07	1.24E-06	5.42E-06	1.63E-05
Nickel	2.10E-03	2.00E-06	1.00E-05	4.38E-05	1.31E-04
Selenium	2.40E-05	2.29E-08	1.14E-07	5.01E-07	1.50E-06
		Single HAP		**3.75E-02**	**1.13E-01**
		Combined HAP		**3.94E-02**	**1.18E-01**

*HAPs emission factors based on AP-42 1.4-3

Diesel Fire Pump Calculation

Diesel Fire Pump 2 MMBtu/hr Number of Pumps 1

Pump Operation (hrs/yr) 500

Diesel Fire Pump									
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE		PTE after Control or Enforcable Limits	
NO_X	2	MMBtu/hr	1.96E+00	lb/MMBtu	3.920	17.170	ton/yr	0.980	ton/yr
CO	2	MMBtu/hr	9.00E-02	lb/MMBtu	0.180	0.788	ton/yr	0.045	ton/yr
VOC	2	MMBtu/hr	6.50E-02	lb/MMBtu	0.130	0.569	ton/yr	0.033	ton/yr
SO_2	2	MMBtu/hr	1.95E-01	lb/MMBtu	0.390	1.708	ton/yr	0.098	ton/yr
PM_{10}	2	MMBtu/hr	2.00E-02	lb/MMBtu	0.040	0.175	ton/yr	0.010	ton/yr

***Emission factors are vendor provided information**

***All of the emission factors used are higher than AP-42 emission factors listed in Table 1.4-1 and 1.4-2**

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE Before Control (tpy)	PTE After Control or Enforceable Limit (tpy)
Benzene	2.10E-03	2.00E-06	4.00E-06	1.75E-05	1.00E-06
Diclorobenzene	1.20E-03	1.14E-06	2.29E-06	1.00E-05	5.71E-07
Formaldehyde	7.50E-02	7.14E-05	1.43E-04	6.26E-04	3.57E-05
Hexane	1.80E+00	1.71E-03	3.43E-03	1.50E-02	8.57E-04
Napthalene	6.10E-04	5.81E-07	1.16E-06	5.09E-06	2.90E-07
Toluene	3.40E-03	3.24E-06	6.48E-06	2.84E-05	1.62E-06
POM	8.87E-05	8.45E-08	1.69E-07	7.40E-07	4.22E-08
Arsenic	2.00E-04	1.90E-07	3.81E-07	1.67E-06	9.52E-08
Beryllium	1.20E-05	1.14E-08	2.29E-08	1.00E-07	5.71E-09
Cadmium	1.10E-03	1.05E-06	2.10E-06	9.18E-06	5.24E-07
Chromium	1.40E-03	1.33E-06	2.67E-06	1.17E-05	6.67E-07
Cobalt	8.40E-05	8.00E-08	1.60E-07	7.01E-07	4.00E-08
Manganese	3.80E-04	3.62E-07	7.24E-07	3.17E-06	1.81E-07
Mercury	2.60E-04	2.48E-07	4.95E-07	2.17E-06	1.24E-07
Nickel	2.10E-03	2.00E-06	4.00E-06	1.75E-05	1.00E-06
Selenium	2.40E-05	2.29E-08	4.57E-08	2.00E-07	1.14E-08
		Single HAP		**1.50E-02**	**8.57E-04**
		Combined HAP		**1.58E-02**	**8.99E-04**

*HAPs emission factors based on AP-42 1.4-3

Cooling Tower Emissions

Big Tower (Cells 1-4)

	Value	Unit	Calculation
Flow of Water at 100% Load	84000	gpm	vendor information
Cooling Water Flowrate	42033600	lb/hr	Flowrate (gal/min) * 8.34 lb/gal * 60 min/hr
Total Disolved Solids (TDS)	4080	ppm	vendor information
Cooling Water TDS Fraction	0.00408	lb TDS/lb	$TDS/10^6$ lb/ppm
Drift Loses (% of cooling water)	0.002	%	vendor information
Liquid Drift Losses	840.672	lb/hr	Cooling water flow rate lb/hr * 0.002/100
Solids Drift Losses	3.430	lb/hr	Liquid Drift Losses * TDS Fraction lb TDS/lb
PM_{10}/TSD Emission	15.023	ton/yr	

Appendix A: Emission Calculations

Company Name: Cogentric Lawrence County, LLC
Address: Rural Route 3, Mitchell, IN 47446
Consruction Permit No.: CP-093-12432-00021
Permit Reviewer: Sherry Harris

Summary

PTE Before Controls								
Pollutant	Turbine/DB	Startup	Boiler	Fuel Preheater	Cooling Tower	Emergency Generator	Fire Pump	Total
NOx	1308.50	148.62	12.26	1.10	NA	76.53	17.17	1564.17
CO	586.48	861.30	12.57	1.75	NA	14.35	0.79	1477.24
VOC	100.00	NA	1.53	0.24	NA	2.61	0.57	104.95
SO2	173.97	NA	0.92	0.13	NA	5.19	1.71	181.92
PM/PM10	315.49	NA	3.07	0.44	15.02	2.28	0.18	336.47
Single HAP	3.83E+00	NA	2.63E-01	3.75E-02	NA	6.31E-02	1.50E-02	4.21
Combined HAP	1.05E+01	NA	2.76E-01	3.94E-02	NA	6.62E-02	1.58E-02	10.88

PTE After Controls								
Pollutant	Turbine/DB	Startup	Boiler	Fuel Preheater	Cooling Tower	Diesel Generator	Fire Pump	Total
NOx	280.12	148.62	4.20	1.10	NA	4.37	0.98	439.38
CO	586.48	861.30	4.31	1.75	NA	0.82	0.05	1454.70
VOC	100.00	NA	0.53	0.24	NA	0.15	0.03	100.94
SO2	173.97	NA	0.32	0.13	NA	0.30	0.10	174.81
PM/PM10	315.49	NA	1.05	0.44	15.02	0.13	0.01	332.14
Single HAP	3.83E+00	NA	9.00E-02	3.75E-02	NA	6.31E-02	1.50E-02	4.04
Combined HAP	1.05E+01	NA	9.44E-02	3.94E-02	NA	6.62E-02	1.58E-02	10.70

Duct Burners are not subject to MACT applicability, therefore the Single HAP and Combined HAP data will come from the turbines only, instead of turbine and associated duct burner.

