INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Frank O'Bannon
Governor

Lori F. Kaplan
Commissioner

100 North Senate Avenue
P.O. Box 6015
Indianapolis, Indiana 46206-6015
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NEW SOURCE CONSTRUCTION PERMIT
Prevention of Significant Deterioration (PSD) Permit
Office of Air Quality

Acadia Bay Energy Co.LLC
Corner of Walnut and Edison
New Carlisle, IN

(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.

Operation Permit No.: CP 141-14198-00543	
Issued by: Original Signed by Paul Dubenetzky Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date: December 7, 2001

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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 630 megawatt electric generating station.

Authorized Individual:	Chris Herter
Source Address:	Corner of Walnut and Edison, New Carlisle, Indiana
Mailing Address:	25 Merganser Way, Freeport, ME 04032
Phone Number:	(207) 865-4554
SIC Code:	4911
County Location:	St.Joseph
County Status:	Attainment for all criteria pollutants
Source Status:	Major under PSD

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:

Combined Cycle

(a) Two (2) natural gas-fired combined cycle combustion turbine generators designated as units CTG-01 and CTG-02, with a maximum heat input capacity of 2,071 MMBtu/hr (per unit on a higher heating value), and exhausting to stacks designated as S1 and S2, respectively.

(b) Two (2) heat recovery steam generators, designated as units HRSG1 and HRSG2.

(c) Two (2) selective catalytic reduction systems.

(d) One (1) cooling tower, consisting of 9 cells designated as Cool1 and exhausts to stack designated as S5 (A)-(I).

(e) One (1) auxiliary boiler, designated as unit Aux06 with maximum heat input rating of 21 MMBtu/hr, and exhausts to stack designated as S6.

(f) One (1) condensing steam turbine generator with an electric generating capacity of 178 MW at baseload design conditions.

Simple Cycle

(g) Two (2) natural gas-fired simple cycle combustion turbine generators designated as units CTG-03 and CTG-04 with a maximum heat input capacity of 469 MMBtu/hour (per unit on a higher heating value), and exhausting to stacks designated as S3 and S4, respectively.

(h) One (1) emergency diesel generator utilizing low sulfur diesel fuel, with a maximum capacity of 300 KW and exhausts to stack designated as S7.

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

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

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

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

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

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

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

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

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

SECTION B GENERAL CONSTRUCTION CONDITIONS

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

B.1 Permit No Defense [IC 13]

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

B.2 Definitions

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

B.3 Effective Date of the Permit [IC13-15-5-3]

Pursuant to 40 CFR Parts 124.15, 124.19 and 124.20, the effective date of this permit will be thirty (30) days after the service of notice of the decision. Three (3) days shall be added to the thirty (30) day period if service of notice is by mail.

B.4 Permit Expiration Date [326 IAC 2-2-8(a)(1)] [40 CFR 52.21(r)(2)]

Pursuant to 40 CFR 52.21(r)(2) and 326 IAC 2-2-8(a)(1) (PSD Requirements: Source Obligation) 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 continuous 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

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

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

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

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

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

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

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

(c) PMP's shall be submitted to IDEM, OAQ 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 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 Emergency Reduction Plans [326 IAC 1-5-2] [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 Quality
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.12 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 shall be implemented when operation begins.

C.13 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.14 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.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 Emission Reporting [326 IAC 2-6]

Pursuant to 326 IAC 2-6, the owner/operator of this Source must annually submit an emission statement of the Source. The annual statement must be received by April 15 of each year and must contain the minimum requirements as specified in 326 IAC 2-6-4.

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 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 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 EMISSIONS UNIT OPERATION CONDITIONS – Combined Cycle Combustion Turbines

(a) Two (2) natural gas-fired combined cycle combustion turbine generators designated as units CTG-01 and CTG-02, with a maximum heat input capacity of 2,071 MMBtu/hr (per unit on a higher heating value), and exhausting to stacks designated as S1 and S2, respectively.

(b) Two (2) heat recovery steam generators, designated as units HRSG1 and HRSG2.

(c) Two (2) selective catalytic reduction systems.

(d) One (1) cooling tower, consisting of 9 cells designated as Cool1 and exhausts to stack designated as S5 (A)-(I).

(e) One (1) condensing steam turbine generator with an electric generating capacity of 178 MW at baseload design conditions.

(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 Particulate Matter (PM/PM_{10}) Emission Limitations for Combined Cycle Combustion Turbines [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the PM (filterable) emissions or PM_{10} (filterable and condensible), emissions from each combined cycle combustion turbine shall not exceed 0.012 pounds per MMBtu (lower heating value basis) which is equivalent to 23 pounds per hour.

(b) Pursuant to 326 IAC 6-1-2(a), the PM emissions from each combustion turbine stack shall not exceed 0.03 grains per dry standard cubic feet.

D.1.2 Opacity Limitations [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements) the opacity from each 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.1.3 Nitrogen Oxides (NO_X) Emission Limitations for Combined Cycle Combustion Turbines [326 IAC 2-2]

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

(1) During normal combined cycle operation (seventy (70) percent load or more), the NO_X emissions from each combined cycle combustion turbine stack shall not exceed 2.5 ppmvd corrected to fifteen (15) percent oxygen, based on a three (3) hour block average period, which is equivalent to 18.7 pounds per hour.

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

(3) 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.

(4) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from the combined cycle combustion turbine, excluding startup and shutdown emissions, shall not exceed 142.91 tons per year.

D.1.4 Carbon Monoxide (CO) Emission Limitations for Combined Cycle Combustion Turbines [326 IAC 2-2]

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

(1) During normal combined cycle operation (seventy (70) percent load or more), the CO emissions from each combined cycle combustion turbine shall not exceed 6 ppmvd corrected to 15% O_2 on a 24 hour block average period, which is equivalent to 27.3 pounds per hour.

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

(3) Use natural gas as the only fuel

(4) From the date of start of commercial operation of combined cycle combustion turbines, the facility will have 6 months to evaluate the ability to achieve a CO limit of 6 ppmvd at 15% O_2 based on a 24-hour block average, without an oxidation catalyst. If this limit cannot be achieved after the 6 months evaluation period, the facility will have 18 months from the date of the start of commercial operation of combined cycle combustion turbines to install an oxidation catalyst and demonstrate compliance with the specified limit.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from the combined cycle combustion turbine, excluding startup and shutdown emissions, shall not exceed 112 tons per year.

D.1.5 Sulfur Dioxide (SO_2) Emission Limitations for Combined Cycle Combustion Turbines [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), each combined cycle combustion turbine shall comply with the following:

(1) the SO_2 emissions from each combined cycle combustion turbine shall not exceed 0.0034 pounds per MMBtu (lower heating value basis), which is equivalent to 6.0 pounds per hour.

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

(3) Perform good combustion practice.

D.1.6 Volatile Organic Compound (VOC) Emission Limitations for Combined Cycle Combustion Turbines [326 IAC 2-2] [326 IAC 8-1-6]

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 combined cycle combustion turbine shall not exceed 0.0034 pounds per MMBtu (lower heating value basis), which is equivalent to 6.0 pounds VOC per hour.

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

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

D.1.7 40 CFR 60, Subpart GG (Stationary Gas Turbines)

Two (2) natural gas combined cycle combustion turbines identified as CTG-01 and CTG-02 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.1.8 Formaldehyde Limitations [326 IAC 2-4.1-1]

The formaldehyde emission from the combined cycle combustion turbines shall not exceed 0.000202 lb/MMBtu. This shall limit the combined formaldehyde emissions from the entire source to less than ten (10) tons per year and make requirements of 326 IAC 2-4.1 not applicable. Any increase in single Hazardous Air Pollutant (HAP) emissions greater than the threshold specified above and combined HAPs greater than twenty five (25) tons per year, from the entire Source must be approved by the Office of Air Quality (OAQ) before such change may occur.