Appendix B - Air Quality Analysis

Introduction

Cogentrix Lawrence County, LLC (Cogentrix) has applied for a Prevention of Significant Deterioration (PSD) permit to construct and operate a combined cycle electric power generation facility southeast of Bedford in Lawrence County, Indiana. The site is located at Universal Transverse Mercator (UTM) coordinates 547044.4 East and 4294455.8 North. The facility would consist of a nominal 820-megawatt combined cycle, natural gas-fired electric power generation plant. There will be three combined cycle combustion turbine generators with duct burners, three heat recovery steam generators, one natural gas-fired auxiliary boiler, portable emergency diesel generators, diesel fire pump, cooling towers and ancillary equipment. Lawrence County is designated as attainment for the National Ambient Air Quality Standards. These standards for Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Carbon Monoxide (CO) and Particulate Matter less than 10 microns (PM_{10}) are set by the United States Environmental Protection Agency (U.S. EPA) to protect the public health and welfare.

Malcolm-Pirnie Inc prepared the PSD permit application for Cogentrix. The Office of Air Management (OAQ) on July 3, 2000 received the original permit application. This document provides OAQ's Air Quality Modeling Section's review of the PSD permit application and air quality analysis.

Air Quality Analysis Objectives

The OAQ review of the air quality impact analysis portion of the permit application will accomplish the following objectives:

A. Establish which pollutants require an air quality analysis based on source emissions.
B. Determine the ambient air concentrations of the source's emissions and provide analysis of actual stack height with respect to Good Engineering Practice (GEP).
C. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or Prevention of Significant Deterioration (PSD) increment.
D. Perform an analysis of any air toxic compound for the health risk factor on the general population.
E. Perform a brief qualitative analysis of the source's impact on general growth, soils, vegetation, endangered species 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 171 kilometers (106 miles), from the Cogentrix site near Bedford, Indiana.

Summary

Cogentrix has applied for a PSD construction permit to construct and operate a combined cycle electric generation plant facility near Bedford in Lawrence County, Indiana. The PSD application was prepared by Malcolm-Pirnie, Inc. of Newport, Virginia. Lawrence County is currently designated as attainment for all criteria pollutants. Emission rates of five pollutants (Carbon Monoxide (CO), Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Particulate Matter less than 10 microns (PM_{10}) and Volatile Organic Compounds (VOCs)) associated with the facility exceeded significant emission rates established in state and federal law, thus requiring air quality modeling. Modeling results taken from the Industrial Source Complex Short Term (ISCST3) model showed all pollutant impacts for CO, SO_2, PM_{10} and NO_2 were predicted to be below the significant impact for purposes of a National Ambient Air Quality Standards analysis. OAQ conducted Hazardous Air Pollutant (HAPs) modeling and all HAP 8-hour maximum concentrations modeled below 0.5% of each Permissible Exposure Limit (PEL). There was no impact review conducted for the nearest Class I area, which is Mammoth Cave National Park in Kentucky. No Class I analysis is required if a source is located more than 100 kilometers (61 miles) from the nearest Class I area. An additional impact analysis on the surrounding area was conducted and no significant impact on economic growth, soils, vegetation, federal and state endangered species or visibility from the Cogentrix was expected.

Part A - Pollutants Analyzed for Air Quality Impact

Indiana Administrative Code (326 IAC 2-2) PSD requirements apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a new major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1. CO, NO_x, SO_2, VOCs and PM_{10} will be emitted from Cogentrix and an air quality analysis is required for CO, NO_x, SO_2, VOCs and PM_{10}, all of which exceeded their significant emission rates as shown in Table 1. It should be noted that all emissions are based on the Best Available Control Technology (BACT) determination and other limitations resulting from the OAQ review of the application.

TABLE 1 – Cogentrix's Significant Emission Rates (tons/yr)

Pollutant	Maximum Allowable Emissions	Significant Emission Rate
CO	830.3	100.0
NO_x	604.1	40.0
SO_2	175.1	40.0
PM_{10}	364.4	15.0
VOC (ozone)	102.0	40.0

Significant emission rates are established to determine whether a source is required to conduct an air quality analysis. If a source exceeds the significant emission rate for a pollutant, air dispersion modeling is required for that specific pollutant. A modeling analysis for each pollutant is conducted to determine whether the modeled concentrations would exceed significant impact increments. Modeled concentrations below significant impact increments are not required to conduct further air quality modeling. Modeled concentrations exceeding the significant impact increment would be required to conduct more refined modeling which would include source inventories and background data. These procedures are defined in "Guidelines for Air Quality Maintenance Planning and Analysis, Volume 10, Procedures for Evaluating Air Quality Impacts of New Stationary Sources@ October 1977, U.S. EPA Office of Air Quality Planning and Standards (OAQPS).

Part B - Significant Impact Analysis

An air quality analysis, including air dispersion modeling, was performed to determine the maximum concentrations of the source emissions on receptors outside of the facility property lines. A worst-case approach for emission estimates has been taken due to the nature of the operational capability of the facility. Normal operating loads of 100 percent at four ambient air temperatures of -10^o F, 30^o F, 80^o F and 105^o F for natural gas-firings and 70 percent load at ambient air temperature of 72^o F was modeled. Emission rates and modeling results for each worst-case determination per unit can be found in Appendix A and the modeled emission rates include the start-up and shutdown emissions are listed in Appendix B.

Model Description

The Office of Air Management review used the Industrial Source Complex Short Term (ISCST3) model, Version 3, dated April 10, 2000 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the United States Environmental Protection Agency (U.S. EPA) approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W AGuideline on Air Quality Models@. The Auer Land Use Classification scheme was referred to determine the land use in a 3 kilometer (1.9 miles) radius from the source. The area is considered primarily agricultural and forest, therefore a rural classification was used. The model also utilized the Schulman-Scire algorithm to account for building downwash effects. The stacks associated with the proposed facility are below the

Good Engineering Practice (GEP) formula for stack heights. This indicates wind flow over and around surrounding buildings can influence the dispersion of concentrations coming from the stack.

326 IAC 1-7-3 requires a study to demonstrate that excessive modeled concentrations will not result from stacks with heights less than the GEP stack height formula. These aerodynamic downwash parameters were calculated using U.S. EPA=s Building Profile Input Program (BPIP).

Meteorological Data

The meteorological data used in the ISCST3 model consisted of the latest five years of available surface data from the Louisville, Kentucky National Weather Service station merged with the mixing heights from Peoria, Illinois Airport National Weather Service station. The 1990-1994 meteorological data was purchased through the National Oceanic and Atmospheric Administration (NOAA) and National Climatic Data Center (NCDC) and preprocessed into ISCST3-ready format with U.S. EPA=s PCRAMMET.

Receptor Grid

Ground-level points (receptors) surrounding the source are input into the model to determine the maximum modeled concentrations that would occur at each point. OAQ modeling utilized a coarse Cartesian receptor grid out to 20 kilometers (10.25 miles) for all pollutants with receptor spaced at distances of 1000 meters (3280 feet). Two fine receptor grids with receptors spaced at distances of 100 meters (328 feet) were place, one grid out 5 kilometers from the source and the second centered approximately 3.5 kilometers north northeast from the site. Discrete receptors were placed 50 meters or 164 feet apart on Cogentrix property lines and also at the location of areas with sensitive groups (schools or hospitals).

Modeled Results

Maximum modeled concentrations for each pollutant over its significant emission rate are listed below in Table 3 and are compared to each pollutant=s significant impact increment for Class II areas, as specified by U.S. EPA in the Federal Register, Volume 43, No. 118, pg 26398 (Monday, June 19, 1978).

TABLE 3 - Summary of OAQ Significant Impact Analysis (ug/m3)

Pollutant	Year	Time-Averaging Period	Cogentrix Maximum Modeled Impacts	Significant Impact Increments	Significant Monitoring Levels
CO	1987	1-hour	681.6	**2000.0**	[a]
CO	1986	8-hour	222.8	**500.0**	575.0
NO_2	1987	Annual - 8760 hrs/yr	0.85	**1.0**	14.0
SO_2	1987	3-hour	23.3	**25.0**	[a]
SO_2	1990	24-hour	2.7	**5.0**	13.0
SO_2	1990	Annual - 8760 hrs/yr	0.24	**1.0**	[a]
PM_{10}	1990	24-hour	4.997	**5.0**	10.0
PM_{10}	1988	Annual - 8760 hrs/yr	0.45	**1.0**	[a]

[a] No limit exists for this time-averaged period

All modeled concentrations for each pollutant at all applicable time-averaged periods were below both the significant impact increment and significant monitoring de minimis levels. No excessive concentrations will result due to stack heights less than the GEP stack height formula. Existing air quality concentrations as recorded by monitors throughout the area are below National Ambient Air Quality Standards for each pollutant. No significant short-term or long-term health impacts are expected as a result of the proposed facility and no further refined air quality analysis is required as well as no pre-construction monitoring requirements. Due to the PM_{10} significant impacts coming within 0.003 ug/m3 of the significance level, OAQ has conducted refined modeling using the modeling methodology mentioned above to compare the air quality impacts to the NAAQS and PSD increments for PM_{10}.

Emission inventories of PM_{10} sources in Indiana within a 50 kilometer radius of the Cogentrix site were taken from the OAQ emission statement database as required by 326 IAC 2-6. OAQ modeling results are shown in Table 4. All maximum concentrations of PM_{10} for the 24-hour and annual time-averaged periods were below their respective NAAQS limit and further modeling was not required.

TABLE 4 - National Ambient Air Quality Standards Analysis (ug/m3)						
Pollutant	**Year**	**Time-Averaging Period**	**Modeled Source Impacts**	**Background**	**Total**	**NAAQS Limits**
PM_{10}	1991	Highest 2nd high 24-hour	61.0	51.3	112.3	150.0
PM_{10}	1991	Annual	6.0	28.0	34	50.0

Maximum allowable increases (PSD increments) are established by 326 IAC 2-2 for NO_2, SO_2 and PM_{10}. This rule limits a source to no more than 80 percent of the available PSD increment to allow for future growth. Since the significant impacts from Cogentrix for PM_{10} were modeled within 0.003 ug/m3 of the 24-hour PM_{10} significant impact increment, a PSD increment analysis for the existing major sources in Lawrence County and its surrounding counties was required. The PSD minor source baseline dates in Lawrence County for PM_{10} will be established with the Cogentrix application submittal date of July 3, 2000. 326 IAC 2-2-6 describes the availability of PSD increment and maximum allowable increases as Aincreased emissions caused by the proposed major PSD source ... will not exceed 80% of the available maximum allowable increases over the baseline concentrations for sulfur dioxide, particulate matter and nitrogen dioxide...@. Table 5 shows the results of the PSD increment analysis for PM_{10}. No violations of 80 percent of the PSD increment for PM_{10} occurred and no further modeling was required.

TABLE 5 - Prevention of Significant Deterioration Analysis (ug/m3)					
Pollutant	**Year**	**Time-Averaging Period**	**Modeled Concentrations**	**PSD Increment**	**Impact on PSD Increments**
PM_{10}	1994	Highest 2nd high 24-hour	13.5	30.0	45.0%
PM_{10}	1994	Annual	2.6	17.0	15.3%

Particulate Matter less than 2.5 micron

U.S. EPA issued a new National Ambient Air Quality Standard for Particulate Matter less than 2.5 microns ($PM_{2.5}$) on July 17, 1997. Due to a legal challenge to the new standard, however, U.S. EPA has released specific guidance stating that states should continue to analyze PM_{10} impacts for all New Source Review. There are 3 primary origins of $PM_{2.5}$: 1) primary particulates in the solid state, 2) condensible particulates and 3) secondary particulates formed through atmospheric reactions of gaseous precursor emissions. There will be a five-year scientific review of this standard which includes installation of $PM_{2.5}$ monitors throughout the state to better define background concentrations and gather source specific information. U.S. EPA is expected to release a new dispersion model to better predict $PM_{2.5}$ concentrations. There is no assumed ratio of $PM_{2.5}$ to PM_{10} at this time. As more information becomes available, a more detailed analysis of $PM_{2.5}$ can be conducted.