D.1.9 Ammonia Limitations [326 IAC 2-1.1-5]

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the ammonia emissions from each combined cycle combustion turbine stack:

(a) shall not exceed ten (10) ppmvd corrected to 15% O_2 on 3 hour block average basis, and

(b) shall not exceed 226 tons per calendar year.

D.1.10 Startup and Shutdown Limitations for Combined Cycle Combustion Turbines [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), following shall apply to the combined cycle combustion turbines:

(a) Two (2) combined cycle combustion turbines are organized in a power block.

(b) Startup is defined as the period of time from initiation of combustion firing until both units in the power block reach steady state operation (i.e. loads greater than 70%).

(c) Shutdown is defined as that period of time from the initial lowering of the turbine output, with the intent to shutdown, until the time at which the combustion is completely stopped.

(d) Power block (consisting of two turbines) shall comply with the following:

i. The maximum number of events (where one event is one startup and one shutdown) shall not exceed 210 per 12 consecutive months period rolled on monthly basis as determined at the end of each calendar month. The duration of an event shall not exceed 4.16 hours. The total number of hours under startup/shutdown mode shall not exceed 585 hours per 12 consecutive months period rolled on monthly basis.

ii. The NO_X emissions from power block shall not exceed 1078 pounds per event.

iii. The CO emissions from power block shall not exceed 3935 pounds per event.

D.1.11 Particulate Matter Emissions (PM/PM_{10}) for Cooling Tower [326 IAC 2-2]

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

(1) PM emissions shall not exceed 0.49 pounds per hour, and

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

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

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

Compliance Determination Requirements

D.1.13 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 combined cycle combustion turbine exhaust stack in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within one hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde stack test for each combined cycle combustion turbine stack utilizing a method approved by the Commissioner when operating at 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to verify the formaldehyde emission factor specified in condition D.1.8.

(c) 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 combined cycle combustion turbine stack 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.1.7.

(d) Within one-hundred and eighty (180) days after initial startup, the Permittee shall perform VOC, and ammonia stack tests for each combined cycle combustion turbine stack 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.1.6, and D.1.9.

(e) 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.1.14 Oxides of Nitrogen NOx (SCR operation) [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD requirements), the Permittee shall determine optimum temperature of the catalyst bed during the stack test requirement in condition D.1.13 (a) (d) that demonstrates compliance with limits in condition D.1.3, as approved by IDEM.

(b) From the date of the valid stack test, during a startup, the Permittee shall start ammonia injection in the SCR units to control NOx emissions from the gas turbines, as soon as the catalyst bed reaches the temperature determined in part (a) above or turbine load reaches 70%, whichever occurs earlier.

D.1.15 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 3031-81, D 4084-82, D 3246-81, or other applicable methods approved by IDEM. 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.1.16 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 continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO, for stacks designated as 1 and 2 in accordance with 326 IAC 3-5-2 through 326 IAC 3-5-7.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in parts per million (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NO_X and CO concentration, 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) corrected to 15% O_2 over a three (3) hour block. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a twenty four (24) hour averaging period. The source shall maintain records of the parts per million and the pounds per hour, using Method 19.

(2) The Permittee shall determine compliance with Condition D.1.10 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.1.17 Record Keeping Requirements

(a) To document compliance with Conditions D.1.1, D.1.5, D.1.6 and D.1.8, 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.1.10, the Permittee shall maintain records of the following:

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

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

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

(c) To document compliance with Conditions D.1.3 and D.1.4, 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.1.15, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

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

D.1.18 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.1.3 and D.1.4 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

(d) A quarterly summary of the total number of startup and shutdown hours of operation, and emissions for the corresponding startup and shutdown to document compliance with Condition D.1.10, 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 EMISSIONS UNIT OPERATION CONDITIONS – Simple Cycle Combustion Turbines

Two (2) natural gas-fired simple cycle combustion turbine generators designated as units CTG-03 and CTG-04 with a maximum heat input capacity of 469 MMBtu/hour (per unit on a higher heating value), and exhausting to stacks designated as S3 and S4, respectively. (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.2.1 Simple Cycle Combustion Turbines limitations on Hours of Operation [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), the total collective hours of operation for the two simple cycle combustion turbine shall not exceed 7000 per 12 consecutive months period rolled on monthly basis.

(b) Pursuant to 326 IAC 6-1-2(a), the PM emissions from each combustion turbine stack shall not exceed 0.03 grains per dry standard cubic feet.

D.2.2 Particulate Matter (PM/PM_{10}) Emission Limitations for Simple Cycle Combustion Turbines [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), the PM (filterable) emissions or PM_{10} (filterable and condensable), emissions from each simple cycle combustion turbine shall not exceed 0.00675 pounds per MMBtu (lower heating value basis) which is equivalent to 2.7 pounds per hour.

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

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

D.2.4 Nitrogen Oxides (NO_X) Emission Limitations for Simple Cycle Combustion Turbines [326 IAC 2-2]

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

(1) During normal simple cycle operation (seventy (70) percent load or more), the NO_X emissions from each simple cycle combustion turbine stack shall not exceed 25 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 42 pounds per hour.

(2) Each combustion turbine shall be equipped with water injection for NOx control and operated using good combustion practices to control NO_X emissions.

(3) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from the simple cycle combustion turbine, excluding startup and shutdown emissions, shall not exceed 140 tons per year.

D.2.5 Carbon Monoxide (CO) Emission Limitations for Simple Cycle Combustion Turbines [326 IAC 2-2]

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

(1) During normal simple cycle operation (seventy (70) percent load or more), the CO emissions from each simple cycle combustion turbine shall not exceed limits in following table corrected to 15% O_2 on a 24 operating hour averaging period.

Ambient temperature range	CO emissions concentration in ppmvd at 15% O_2
Greater than 70°F	25
From 30°F to 70°F	50
From 0°F to 30°F	75
Less than 0°F	100

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

(3) Use natural gas as the only fuel

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from the simple cycle combustion turbines, excluding startup and shutdown emissions, shall not exceed 116 tons per year.

D.2.6 Sulfur Dioxide (SO_2) Emission Limitations for Simple Cycle Combustion Turbines [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), each simple cycle combustion turbine shall comply with the following:

(1) the SO_2 emissions from each simple cycle combustion turbine shall not exceed 0.0035 pounds per MMBtu (lower heating value basis).

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

(3) Perform good combustion practice.

D.2.7 Volatile Organic Compound (VOC) Emission Limitations for Simple Cycle Combustion Turbines [326 IAC 2-2] [326 IAC 8-1-6]

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 simple cycle combustion turbine shall not exceed 0.02 pounds per MMBtu (lower heating value basis), which is equivalent to 8.0 pounds VOC per hour.

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

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

D.2.8 40 CFR 60, Subpart GG (Stationary Gas Turbines)

Two (2) natural gas simple cycle combustion turbines identified as CTG-03 and CTG-04 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.2.9 Formaldehyde Limitations [326 IAC 2-4.1-1]

The formaldehyde emission from the simple cycle combustion turbines shall not exceed 0.00113 lb/MMBtu. This shall limit the combined formaldehyde emissions from the entire source to less than ten (10) tons per year and make requirements of 326 IAC 2-4.1 not applicable. Any increase in single Hazardous Air Pollutant (HAP) emissions greater than the threshold specified above and combined HAPs greater than twenty five (25) tons per year, from the entire Source must be approved by the Office of Air Quality (OAQ) before such change may occur.