Part C - Ozone Impact Analysis

Ozone formation tends to occur in hot, sunny weather when NOx and VOC emissions photochemically react to form ozone. Many factors such as light winds, hot temperatures and sunlight are

necessary for higher ozone production. As per OAQ instruction, Malcolm-Pirnie submitted its own ozone transport analysis in the Cogentrix submittal. This included a wind rose analysis and a Reactive Plume Model (RPM-IV), which Malcolm-Pirnie has used in previous ozone analysis for other projects. The results of the wind rose analysis and the RPM-IV show that any potential plume emitted from the facility would fall out to the northeast and result in small ozone impacts.

OAQ Three-Tiered Ozone Review

OAQ incorporates a three-tiered approach in evaluating ozone impacts from a single source. The first step is to determine how NOx and VOC emissions from the new source compare to area-wide NOx and VOC emissions from Lawrence County as well as the surrounding counties of Greene, Jackson, Martin, Monroe, Orange and Washington Counties. Results from this analysis show Cogentrix=s 604.1 tons/yr of NOx would comprise 1% of the area-wide NOx emissions from point, area, onroad and nonroad mobile source and biogenic (naturally-occurring emissions from trees, grass and plants) emissions. Cogentrix=s 104 tons/yr of VOC emissions would comprise less than 1% of the area-wide VOC emissions from the different emission sources listed above.

A second step is to review historical monitored data to determine ozone trends for an area and the applicable monitored value assigned to an area for designation determinations. This value is known as the design value for an area. The nearest ozone monitors within this region is the Trafalgar monitor in Johnson County, which is 73.5 kilometers or 45.6 miles to the northeast of Cogentrix and is considered upwind of the facility. The design value for the Trafalgar monitor for the 1-hour ozone standard over the latest three years of monitoring data is 105 parts per billion (ppb). Wind rose analysis indicates that prevailing winds in the area occur from the southwest and west-southwest during the summer months of May through September when ozone formation is most likely to occur. Ozone impacts from the Cogentrix facility would likely fall north, northeast and east northeast of Cogentrix.

A third step in evaluating the ozone impacts from a single source is to estimate the source individual impact through a screening procedure. The Reactive Plume Model-IV (RPM-IV) has been used in past air quality reviews to determine 1-hour ozone impacts from single VOC/NOx source emissions. RPM-IV is listed as an alternative model in Appendix B to the 40 Code of Federal Register Part 51, Appendix W AGuideline on Air Quality Models@. The model is unable to simulate all meteorological and chemistry conditions present during an ozone episode (period of days when ozone concentrations are high). Results from RPM-IV are an estimation of potential ozone impacts. Modeling for 1 hour ozone concentrations was conducted for June 18, 1994 (a high ozone day) to compare to the ozone National Ambient Air Quality Standard (NAAQS) limit. The maximum cell concentration of ozone for each time and distance specified was used to compare to the ambient ozone. OAQ modeling results assumed the short-term emission rates of NO_2 and VOCs and are shown in Appendix A. The impact (difference between the plume-injected and ambient modes) from Cogentrix was 2.1 ppb early in the plume development. All ambient plus plume-injected modes were below the NAAQS limit for ozone at every time period and every distance. No modeled 1-hour NAAQS violations of ozone occurred.

Urban Airshed Model (UAM) analysis for regional ozone transport has been conducted by OAQ as well as states surrounding Lake Michigan and various national organizations. UAM is regarded as a regional modeling tool used to develop ozone attainment demonstrations and determine NOx and VOC emission controls for a region. Transport of ozone and ozone-forming pollutants from upwind areas is evident and likely contribute to increased ozone concentrations in Lawrence County. Previous experience with this model has shown that the amount of additional NOx and VOC emissions from Cogentrix, which are a tiny fraction of the pollutants regionally, would not noticeably increase the ozone concentrations in the area.

From this three-tiered approach, ozone formation is a regional issue and the emissions from Cogentrix will represent a small fraction of NOx and VOC emissions in the area. Ozone contribution from Cogentrix emissions is expected to be minimal. Ozone historical data shows that the area monitors have design values below the ozone NAAQS of 120 ppb and the Cogentrix ozone impact based on the emissions and modeling will have minimal impact on ozone concentrations in the area.

Part D - Hazardous Air Pollutant Analysis and Results

As part of the air quality analysis, OAQ requests data concerning the emission of 188 Hazardous Air Pollutants (HAPs) listed in the 1990 Clean Air Act Amendments which are either carcinogenic or otherwise considered toxic. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Management construction permit application Form Y. Any HAP emitted from a source will be subject to toxic modeling analysis. The modeled emissions for each HAP are the total emissions, based on assumed operation of 8760 hours per year.

OAQ performed toxic modeling using the ISCST3 model for all HAPs. Maximum 8-hour concentrations were determined and the concentrations were recorded as a percentage of each HAP Permissible Exposure Limit (PEL). The PELs were established by the Occupational Safety and Health Administration (OSHA) and represent a worker=s exposure to a pollutant over an 8-hour workday or a 40-hour workweek. In Table 6 below, the results of the HAP analysis with the emission rates, modeled concentrations and the percentages of the PEL for each HAPs are listed. All HAP concentrations were modeled below 0.5% of their respective PEL. The 0.5% of the PEL represents a safety factor of 200 taken into account when determining the health risk of the general population.