D.2.10 Startup and Shutdown Limitations for Simple Cycle Combustion Turbines [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD Requirements), the following shall apply to the simple cycle combustion turbines:

(a) Startup is defined as the period of time from initiation of combustion firing until simple cycle combustion turbine reaches steady state operation (i.e. loads greater than 70%).

(b) Shutdown is defined as that period of time from the initial lowering of the turbine output, with the intent to shutdown, until the time at which the combustion is completely stopped.

(c) Simple Cycle Combustion Turbines shall comply with the following:

i. The maximum number of events (where one event is one startup and one shutdown) for each simple cycle combustion turbine shall not exceed 500 per 12 consecutive months period rolled on monthly basis as determined at the end of each calendar month. The duration of an event shall not exceed 0.35 hours. The total number of hours under startup/shutdown mode shall not exceed 175 hours per 12 consecutive months period rolled on monthly basis.

ii. The NO_X emissions for each Simple Cycle Combustion Turbine shall not exceed 36 pounds per event.

iii. The CO emissions from each Simple Cycle Combustion Turbines shall not exceed 29.2 pounds per event.

D.2.11 Preventive Maintenance Plan [326 IAC 1-6-3]

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

Compliance Determination Requirements

D.2.12 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 simple cycle combustion turbine exhaust stack in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within one hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde stack test for each simple cycle combustion turbine stack utilizing a method approved by the Commissioner when operating at 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to verify the formaldehyde emission factor specified in condition D.2.9.

(c) 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 simple cycle combustion turbine stack utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with Condition D.2.8.

(d) Within one-hundred and eighty (180) days after initial startup, the Permittee shall perform VOC stack tests for each simple cycle combustion turbine stack utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335, 40 CFR 60.48(a), and Section C – Performance Testing, in order to document compliance with D.2.7.

(e) 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.2.13 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 3031-81, D 4084-82, D 3246-81, or other applicable methods approved by IDEM. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator; and

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

The analyses required above may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor or any other qualified agency.

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

D.2.14 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 continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO, for stacks designated as 3 and 4 in accordance with 326 IAC 3-5-2 through 326 IAC 3-5-7.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions in parts per million (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NO_X and CO concentration, 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) corrected to 15% O_2 over a twenty four (24) hour block. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppm) corrected to 15% O_2 over a twenty four (24) hour averaging period. The source shall maintain records of the parts per million and the pounds per hour, using Method 19.

(2) The Permittee shall determine compliance with Condition D.2.10 utilizing data from the NO_X, CO, and O_2 CEMS, the fuel flow meter, and Method 19 calculations.

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

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

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

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

D.2.15 Record Keeping Requirements

(a) To document compliance with Conditions D.2.1, D.2.6, D.2.7 and D.2.9, the Permittee shall maintain records of the following:

(1) Hours of operation of each simple cycle combustion turbine during each month.

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

(3) Percent sulfur of the natural gas.

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

(b) To document compliance with Condition D.2.10, the Permittee shall maintain records of the following:

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

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

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

(c) To document compliance with Conditions D.2.4 and D.2.5, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and parts per million (ppmvd) corrected to 15% oxygen.

(d) To document compliance with Condition D.2.13, 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) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit.

D.2.16 Reporting Requirements

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

(e) 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.

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

(g) A quarterly summary of the CEMs data to document compliance with D.2.4 and D.2.5 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

A quarterly summary of the total number of startup and shutdown hours of operation, and emissions for the corresponding startup and shutdown to document compliance with Condition D.2.10, shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

SECTION D.3 FACILITY CONDITIONS – Auxiliary Boiler

One (1) auxiliary boiler, designated as unit Aux06 with maximum heat input rating of 21 MMBtu/hr, and exhausts to stack designated as S6. (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 Particulate Matter Emissions (PM/PM_{10}) for Auxiliary Boiler [326 IAC 2-2]

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

(i) The PM (filterable only) or PM_{10} (filterable and condensable) emissions from the auxiliary boiler shall not exceed 0.0075 lb/MMBtu on a higher heating value basis, which is equivalent to 0.158 pounds per hour.

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

(iii) Perform good combustion practices

(b) Pursuant to 326 IAC 6-1-2(b)(1) the PM emissions from auxiliary boiler shall be less than 0.01 grains per dry standard cubic feet (dscf).

D.3.2 Opacity Limitations [326 IAC 2-2]

Pursuant to 326 IAC 2-2, the Permittee shall not cause the average opacity of the auxiliary boiler stack to exceed twenty percent (20%) in any one (1) six (6) minute period, except for 1 six minute period per hour of not more than 27% opacity. The opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

D.3.3 Nitrogen Oxide (NO_X) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

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

(a) The NOx emissions from the auxiliary boiler shall not exceed 0.049 lb/MMBtu on a higher heating value basis, which is equivalent to 1.029 pounds per hour.

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

(c) Operate the auxiliary boiler using low-NOx burners.

D.3.4 Carbon Monoxide (CO) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

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

(a) The CO emissions from the auxiliary boiler shall not exceed 0.082 lb/MMBtu on a higher heating value basis, which is equivalent to 1.72 pounds per hour.

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

(c) Operate utilizing good combustion practices.

D.3.5 Sulfur Dioxide (SO_2) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

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

(a) Emissions from the auxiliary boiler shall not exceed 0.0006 lb/MMBtu on a higher heating value basis, which is equivalent to 0.012 pounds per hour.

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

(c) Operate utilizing good combustion practices.

D.3.6 Volatile Organic Compound (VOC) Emission Limitations for Auxiliary Boiler [326 IAC 2-2]

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) The VOC emissions from the auxiliary boiler shall not exceed 0.0054 lb/MMBtu on a higher heating value basis, which is equivalent to 0.12 pounds per hour.

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

(c) Operate using good combustion practices.

D.3.7 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 the proposed auxiliary boiler is 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.

D.3.8 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 the auxiliary boiler.

Compliance Determination Requirements

D.3.9 Performance Testing

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

(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.3.10 Record Keeping Requirements

(a) The Permittee shall maintain records of the amount of natural gas combusted for auxiliary boiler during each month.

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

D.3.11 Reporting Requirements

The Permittee shall submit the following information on a quarterly basis: a summary of the information as per requirements of D.3.7 to the addresses listed in Section C - General Reporting Requirements, using the reporting forms located at the end of this permit, or their equivalent, within thirty (30) days after the end of the quarter being reported.

SECTION D.4 FACILITY CONDITIONS – Backup Equipment

One (1) emergency diesel generator utilizing low sulfur diesel fuel, with a maximum capacity of 300 KW and exhausts to stack designated as S7. (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.4.1 BACT Limitation [326 IAC 2-2]

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

(a) The total fuel input for generator shall not exceed 14,210 gallons per twelve (12) consecutive month period, rolled on a monthly basis. This is equivalent to 500 hours of operation in a year.

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

(c) Perform good combustion practice.