TABLE 6 - Hazardous Air Pollutant Analysis

Hazardous Air Pollutants	Total HAP Emissions	Limited HAP Emissions	Maximum 8-hour concentrations	PEL	Percent of PEL
	(tons/year)	(tons/year)	(ug/m3)	(ug/m3)	(%)
Acetaldehyde	0.31	0.901826	0.0155	360000.0	0.000004
Acrolein	0.18	0.087900	0.00146	250.0	0.000584
Benzene	4.1	1.621005	0.027	3200.0	0.000844
Formaldehyde	13.14	2.083333	0.0347	930.0	0.003731
Naphthalene	0.7	1.621005	0.027	50000.0	0.000054
Phosphorus	1.58	0.336758	0.00558	100.0	0.000002
Toluene	1.49	1.39	0.0231	750000.0	0.000003
Xylene	1.0	0.302511	0.00501	435000.0	0.000001
Metallic Hazardous Air Pollutants					
Antimony	0.13	0.000571	0.000009	500.0	0.000093
Arsenic	0.03	0.000571	0.000009	10.0	0.000093
Beryllium	0.0018	0.000571	0.000009	2.0	0.000093
Cadmium	0.022	0.009703	0.000159	5.0	0.00318
Chromium	0.26	0.015126	0.000252	500.0	0.00005
Cobalt	0.044	0.000571	0.000009	100.0	0.000093
Lead	0.31	0.185217	0.00308	50.0	0.00616
Manganese	1.8	0.01855	0.000308	5000.0	0.000006
Mercury	0.0044	0.004852	0.000084	100.0	0.000084

Nickel	6.3	0.000571	0.000009	1000.0	0.000093
Polycyclic Organic Matter	0.44	0.000571	0.000009	---	0.000093
Selenium	0.026	0.000571	0.000009	200.0	0.000093

[a] No OSHA PEL for 8-hour exposure exists at this time

Part E - Additional Impact Analysis

PSD regulations require additional impact analysis be conducted to show that impacts associated with the facility would not adversely affect the surrounding area. The Cogentrix PSD permit application provided an additional impact analysis performed by Malcolm-Pirnie. This analysis included an impact on economic growth, soils, vegetation and visibility and is listed in Section 7 of their application.

Economic Growth and Impact of Construction Analysis

A construction workforce of 200 is expected and Cogentrix will employ up to 20 people selected from the local and regional area once the facility is operational. Secondary emissions are not expected to significantly impact the area as all roadways will be paved. Industrial and residential growth is predicted to have negligible impact in the area since it will be dispersed over a large area and new home construction is not expected to significantly increase. Any commercial growth, as a result of the proposed facility, will occur at a gradual rate and will be accounted for in the background concentration measurements from air quality monitors. A minimal number of support facilities will be needed. There will be no adverse impact in the area due to industrial, residential or commercial growth.

Soils Analysis

Secondary NAAQS limits were established to protect general welfare, which includes soils, vegetation, animals and crops. Soil types in Lawrence County are of the Nolin-Alvin-Bloomfield and Crider-Frederick-Bedford Associations (Soil Survey of Lawrence County, U.S. Department of Agriculture). The general landscape consists of Mitchell Plain or gently rolling terrain (1816-1966 Natural Features of Indiana - Indiana Academy of Science). According to the modeled concentrations of CO, SO_2, NO_2 and PM_{10} and the HAPs analysis, the soils will not be adversely affected by the facility.

Vegetation Analysis

Due to the agricultural nature of the land, crops in the Lawrence County area consist mainly of corn, soybeans, hay, wheat and oats (1997 Agricultural Census for Lawrence County). The maximum modeled concentrations of Cogentrix for SO_2, NO_2 and PM_{10} are well below the threshold limits necessary to have adverse impacts on surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishopscap and horsetail milkweed (Flora of Indiana - Charles Deam). Livestock in Lawrence County consist mainly of beef and milk cows, hogs, chickens and sheep (1997 Agricultural Census for Lawrence County) and will not be adversely impacted from the facility. Trees in the area are mainly Beech, Maple, Oak and Hickory. These are hardy trees and due to the modeled concentrations, no significant adverse impacts are expected.

Federal and State Endangered Species Analysis

Federally endangered or threatened species as listed in the U.S. Fish and Wildlife Service , Division of Endangered Species for Indiana include 12 species of mussels, 4 species of birds, 2 species of bat and butterflies and 1 species of snake. The agricultural nature of the land overall has disturbed the habitats of the butterflies and snake and the proposed facility is not expected to impact the area further. The mussels and birds listed are commonly found along major rivers and lakes while the bats are found near caves. The ring pink mussels have been identified as endangered species in Lawrence County. The air impacts from Cogentrix's proposed facility are not expected to adversely impact this species.

Federally endangered or threatened plants as listed in 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 on cultivated or grazing land. The proposed facility is not expected to impact the area further.

The state of Indiana list of endangered, special concern and extirpated nongame species, as listed in the Department of Natural Resources, Division of Fish and Wildlife, contains species of birds, amphibians, fish, mammals, mollusks and reptiles which may be found in the area. However, the air impacts are not expected to have any additional adverse effects on the habitats of the species in the area.

Additional Analysis Conclusions

The nearest Class I area to Cogentrix is the Mammoth Cave National Park located approximately 171 km southeast in Kentucky. The proposed facility will not adversely affect the visibility at this Class I

area. Cogentrix is located well beyond 100 kilometers from Mammoth Cave National Park and will not have significant impact on the Class I area. The results of the additional impact analysis conclude the Cogentrix 's proposed facility will have no adverse impact on economic growth, soils, vegetation, endangered or threatened species or visibility on any Class I area.