Compliance Determination Requirements

D.4.2 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.4.3 Record Keeping Requirements

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

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

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

D.4.4 Reporting Requirements

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

MALFUNCTION REPORT

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

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

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

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

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

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

COMPANY:____PHONE NO. ( )______________________
LOCATION: (CITY AND COUNTY)____
PERMIT NO. ________________ AFS PLANT ID: ________________ AFS POINT ID: ________________ INSP:__________
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON:____
____

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

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION: ________________________________

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

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

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: ____________________________
____

MEASURES TAKEN TO MINIMIZE EMISSIONS:____
____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

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

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

MALFUNCTION RECORDED BY:____________________DATE:______________TIME:______________

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

326 IAC 1-6-1 Applicability of rule

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

326 IAC 1-2-39 "Malfunction" definition

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

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

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

____
____

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Acadia Bay Energy Co. LLC
Location: Corner of Walnut and Edison, New Carlisle, Indiana
Permit No.: CP-141-14198-00543
Source: Emergency generator
Limit: 14,210 gallons per twelve (12) consecutive month period

Year: ____________

Month	Column 1 Diesel Fuel Oil Usage (gallons/month)	Column 2 Diesel Fuel Oil Usage for previous 11 months (gallons)	Column 1 + Column 2 Diesel Fuel Oil Usage for twelve month period (gallons)

☐ No deviation occurred in this quarter.

☐ 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: Acadia Bay Energy Co. LLC
Location: Corner of Walnut and Edison, New Carlisle, Indiana
Permit No.: CP-141-14198-00543
Source: one (1) power block consisting of two (2) natural gas fired combined cycle combustion turbines
Limit: 210 events (an event is one startup and one shutdown) for the power block, and 584 hours for events in a 12 consecutive month period

Year: ____________

Month	Column 1 Events (This month)		Column 2 Number of events previous 11 months		Column 1 + Column 2 Number of events for twelve month period	
	Number	Hours	Number	Hours	Number	Hours

☐ No deviation occurred in this month

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

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

Indiana Department of Environmental Management
Office of Air Quality
Compliance Data Section

Quarterly Report

Company Name: Acadia Bay Energy Co. LLC
Location: Corner of Walnut and Edison, New Carlisle, Indiana
Permit No.: CP-141-14198-00543
Source: two (2) natural gas fired simple cycle combustion turbines
Limit: 500 events (an event is one startup and one shutdown) per turbine, and 175 hours for events in a 12 consecutive month period

Year: ____________

Month	Column 1 Events (This month)		Column 2 Number of events previous 11 months		Column 1 + Column 2 Number of events for twelve month period	
	Number	Hours	Number	Hours	Number	Hours

☐ No deviation occurred in this month

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

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

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

SEMI-ANNUAL NATURAL GAS FIRED BOILER CERTIFICATION

Company Name: Acadia Bay Energy Co. LLC
Location: Corner of Walnut and Edison, New Carlisle, Indiana
Permit No.: CP-141-14198-00543

☐ Natural Gas Only ☐ Alternate Fuel burned From:_____________ To:_____________

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
Signature:
Printed Name:
Title/Position:
Phone:
Date:

A certification by the responsible official as defined by 326 IAC 2-7-1(34) is required for this report.

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document for New Construction and Prevention of Significant Deterioration Permit

Source Background and Description

Source Name: **Acadia Bay Energy Co., LLC**
Source Location: **Walnut and Edison, New Carlisle, Indiana**
County: **St. Joseph**
Construction Permit: **141-14198-00543**
SIC Code: **4911**
Permit Reviewer: **Gurinder Saini**

On October 06, 2001, the Office of Air Quality (OAQ) had a notice published in the South Bend Tribune, South Bend, Indiana, stating that Acadia Bay Energy Co. LLC, had applied for approval to construct and operate a 630 megawatt (MW) electric generating station. The public notice also stated that OAQ proposed to issue the PSD permit for this operation and provided information on how the public could review the proposed approval 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.

Written Comments

Written comments were received from Mr. Stephen Loeschner on October 31, 2001 regarding this permit. The OAQ responses to these comments are as follows. In the responses, additions to the permit are bolded for emphasis; the language with a line through it has been deleted.

Comment 1:

HHV vs. LHV

Most permits dealing with combustion of fuels that produce some water, such as natural gas, are written around the higher heating value ("HHV") of the fuel. This permit seems centered on LHV. This matter is sufficiently confusing that basically *everywhere* within the permit, DEM must make amendment to apply the appropriate prefix.

Response 1:

The OAQ, IDEM agrees that in accordance with U.S. EPA guidance, all turbine heat rate input should be on higher heating value (HHV) basis. Therefore, the OAQ has changed the conditions A.2 (a) and (g) and conditions D.1 (a) and D.2 in the permit as follows:

(a) Two (2) natural gas-fired combined cycle combustion turbine generators designated as units CTG-01 and CTG-02, with a maximum heat input capacity of ~~1,867~~ **2071**MMBtu/hr (per unit on a ~~lower~~ **higher** heating value), and exhausting to stacks designated as S1 and S2, respectively.

(g) Two (2) natural gas-fired simple cycle combustion turbine generators designated as units CTG-03 and CTG-04 with a maximum heat input capacity of ~~423~~ **469** MMBtu/hour (per unit on a ~~lower~~ **higher** heating value), and exhausting to stacks designated as S3 and S4, respectively.

As a result of this change, there are no changes to the potential to emit calculations and rule applicability because that determination was based on HHV at average ambient temperature in the draft permit document for Acadia Bay permit.

Comment 2:

Upon request, Mr. Gurinder Saini (DEM) sent a photocopy of a Siemens / Westinghouse ("S/W") document (attached hereto and incorporated herein) that applies to the large CT's. I'm confident that he sent me the best he had, however it is a small- print tabular page that was at least once transmitted by facsimile. No doubt the U.S. Environmental Protection Agency ("EPA") Appeals Board ("USEAB") judges would require tracking the source and getting a copy that was more legible. Please call the source and have them send one the traditional postal route (making sure that all footnotes are clear) and incorporate it in the Addendum to the Technical Support Document ("ATSD, TSD") for Acadia Bay permit. S/W assumes a pound mass of fuel has 20,665 LHV BTU and 22,931 HHV BTU. I'll apply those factors throughout my comment. Chapter 1 Section 4 of EPA Emission Factors AP-42 (July 1998) and Chapter 3 Section 1 (April 2000) share some attributes. Both mention a stock assumption of 1,020 HHV BTU for a standard cubic foot ("scf") of natural gas. Both seem devoid of mentioning LHV at all; thus an assumption that they are all HHV factors. The EPA 21 August 2001 Sims Roy CT Hazardous Air Pollutant ("HAP") memo ("Roy") does not mention LHV, HHV, 1,020, scf, etc. Based on the AP-42 assumption, a further assumption is that Roy presents HHV factors.

<u>Hexane — A perpetual HAP myth</u>

Roy mentions that roughly two-thirds of the total HAP emission mass from natural gas fueled CT's is formaldehyde ("H2CO") (third para. under Oxidation Catalyst Systems heading). EPA AP-42 para. 3.1.3.5 (April 2000) mentions that roughly two-thirds of the total HAP emission mass from natural gas fueled CT's is H2CO. DEM seems to have no shame in misleading the People, as it wrote in page 19 of the 12432 ATSD 5 October 2001 in response to comment:

"[F]ormaldehyde is not the largest HAP."

It is repugnant that 12 men walked on the moon decades ago and yet the People cannot get a simple accurate answer in re combustion products today. One chemical reaction attribute should be evident by intuition. It is flat out not possible for the components of the air and the "pipeline quality" natural gas fuel, when combusted in a CT, *or in a boiler burner*, to reassemble (or to be present and pass through un-reacted) such that more mixed isomer (or perhaps the n-hexane isomer only?) 6-carbon hexane (containing no oxygen) of molecular weight 86 is emitted than 1-carbon H2CO of molecular weight 30.