APPENDIX A - RPM-IV Modeling for Cogentrix

NAAQS Analysis for Ozone (DATE)

Time	**Distance**	**Ambient**	**Plume-Injected**	**Source Impact**
(hours)	(meters)	(ppb)	(ppb)	(ppb)
700.0	116.0	34.6	35.8	1.2
800.0	5060.0	53.5	21.2	-32.3
900.0	13000.0	71.3	60.3	-11
1000.0	27000.0	87.4	78.9	-8.5
1100.0	39600.0	101	93.1	-7.9
1200.0	55600.0	112	106	-6
1300.0	74400.0	119	117	-2
1400.0	93900.0	122	121	-1
1500.0	114000.0	124	122	-2
1600.0	432000.0	124	122	-2
1700.0	150000.0	124	122	-2
1800.0	163000.0	124	122	-2
1900.0	169000.0	124	122	-2

APPENDIX C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) Review

Source Name:	Cogentrix Lawrence County, LLC
Source Location:	Rural Route 3, Mitchell, IN 47885
County:	Lawrence
Construction Permit No.:	CP-093-12432-00021
SIC Code:	4911
Permit Reviewer:	Sherry Harris

The Office of Air Quality (OAQ) has performed the following federal Best Available Control Technology (BACT) review for the proposed 820 megawatt (MW) natural gas combined cycle electric generating power facility named the Lawrence County Power Project (LCPP), to be owned and operated by Cogentrix Lawrence County, LLC. The review was performed for the three natural gas combustion turbines, one auxiliary boiler, one emergency diesel generator, one diesel fire pump, and three natural gas-fired pre-heaters.

The source is located in Lawrence County, which is designated as attainment or unclassifiable for all criteria pollutants (VOC, NO_X, CO, PM_{10}, and $S0_2$). 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 Manual*, 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.

Cogentrix has proposed the construction of the facility be completed in one phase. 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 A10 model steam turbine. Each combustion turbine will have an associated duct burner. Duct burners will be used for power augmentation.

Combined Cycle Best Available Control Technology (BACT)

(A) Three Natural Gas-Fired Combustion Turbines with Duct Burners

The three combustion turbines at the proposed Cogentrix Lawrence County, 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 2,244 MMBtu/hr on a higher 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 provide supplemental heat to produce high-pressure steam, which will then power the steam turbine to produce electricity, and will operate 8,760 hrs/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. Total suspended particulates (TSP) and particulate matter less than 10 micrometer (PM_{10}) will occur from the combustion of natural gas. The EPA's AP-42 considers particulate matter from natural gas combustion to be less than 1 micron, so all emissions are considered as PM_{10}. The PM_{10} emissions from the combustion of natural gas will result primarily from inert solids contained in the unburned fuel hydrocarbons, which agglomerate to form particles.

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:

Natural Gas Combustion and Good Combustion Practices
Baghouse (Fabric Filter)
Cyclone

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 Cogentrix Facility	Turbine (7FA)	2244	0.014	Good Combustion
Selkirk Cogen, NY	Turbine (7FA)	1173	0.004	Good Combustion
Auburndale Power Partners. LP, FL	Turbine (7FA)	1214	0.0136	Good Combustion
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)

Based on the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbine with duct burners on.

PM10 emission rates from natural gas combustion are inherently low because of very high combustion efficiencies and the clean burning nature of natural gas. Therefore, use of natural gas is in and of itself a highly efficient method of minimizing emissions.

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.

Again 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 a low ash fuel and efficient combustion. This BACT choice will meet any reasonable opacity standard. Typically, plume opacity is not an issue for this type of facility as the exhaust plumes are nearly invisible except for the condensation of moisture during periods of low ambient temperature. There are no expected adverse environmental or energy impacts associated with the proposed control alternative. Each turbine shall not exceed 0.014 lb/MMBtu on a higher heating value basis, which is equivalent to 24.0 pounds per hour.

(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:

Combination of Dry Low NO_X (DLN) Combustion and SCONOx Technology
Combination of Dry Low NO_X (DLN) Combustion and Selective Catalytic

Reduction (SCR)
Catalytic Oxidation
Xonon Technology
Dry Low NOx Burners and Good Combustion Practices

Technically Infeasible Control Options – One of the control options were considered to be technically infeasible: Xonon technology. Catalytic combustion (XONON) is an emerging emission control technology that has been introduced commercially by Catalytica, Inc. This technology uses catalytic combustion to reduce NOx emissions from gas turbines to 3-5 ppm. According to Catalytica, Xonon has successfully reduced NOx emission to 3 ppm in laboratory and pilot tests on small turbines. Xonon uses flameless combustion to burn natural gas and requires no down-stream cleanup device to reduce NOx emissions. This technique prevents the formation of thermal NOx during the combustion of fuel and avoids the need for ammonia injection, as with SCR. Xonon may be retrofitted to existing turbines because it replaces the diffusion or lean pre-mix combustion cans.

In the Xonon technology, a fuel and air mixture is oxidized across several small catalyst beds, which combusts the fuel at a temperature lower than that at which thermal NOx is formed. A partial flame is used downstream to complete the combustion process where unavoidable small amounts of NOx are formed. The Xonon catalyst will age with time, as with other catalyst. However, the Xonon catalyst can be easily replaced with a combustor replacement.

Currently Xonon is not available for large industrial gas turbines such as GE Frame 7FA According to a press release from Catalytica, GE and Catalytica are collaborating on the Pastoria Energy Facility project in Bakersfield California to adapt the Xonon to fit the GE Frame 7FA turbines. The project is expected to begin construction in 2001 and enter commercial operations by the summer of 2002. However, presently GE does not offer a Xonon combustor on any large industrial turbines. Xonon is not considered to be a commercially control technology for the LCPP. Furthermore, neither GE nor Catalytica could provide cost data for the Xonon technology and therefore Xonon was not considered a viable control alternative for this project.

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.

The calculated average cost effectiveness of SCONOx technology with DLN combustion is $39,990/ton NOx removed. However, this does not include other operating and maintenance costs expected due to malfunctioning of catalyst regeneration process nor the economic impacts of forced outages to handle those events. The application of SCONOx for the LCPP will be economically infeasible for the combustion turbine generators with duct burners on. Additionally, because the process has not been demonstrated on the frame 7FA turbines, it is also not technically feasible.