Yet DEM, in the HAP table of the *fifth* "page 1 of 1" of Appendix A to the Acadia Bay permit TSD indicates a mass ratio of 0.252 / 0.0705— a domination by hexane by a mass factor of more than 3. There, DEM alleges the large CT hexane emission factor for natural gas fuel combustion came from EPA AP-42 Table 3.1-3 when, in fact, hexane is not in the EPA (April 2000) table.

In the Addendum to the TSD for this permit, please purge all references indicating that hexane is anywhere near H2CO as natural gas combustion effluent, and completely rework the Acadia Bay Permit package to be diligent in re H2CO. I am pleased that DEM SIGECO Posey County PSD Permit drafts 029- 12029- 00010 and 029- 14021- 00010 seem to not mention hexane at all. But I am considerably aggrieved that it has reappeared in Acadia Bay permit following my hexane comments in General Motors Allen County PSD Permit 003- 12830- 00036 2 January 2001 and H2CO comments in re Cogentrix Lawrence County PSD Permit 093- 12432- 00021, 5 June 2001.

Response 2:

There is limited reliable information available on the emissions of Hazardous Air Pollutants (HAPs) from the combustion turbines. The OAQ, IDEM relies on various sources of information (including information provided by the applicant in the form of vendor specifications) to estimate HAPs emissions to determine applicability of various rules to the projects. In the past the emission factors documented in AP-42 were being used to estimate HAPs emissions from the combustion turbine. The AP-42 Chapter 3, table 3.1-3 April/00 version documents the formaldehyde emissions as the largest HAP component from the exhaust of Natural Gas fired turbines. The formaldehyde emissions are at 0.00071 pounds per MMBtu of heat input. The hexane is not listed in this table. The emission rate for formaldehyde is nearly five times greater than the next HAP toluene at 0.00013 pounds per MMBtu. The significant HAP emissions from the gas turbine are in the form of formaldehyde.

As part application for this permit, the applicant had presented in addition to AP 42 emission factors, the California Air Toxics (CAT) emission factors for HAPs from Gas Turbines. The CAT emission factors include formaldehyde at 0.000917 pounds per MMBtu and Hexane at 0.000259 pounds per MMBtu. The hexane emissions included in this review were based on information contained in CAT emission factors. In addition the applicant had supplied vendor specification for formaldehyde emissions at 0.0000705 pounds per MMBtu. The permit required the applicant to stack test for Formaldehyde emissions at different load conditions to show compliance with this alternative emission factor that is included as a limit in the permit.

The OAQ, IDEM has decided to revise the HAPs emissions calculations. The basis for this revision are as following:

1. The emission estimate for HAPs are not based on AP-42 emission factors only. This change has been made after reviewing permits issued by other state agencies in the Region. Therefore, references to hexane as a pollutant in HAPs field has been removed.

2. On August 21, 2001, Sims Roy of Emissions Standards Division, Combustion Group for US EPA published a memorandum regarding HAPs emissions from diffusion flame combustor and lean premix combustor type turbines. The Westinghouse 501 F's are lean premix combustor type turbines. Therefore, according to this memo, the emission factor for formaldehyde with 95^{th} upper percentile confidence is 0.000202 pounds per MMBtu. The applicant has agreed to comply with this emission factor as an emission limit for formaldehyde from the large Westinghouse 501 F combustion turbines. The applicant will perform stack test to show compliance with this emission limit.

3. For the GE LM 6000 46 MW combustion turbines in simple cycle mode, the applicant has presented stack test information from similar other facility, which documents the formaldehyde emissions from these turbines at 0.44 pounds per hour per unit. Using the average heat input rate of 400 MMBtu per hour at 60^oF the emission limit for formaldehyde from the small turbines is 0.0011 lb/MMBtu.

Based on these changes the revised emission calculations are attached to this TSD addendum as appendix A.

Comment 3:

<u>H2CO — Verifiability of minor source status</u>
It appears that ABE is striving to achieve minor source status for H2CO by accepting permit terms which limit the potential to emit to less than the 42 USC 7412(a)(1) 10 tons per year ("tpy") major source threshold.

The 0.0705 pound H2CO per billion (LHV presumed) BTU emission rate limit of Acadia Bay permit D.1.8 and Acadia Bay permit D.1.13(b) tests for the large CT's coupled with the D.2.1 7,000 combined CT-hours operation limit for the small CT's would tend to reasonably meet the synthetic minor status. 0.0705 pounds of H2CO for a billion LHV BTU fuel gas burned: such a quantity of gas would have an approximate mass of 48 thousand pounds, and the mass of carbon in it would be about 36 thousand pounds. The mass of carbon in 0.0705 pounds of H2CO would be about 0.0282 pounds— thus giving the DEM / ABE assertion that for every molecule of H2CO emitted, more than a million carbon atoms, from the fuel, are emitted in some other form. Such clean combustion may be possible (noting Roy's 8-test 0.0649 x 22,931 / 20,665 = 0.07202 pound H2CO per billion LHV BTU emission rate average), however, the 0.0705 pound H2CO per billion

LHV BTU emission rate is rather severe. There is a very real possibility of ABE not meeting that rate and their coming begging to have it relaxed.

Reference is made to the non-guarantee non-contractually binding footnotes in the S/W document. Reference is also made to the S/W document "Case 2" column where 0.13 pounds H2CO / hour is expected from 1.510 billion LHV BTU / hour operation giving a 0.086 pound H2CO per billion LHV BTU emission rate. Recognizing that that computation hangs on a nearly one significant digit number, computing it with a scenario 0.1150 pounds H2CO / hour expected from 1.510 billion LHV BTU / hour operation gives a 0.076 pound H2CO per billion LHV BTU emission rate. And, of course, 0.076 is larger than the 0.0705 draft permit limit by a rather noticeable percentage.

ABE and S/W are to be commended if the 0.0705 pound H2CO per billion LHV BTU emission rate limit and tests are kept and achieved with the large CT's. The Acadia Bay permit D.2.9 1.13 pound H2CO per billion LHV BTU emission rate limit and D.2.12(b) tests are absurd in light of the AP-42 Table 3.1-3 (April 2000) 0.71 x 22,931 / 20,665 = 0.788 pound H2CO per billion LHV BTU emission factor. That was somewhat restated and larger in Roy's Table 1:
0.776 x 22,931 / 20,665 = 0.8611 (average, not high nineties percentile) pound H2CO per billion LHV BTU emission factor.

Response 3:

The formaldehyde emissions from the gas turbine do not trigger any applicable requirements as long as they are below 10 tons per year. Therefore, the OAQ, IDEM specifies the formaldehyde limits in the permits for gas turbine projects based on the comfort level of the applicant in terms of complying with the limit in the permit and restricting the entire source below 10 tons per year which is applicability threshold for new source toxic controls.

The formaldehyde emissions from this entire project are revised as follows. The emission estimates are based on worst case heat input rate at 0^oF ambient temperature.

Two (2) Westinghouse 501 F Combined Cycle turbines (based on emission factor for formaldehyde in Sims Roy memo):

$$\frac{0.000202\ \text{lb}}{\text{MMBtu}} \times \frac{2071\ \text{MMBtu}}{\text{hour}} \times \frac{8760\ \text{hours}}{\text{year}} \times \frac{0.0005\ \text{tons}}{\text{lb}} \times 2\ \text{turbines}$$

= 3.66 tons per year

Two (2) GE LM 6000 Simple Cycle turbines (based on stack test information for similar facility as provided by the applicant):

$$\frac{0.0011\ \text{lb}}{\text{MMBtu}} \times \frac{469\ \text{MMBtu}}{\text{hour}} \times \frac{3500\ \text{hours}}{\text{year}} \times \frac{0.0005\ \text{tons}}{\text{lb}} \times 2\ \text{turbines}$$

= 1.8 tons per year

Combined formaldehyde emissions from all four combustion turbines
= 3.66 + 1.8 = 5.46 tons/year < 10 tons per year.

Therefore, this limit contains enough cushion to limit source wide formaldehyde emissions below 10 tons per year.

The formaldehyde limit for the Westinghouse 501 F combined cycle turbines is revised as follows:

D.1.8 Formaldehyde Limitations [326 IAC 2-4.1-1]

The formaldehyde emission from the combined cycle combustion turbines shall not exceed

~~0.0000705~~ **0.000202** lb/MMBtu. This shall limit the combined formaldehyde emissions from the entire source to less than ten (10) tons per year and make requirements of 326 IAC 2-4.1 not applicable. Any increase in single Hazardous Air Pollutant (HAP) emissions greater than the threshold specified above and combined HAPs greater than twenty five (25) tons per year, from the entire Source must be approved by the Office of Air Quality (OAQ) before such change may occur.

Comment 4:

To protect the stringency precedent of the PSEG Dearborn County PSD Permit 129- 12517-00033 ("PSEG permit"), if a large CT H2CO retreat is done for Acadia Bay permit and the small CT Acadia Bay permit limits and tests are retained; then large CT tests at 50, 75, and 100% power must be performed not less frequently than annually, and the result of each test shall not exceed a calculated rate of 0.123 pounds H2CO per billion LHV BTU.

That is calculated thusly, and rounded up in favor of ABE:
(0.11 x 4 x 1.9064 x 8,768 - 1.13 x 0.423 x 7,000) / 8,768 / 2 / 1.867 = 0.123

The high limit of the small CT's is very contributory. If, for example, their 1.13 limit was reduced to 0.788, then the acceptable limit for the large CT's would be increased:
(0.11 x 4 x 1.9064 x 8,768 - 0.788 x 0.423 x 7,000) / 8,768 / 2 / 1.867 = 0.154

PSEG permit was not issued in a vacuum. It was exposed for public comment. Comment had been made to DEM in re CT H2CO prior to PSEG permit. People elected to not comment on PSEG permit because of the role that it played in re permit attributes and stringency leadership in Indiana. DEM has a reasonable duty to defend the stringency of permit constraints that serve to uphold the synthetic minor source H2CO status of PSEG permit as it issues new permits to sources having CT's who desire H2CO synthetic minor status.

While some may suggest that the PSEG permit H2CO calculated amount:
4 x 1.9064 x 0.11 x 8,768 / 2,000 = 3.68 tpy is overprotective of the 10 tpy threshold of law, there are many facets to view. The threshold is not to be violated and the fact that it has not been violated is to be ascertainable on a more or less continuous basis. DEM typically requires one test (and that may be the only test). There is little solace in PSEG permit D.15(f) language. As response to comment, please list "additional" H2CO tests that DEM has required for CT's having similar language in their permits within the last 3 years.

Roy mentions a difficulty in measuring H2CO continuously and mentions that carbon monoxide ("CO") may play a role as a surrogate. Roy does not suggest a surrogate ratio, does not suggest a linearity of surrogacy over an operating range, and does not deal with operation below 80%. Nonetheless, Roy's CO surrogacy suggestion has some merit.

Response 4:

As explained in the Response 3, unlike other regulated pollutants under 326 IAC 2-2 (Prevention of Significant Deterioration), the formaldehyde emissions do not have to go through Best Available Control Technology (BACT) analysis. Therefore, there is no presumptive BACT for formaldehyde (as stringent as PSEG Dearborn County, identified by the commentator).

The formaldehyde is classified as a Hazardous Air Pollutant under Section 112 (b) of Clean Air Act. Therefore, formaldehyde emissions greater than 10 tons per year trigger requirements of Maximum Achievable Control Technology (MACT).

Historically, based on AP-42 emission factors it was assumed that there are large formaldehyde emissions from gas turbines. Over the years with improvement of combustion technology (development of lean pre-mix combustors), various turbine manufacturers presented information to State and Federal agencies that the formaldehyde emissions were not as high as listed in the AP-42. Based on similar information, California Air Resource Board documented 0.000107 pounds per MMBtu as emission factor for formaldehyde from gas turbines. The estimation of emission factors is based on various stack test information presented to the agencies and their statistical interpretation.

The formaldehyde limit in PSEG Lawrence County permit was based on California Air Toxic emission factor of 0.000107 pounds per MMBtu. As the applicant's proposed emission limit restricts annual formaldehyde emission below 10 tons, the OAQ, IDEM does not have jurisdiction to specify lower limits. The applicants are required to demonstrate compliance with this limit during the first six month of their operation. The testing is to be performed at varying load conditions to capture worst case emissions during the steady state operation of turbine.

In the matter of additional formaldehyde testing, PSEG Lawrenceburg Permit condition D.15(f) states: "IDEM, OAQ retain*(s)* the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary." This is a general statement that is true for any unit permitted by OAQ. It is noted that the current rule cite is 326 IAC 2-1.1-11. The OAQ will review the result of the initial stack test and consider future testing as part of the Part 70 Operating Permit required for this source.

Furthermore, in the matter of CO as surrogate for formaldehyde, the portion of the Sims memo referenced in the comment is actually in the discussion of oxidation catalyst systems on diffusion flame combustor, and is not relevant to the Westinghouse 501 F turbines. The relevant portion of the Sims memo discusses Lean Premix Combustion and notes "For purposes of monitoring HAP performance of lean pre-mix combustor turbines, NOx emission levels characteristic of lean premix combustor technology could be used as an indicator of proper lean premix combustor performance, which in turn would assure proper operation and low HAP emissions."

Comment 5:

There are a blue million (colloquial term) CO numbers within PSEG permit. Trying to look only at the CT CO, here are some observations:

1. If the campus is operated steady- state for a year, then PSEG permit D.1.7(a)(1) seems to suggest a 4 x 21.3 x 8,768 / 2,000 = 373.52 tpy CO value. Is that an enforceable limit?.
2. If the campus is operated start and stop, then PSEG permit D.1.5(d) seems to suggest that for three (3) incredible years, the campus may be operated with *no* CO bound. Is there a federally enforceable CO permit bound for those 3 years? If so, what is the annual limit and how is it enforceable as a practical manner?
3. The LPTE table on Page 1 of Appendix A to the PSEG permit TSD has a 420.95 tpy CT CO value for normal operation and an *additional* 605.54 tpy CT CO allocation for start-up and shutdown operation. Are either of those figures federally enforceable CO bounds as they are not in the "permit" text?

There is obviously disparity (373.52 v. 420.95) in those numbers, but for the sake of argument, ratios of the point 3 numbers may be applied to the PSEG permit H2CO calculated as if CO was a linear surrogate: 4 x 1.9064 x 0.11 x 8,768 / 2,000 x (420.95 + 605.54) / 420.95 = 8.97 tpy H2CO— something that is nowhere near overprotective of the 10 tpy threshold of law.

Running that ratio with the 373.52 figure:
4 x 1.9064 x 0.11 x 8,768 / 2,000 x (373.52 + 605.54) / 373.52 = 9.64 tpy H2CO— something that is far closer to directly exceeding the 10 tpy threshold of law.

Response 5:

The PSEG Lawrenceburg permit was issued on June 7, 2001. This addendum to the TSD is specific for the comments and changed on the Acadia Bay proposed permit only.