Selective Catalytic Reduction (SCR)

The LCPP proposes the use of combination of dry low NOx (DLN) combustion and selective catalytic reduction (SCR), which represents the most stringent commercially available NOx control technology. Therefore the other least effective control will not be analyzed.

The SCR will be added as a post combustion treatment for NOx emissions by injecting ammonia into the turbine /duct burner exhaust stream and upstream from the catalyst unit. The SCR unit houses a catalyst typically made from noble metals, base metal exides such as vanadium and titanium, and zeolite based material. The ammonia injected exhaust stream enters and reacts with catalyst beds to form N2 and H2O.

The Reaction mechanisms involved in the process are very temperature-sensitive and can be used to reduce NOx only over a narrow temperature window. 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.

<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 emission limitations established for similar sized combustion turbines:

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm@15%O_2	Control Description
Proposed Cogentrix Facility	Turbine	3 x 2244	3.0 (3-hr avg.)	DLN + SCR
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., OR	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 that the unit can achieve 2.5 ppm utilizing SCONOX. This source, however, is also located in a nonattainment area, so LAER is applied.

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.

Conclusion – Based on the information presented above, the NOx BACT shall be the use of low NOx burner design in conjunction with SCR control with an emission limit of 3.0 ppmvd corrected to 15% O2. The emission limit is equivalent to 29.7 pounds of NOx per hour for each combustion turbine, when its associated duct burner is in operation and 25.9 lb/hr, when its duct burner is not operating. There are no anticipated adverse environmental impacts associated with this control technology. The combination of dry low NOx combustion and SCR represents the most stringent technically feasible control technology.

During periods of startup and shutdown (less than 70 percent load) the NO_X emission limit for each combustion turbine stack shall not exceed 51.04 lb/hr corrected to 15% O_2 and 17.5 lb/hr corrected to 15% O_2, respectively. The startup or shutdown period shall not exceed a period of 250 minutes. 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.

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

SCONOX
Catalyst Oxidation
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.

SCONOX

Because this technology has not been demonstrated on the frame 7FA turbines the application of SCONOx technology is not feasible for NOX control, and therefore is not considered for CO control.

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, back pressure 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. The installed capital cost associated with catalytic oxidation is $2,089,585 and the annualized cost is $852, 796 per turbine when firing natural gas. The cost-effectiveness is $7,850 per ton CO removed. These cost impacts are considered to be excessive.

The energy impact is the result of pressure loss through the catalyst, which reduces the turbine power output. The estimated annual energy impact is $37,450.

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 Cogentrix facility	Turbine (3) / Duct Burner	2244.1	12.2	Good Combustion
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 Cogentrix facility showed it would cost 7,850 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. The CO emission rate under maximum load conditions will be limited to 12.2 ppmvd at 15% O_2 for each combustion turbine with duct burner firing, which is equivalent to 62.0 lbs/hr, and 9.0 ppm, equivalent to 35 lb/hr, when its associated duct burner is not operating.

A review of EPA's RBLC database indicates that other combustion turbines that utilize natural gas have been issued permits with BACT-based CO emissions in the range of 3 to 60 ppm (based on full load operation). Given the regional air quality conditions and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, the proposed emission limits are believed to be representative of a top level emission control. There are no expected adverse economic, environmental or energy impacts associated with the proposed control alternative.

During periods of startup and shutdown (less than 70 percent load) the CO emission limit for each combustion turbine stack shall not exceed 281.7 lbs/hr @15% O_2 and 130.75 lbs/hr @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:

Flue Gas Desulfurization (FGD)
The use of Low Sulfur Fuels
Scrubber

Discussion – Control techniques available to reduce SO2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. Flue Gas desulfurization is a process that uses limestone, lime, and other industrial minerals to control sulfur dioxide emissions from coal burning power plants and other facilities. Increased interest in FGD has ranked this technology as the most widely used sulfur dioxide control technology. A review of the RBLC indicates that while FGD systems are common on boiler applications, there are no known FGD systems on combustion turbines. Thus, the use of an FGD is rejected as a BACT control alternative.

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_2 BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), that results from the use of natural gas. The maximum estimated SO_2 emissions would be 0.006 lb/MMBtu for the turbines and associated duct burners, which is an equivalent of 13.2 pounds per hour, and equivalent to 11.7 lb/hr for turbines with no duct burner operating.

(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:

Catalytic Oxidation
Good Combustion Practices/Design
SCONOX

Discussion – Catalytic oxidation of VOC is a technically proven control alternative for combustion turbines: however, it has been primarily used to meet specialized requirements such as LAER, typically in areas that are designated as non-attainment for ozone. This technology utilizes a catalyst to promote the oxidation of CO and unburned hydrocarbon to $CO_{2.}$ Catalytic oxidation can achieve a VOC reduction efficiency of 50% with VOC compounds larger than ethane.

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.

The cost effectiveness of catalytic oxidation is $55,660 per ton VOC removed and is considered to be excessive. Because of the adverse economic and energy impacts catalytic oxidation is rejected as a BACT control alternative.

Existing BACT Emission Limitations – 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 Cogentrix Facility	Turbine	1944	0.0019	Combustion Control
	Duct Burner	300	.0037 (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 Duct Burner	1777	0.016	Combustion Control
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 Duct Burner	1988	0.008	Combustion Control
Narragansett Electric, RI	Turbine Duct Burner	1360	5 ppm	Combustion Control
Saranac Energy, NY	Turbine	1123	0.0045	Oxidation Catalyst
	Duct Burner	553	0.011	
Southern Energy, MI	Turbine Duct Burner	1000 MW	0.008	Combustion Control
LS Power, IL	Turbine	2166	0.012	Combustion Control
	Duct Burner		0.019	

Almost all of the recent permits listed in the RLBC database indicate that good combustion practices/design is the preferred method of VOC control on combined cycle combustion turbines with duct burners. There are no expected adverse economic, environmental, or energy impacts associated with good combustion practices/design.

Also, an oxidation catalyst would not be economically feasible because of the lower inlet CO emissions associated with new combustion technology.