Comment 6:

Please explain in detail all of the measurement mechanics and calculations of a H2CO test. As I visualize it:

1. A volume of composite stack gas is analyzed for H2CO, and the answer is likely a mass per unit volume.
2. A volume per unit time measurement is made for the whole stack— with the temperature and pressure *identical* to that of the point 1 sample.
3. A gas fuel flow meter may give a number, such as thousands of scf per minute.
4. An analysis of the gas for its specific chemical higher heating value in BTU / scf is factored.

There are many other possibilities. For example, the first analysis might give a mass H2CO per total mass of the sample and the second factor might be a stack gas mass per unit time....

> "For the above, supply the mathematical and statistical basis for uncertainties of *each* portion and a cumulative multiplicative error. A technical answer is to be supplied, not the empty and philosophical brush-off as presented in response to a simpler matter in PSI Hamilton County 40 CFR 70 Modification 057- 14278- 00004 ATSD page 2."

Response 6:

While there are currently no promulgated reference methods for formaldehyde. The U.S. EPA and IDEM would agree the following method:

(a) A sample of stack gas is passed (bubbled) through a set of impingers (water filled glass bottles). Since Formaldehyde is highly soluble in water it will be collected in these impingers. These impingers are recovered and the water is transferred to a common container where a sample is taken and reacted with acetyl acetone. This will produce a known color change, which can be measured and quantified by spectroscopy.

(b) This will give concentration in whatever unit is needed: parts per million (ppm), milligram per dry standard cubic meter (mg/dscm), etc.

(c) Flowrates can then be measured in the stack using EPA reference methods 1-4. This will give the airflow which can be multiplied by the concentration to give lbs/hr.

(d) By measuring the amount of natural gas burned (in cubic feet) and then multiplying that by the Btu value of a cubic foot of gas (1050), the total heat input to the turbine can be calculated. Then the lbs/hr of formaldehyde is divided by the heat input to get lbs/MMBtu of Formaldehyde.

(e) Alternatively, the 'F' factor specified in Appendix A of 40 CFR 60, Method 19 can be used to calculate pounds per million Btu of formaldehyde emissions.

Comment 7:

To say that there is more than an ample possibility that the errors associated with those measurements multiplied may cumulate and cause the 10 tpy threshold to be passed is an understatement. Allowing 6, 6, 0.6, and 0.6 percent error respectively for the 4 points would lead to: 8.97 x 1.06 x 1.06 x 1.006 x 1.006 = 10.20— a violation.

Recognizing that only a single test is specified (it should be done not less than annually), a considerable safety margin is warranted as there is considerable measurement uncertainty in steady- state conditions, expectations that equipment will degrade over time (i.e. there will be deposition of solids on various combustion pathways which will be subject to perhaps annual maintenance and there will be erosion of various components which will likely be tolerated for several years prior to restoration), etc. Absent a very exhaustive continuous test regimen on similar equipment that incorporates all ranges of operations from initial start to complete stop, the amount of H2CO, particularly the amount generated in the start, idle and stop phases is unknown. What is known is that it is that H2CO per unit fuel ratios it rise dramatically as net power levels are decreased.

For those reasons, it is appropriate to apply equally protective stringency to Acadia Bay permit H2CO as was applied in PSEG permit.

Thus, the calculated large CT 0.123 pounds H2CO per billion LHV BTU emission rate (above) if there would be a retreat from 0.0705 that is in the Acadia Bay permit draft.

As an alternative to the PSEG permit equivalent methodology and stringency, or retaining the Acadia Bay permit draft stringency, ABE may freely apply for a permit amendment and incorporate continuous emissions monitoring ("CEM") for H2CO that will allow the calculation of an annual average rolled daily. If, for example, they installed equipment that gave recorded values that were within ± 5% of the actual H2CO amounts for all four CT's, then they would be entitled to permit limits for the CT's in the drafts that totaled about 9.5 tpy. And, as long as they did not violate the annual rate, they could, for example, freely emit 9 tons of H2CO in 6 months.

Response 7:

The OAQ, IDEM has reviewed the possibility of errors in measurements during stack test in the past. During the evolution of stack test protocol it was shown that as the measure of error is both positive and negative in some percentage (±6 % as suggested by the commentator), it can work both for and against the project applicant. Therefore, there is the same chance of the applicant emitting more as there is chance for emitting less than what is being recorded.

In addition, as noted on the Response 3, the annual formaldehyde emissions based on the emission limits in the permit will not exceed 5.46 tons during the steady state operation. The OAQ, IDEM concurs with commentator that enough documentation of formaldehyde emissions during startup, shutdown and part load condition is not available at the moment. But enough cushion is available to leave an allowance for the uncertainty die to these conditions.

As noted in the 2001 Sims Roy memo and the Response to Comment 12, the NOx emission levels are considered to be an indicator of proper lean premix combustor performance, which in turn should assure proper operation and low HAP emissions. The NOx and CO CEMS are subject to annual certification.

OAQ has the authority to request stack testing whenever it is determined to be necessary to demonstrate compliance with an applicable requirement. One possible scenario is when the quarterly NOx and CO reports indicated that a unit is not operating properly, OAQ could request additional formaldehyde testing to confirm the compliance status of the unit. The EPA Clean Air Markets Division does not recommend CEMS for formaldehyde.

Comment 8:

CO v. H2CO — surrogacy

H2CO and CO are both products of incomplete combustion. Roy has suggested a surrogate relationship. It is well within the discretionary power of DEM to order a low-cost test when a high-cost test is performed. Therefore, Acadia Bay permit D.1.13(b) and D.2.12 should be amended to require that whenever a H2CO test is performed, a sufficient sample shall be taken such that a CO test can be performed with a percentage accuracy greater than the H2CO percentage accuracy but in no way compromising or degrading the H2CO test accuracy. Each test pair data point should then be posted on the DEM web site, such that all may benefit from it. Obviously the units for the 2 chemicals must be the same.

Great care should be exercised to not post unpaired data there. For example, while a facility, having a "permanent" CEM for CO functioning, is attempting to operate "steady- state," at the time a H2CO test is being performed with "temporary" equipment, there would be a temptation to use the CEM CO result rather than an independent test of the same composite that is being used for the H2CO test. That data should *not* be entered into the pair database as the tests were performed on different samples.

The importance of excluding unpaired data cannot be overstated, as unpaired data is the basis for the "d" footnote to EPA AP-42 Table 3.1-1 (April 2000) and, no doubt, unpaired data is the reason for the hexane debacle.

Response 8:

The OAQ, IDEM concurs with the commentator about developing correlation between the NOx or CO and formaldehyde emissions from the gas turbines. In the future, stack test information regarding the emissions from the gas turbines at merchant power plants becomes available, the OAQ, IDEM will compile results and use it in future permitting for similar facilities.

Comment 9:

CO — carbon monoxide BACT

DEM proposes in the *first* "page 1 of 1" of Appendix A to the Acadia Bay permit TSD to permit ABE to emit 116.38 + 14.60 = 130.98 tpy of CO from the small CT's. Acadia Bay permit D.2.5(b) states 116 tpy, but is says "turbine" (singular) and Acadia Bay permit D.2.10(c) gives rise to the 14.60 tpy portion. D.2.5 must be amended to make clear that the 116 tpy is the sum of the small CT's.

Response 9:

The condition D.2.5 has been revised to show that the 116 tons of CO emissions limit is for both simple cycle combustion turbines as follows:

D.2.5 Carbon Monoxide (CO) Emission Limitations for Simple Cycle Combustion Turbines [326 IAC 2-2]

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

(1) During normal simple cycle operation (seventy (70) percent load or more), the CO emissions from each simple cycle combustion turbine shall not exceed limits in following table corrected to 15% O_2 on a 24 operating hour averaging period.