Conclusion – Based on the information presented above, BACT shall be good combustion practices/design for control of VOC emissions for the combustion turbines with duct burners on. The VOC emission limit from each turbine shall not exceed 0.0034 lb/MMBtu on a higher heating value basis, which is equivalent to 7.6 lb/hr, and 0.0019 lb/MMBtu, which is equivalent to 3.6 lb/hr for each turbine without the duct burner operating.

(B) Auxiliary Boiler

One natural gas-fired boiler will be installed to provide an alternate source of steam for facility heating and soft starting the combustion turbine systems. The auxiliary boiler has a rated heat input of 35 million BTUs per hour. The auxiliary boiler will fire a maximum of 3,000 hours per year and will vent through a separate stack. The boiler will exclusively use natural gas as a fuel. The purpose of the auxiliary boiler is 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 boiler 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 boiler. 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 boiler.

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 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:

Fabric Filter (Baghouse)
Good combustion Practice/Design

Technically Infeasible Control Options – All control options are basically technically infeasible because the sole fuel for the proposed auxiliary boiler 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 Cogentrix Facility	Boiler	35	0.02	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 RBLC database indicates that there are no BACT precedents for natural gas-fired boilers requiring add-on controls for TSP/PM10 emissions.

Conclusion – Based on the information presented above the PM/PM_{10} BACT for the auxiliary boiler is the use of a low ash fuel and efficient combustion. Opacity is also not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no expected adverse environmental or energy impacts associated with the proposed control alternative. The PM/PM_{10} emissions from the each auxiliary boiler shall not exceed 0.70 pounds per hour (0.02 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 Options 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. The impact on NO_X emissions associated with water/steam injection causes 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 boiler is 366 ^oF. Therefore, a significant amount of preheat 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.

Selective non-catalytic reduction (SNCR) is a post combustion NO_X control technology based on the reaction of ammonia and NO_X. SNCR involves injection ammonia 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 ammonia slip, operation above this range results in oxidation of ammonia, forming additional NO_X. The ammonia 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. Because the boiler is considered to control NOx in this boiler as well as Low NOx burner, it is considered as a less stringent control.

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 Cogentrix Facility	Boiler	35	0.08	lb/MMBtu	Good Design and Operation
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

Conclusion – Based on the information presented above, the NO_X BACT for the auxiliary boiler shall be the use of Low NO_X burner. The emission limit of NO_X will be 0.08 lb/MMBtu on a higher heating value basis, which is equivalent to 2.80 lbs/hr.

(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:

Flue Gas Desulfurization (FGD)
Scrubber
Natural Gas Combustion

Discussion – Control techniques available to reduce SO2 emissions include flue gas desulfurization (FGD) systems and the use of low sulfur fuels. Flue Gas desulfurization is a process that uses limestone, lime, and other industrial minerals to control sulfur dioxide emissions from coal burning power plants and other facilities. Increased interest in FGD has ranked this technology as the most widely used sulfur dioxide control technology.

A review of the RLBC indicates that while FGD systems are common on boiler applications, there are no known FGD systems on combustion turbines. The use of an FGD is rejected as a BACT control alternative.

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_2 BACT shall be the use of very low sulfur natural gas. The SO_2 emission limit from each boiler shall be 0.006 lb/MMBtu, which is equivalent to 0.21 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:

Catalytic Oxidation
Good Design/Operation

Discussion – 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.

The cost of add-on controls on intermittently operated facilities is prohibitive. However, controlling boiler-operating conditions can minimize carbon monoxide emission. This includes proper burner settings, maintenance of burner parts, and sufficient air residence time, and mixing, for complete combustion.

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 Cogentrix Facility	Boiler	35	2.87	lb/hr	Good Combustion Practice/Design
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

The majority of the entries in the RBCL database to control CO emissions from natural gas fire boilers are 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 Cogentrix facility is 2.87 lbs/hr.

Conclusion – Based on the information presented above, the CO BACT shall be boiler design and good operating practices. The auxiliary boiler shall not exceed 0.082 lb/MMBtu, which is equivalent to 2.87 lbs/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 controls.

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

Catalytic Oxidation and Proper Boiler Design
Good Design/Operation

Discussion – Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbon to CO. 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 °F. 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 Cogentrix Facility	Boiler	35	0.39	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

The majority 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 0.39 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 Cogentrix auxiliary boiler.

Conclusion – Based on the information presented above, the VOC BACT for each auxiliary boiler at the proposed Cogentrix facility shall be good design and operation, and a fuel usage limitation equivalent to 3,000 hours per year. Each boiler shall be limited to 0.011 lb/MMBtu, which is an equivalent of 0.39 lb/hr.

(C) Three Cooling Towers

Cooling towers fall into two main sub-divisions: natural draft and mechanical draft. The cooling towers for this particular source will be multi-celled, mechanical draft, counterflow type with an associated liquid drift. This drift is a source of particulate emission, caused by dissolved and suspended solids inherently contained within the liquid droplets. The water droplets then will evaporate allowing the particulates to agglomerate. The particle sizes are mostly in the 20 to 30 micron range.

(1) PM BACT Review

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. 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.

Cooling towers act as giant air washers. Finely misted water is sprayed into a column of moving air. In a cooling tower, this mist is intended to increase the surface area of the water so heat will be more effectively transferred from the water to the air. In an air

washer, this mist is intended to trap particulate matter out of the air and "wash" it into the sump for disposal.

Control Options Evaluated

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Good Design/Operation
Drift Eliminators

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.

There are no technically feasible alternatives that can be installed on the cooling towers, which specifically reduce particulate emissions; however, cooling towers are typically designed with drift elimination features. The drift eliminators are specially designed baffles that collect and remove condensed water droplets in the air stream. These drift eliminators, according to review of the RBLC can reduce drift to 0.0015 percent to 0.004 percent of cooling water flow, which reduces particulate emissions

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 Cogentrix Facility	Cooling Tower	Drift Eliminator	0.002	3.43	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

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 0.002 percent. The total particulate emissions from the cooling towers shall not exceed 3.43 pounds per hour.