Ambient temperature range	CO emissions concentration in ppmvd at 15% O_2
Greater than 70^oF	25
From 30^oF to 70^oF	50
From 0^oF to 30^oF	75
Less than 0^oF	100

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

(3) Use natural gas as the only fuel

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual CO emission from the simple cycle combustion turbine**s**, excluding startup and shutdown emissions, shall not exceed 116 tons per year.

Comment 10:

Page 1 of Appendix A to the Duke Knox County PSD Permit 083- 12674- 00043 ("Duke, 12674") TSD shows 517.63 + 123.62 = 541.25 tpy of CO. Yet this permit texts D.1.6(b) and D.1.4(c) give rise to 539.60 + 123.2 = 662.80 tpy CO.

Contrast Duke, having Duke Knox permit A.2(a): 8 x 1.158 x 20,665 / 22,931 = 8.3485 billion LHV BTU / hour of simple- cycle equipment being permitted 663 tpy of CO to ABE planning:
2 x 0.423 = 0.846 billion LHV BTU / hour of simple- cycle equipment having 130 tpy of CO in the Acadia Bay permit draft.

Contrast Duke, having the total cost of their site with ABE putting their small CT's on a site with their other equipment. Compare the incremental cost for Duke for staff visitation v. ABE having staff a short walk away.

Best Available Control Technology ("BACT") has an economic obligation (42 USC 7479(3), 40 CFR 52.21(b)(12)). ABE is getting, for their small CT's, many attributes of staff transportation and simply staff proximity for a tiny fraction of Duke's cost. Similarly, as a result of sharing with the other ABE equipment, the additional land and perimeter for ABE's small CT's, on a per MW basis, is tiny compared with Duke's.

Duke Knox permit D.1.6(a)(1) constrains Duke to a 25 parts per million by volume on a dry basis corrected to 15% O2 ("ppm") CO emission concentration. In Acadia Bay permit D.2.5(a)(1), ABE is permitted 100 ppm.

Yes; the Duke and ABE equipment cost is different. What is the cost of the equipment (per MW)? Is not the cheaper equipment more polluting?

DEM did not consider equipment cost, site cost, staff transportation cost, staff proximity cost when it did its Acadia Bay permit BACT analysis. That is a abuse of discretion. The BACT analysis is faulty, and DEM simply gave ABE a free ride.

There is no rational whatsoever for giving ABE a
(130.60 x 8.3485 / 0.846 / 662.80 -1) x 100 = 94% greater right to emit CO than Duke.

DEM must rewrite the Acadia Bay permit small CT CO limits to not exceed
662.80 x 0.846 / 8.3485 = 67.17 tpy CO annual limit for the combination of the small CT's.

Response 10:

The Duke Knox County project permit 083-12674-00043 use General Electric 7 EA Frame type turbines that are rated at 109 MW and have Dry Low NOx combustors. The Acadia Bay simple cycle turbines are General Electric LM 6000 aero-derivative type turbines and generate only 46 MW. The difference between Frame type and aero derivative type turbines is explained in detail in the Appendix C the BACT analysis for NOx and CO for the simple cycle turbines. The differences are further highlighted as follows:

GE 7 EA Frame Type in Duke Knox Project	GE LM 6000 aero derivative in Acadia Bay
Large turbine with maximum electricity production rate of 109 MW	Small air craft engines connected to generators with maximum electricity production rate of 46 MW
Unlimited on hours of operation on annual basis	Limited to 7000 hours of combined operation for two turbines (3,500 hours each)
Emission limit of 25 ppm for CO is well documented and demonstrated by tests	The emission limit for CO is in the range of 60-70 ppm for CO without add on controls

One important aspect is the ambient temperature and CO emission rate relation as shown in condition D.2.5 in Response 9. As the ambient temperature decreases the CO emissions from gas turbines increase. As explained in the BACT discussion, even though a higher CO emission limit is provided for operation below 30°F, the days when the 24-hour average temperature dips below 30°F are rare. For ambient temperature greater than 30°F, the CO emissions limit is comparable to other similar facilities (using GE LM 6000 turbines) at 50 ppm. Therefore, Duke's 25 ppm CO emission limit is not comparable to Acadia Bay's simple cycle aero derivative turbine's CO emission limit.

Therefore, the CO emissions levels are inherent to the size and type of turbine selected. Permit conditions are imposed for the purpose of ensuring that each proposed project that will emit pollutants at major levels uses emission control systems that represent BACT, thereby reducing the emissions to the maximum degree possible. The permit conditions that define these systems are imposed on the project as the applicant has defined it. The conditions are not intended to redefine the project. OAQ has no authority to require the applicant to install a different size of turbines than what is being proposed. This permit's CO limits are currently considered to be BACT for CO for this size of simple cycle turbines.

Comment 11:

Rios — the brush-off

The USEPA Region 9 19 June 2001 letter from Rios to Dixon ("Rios" attached hereto and incorporated herein) says presumptive CO BACT is 2.0 ppm 3-hour average. DEM did not show cause why that limit should not apply to the ABE large CT's in the Acadia Bay permit draft. DEM did not show cause why that limit should not apply to 12432 in the 12432 draft or in the 12432 issued permit where Rios had been made available to DEM as comment.

DEM evaded: 'We are tough on NOx, give us a break on CO' (response 3, 12432 ATSD page 16), there, DEM admonishes the commentor (me) for overlooking DEM's NOx stringency, "What the comments failed to mention...." Rios is unmentioned by name by DEM in the published response, and DEM fails to mention that Rios presumes NOx BACT is 2.0 ppm 1 hour average while it issued 12432 D.1.6(a)(1) at 3 ppm NOx 24-hour average and it proposes Acadia Bay permit D.1.3(a)(1) at the same 3 ppm NOx 24-hour average which would allow somewhat more than 50% more average NOx concentration than Rios.

DEM alleges Rios 2.0 ppm CO is for oxidation catalyst control. DEM fails to mention that tested lean premix combustion CT's have produced less than 0.6 ppm CO with no catalyst. It is just and proper to give a large limit to assure that a source may reasonable not violate it. Giving a cushion factor of three may be justifiable in limited circumstances— DEM's Acadia Bay permit D.1.1(a)(1) giving a cushion factor of more than ten makes a mockery of BACT. That is a gross abuse of discretion.

Further, Rios suggests that 5 ppm ammonia ("NH3") is achievable for the 2 ppm NOx concentration. DEM, in PSD permits: Whiting Clean Energy Lake County 089- 11194- 00449 ("11194") (issued), Mirant Vigo County 167- 12208- 00123 (issued), 12432 (issued), Duke Vigo County 167- 12481- 00125 (issued), MVE Posey County 129- 12750- 00016 (draft), PSEG permit (issued), and Acadia Bay permit (all for CT's with Selective Catalytic Reduction NOx control) has put forth a 10 ppm "NH3" mantra with no technical basis whatsoever for why lower NH3 concentrations are not both achievable and reasonable in permit limits.

While Rios is in USEPA Region 9, the people of Region 5 have every bit as much of a right to the cleaner air that would come from the Rios CO, NOx, and NH3 lower emission rates and shorter averaging times.

Response 11:

The commentator has submitted a letter to the OAQ, which is addressed to Mr.David Dixon of San Luis Obispo Air Pollution Control District from Gerardo Rios of US EPA, Region IX. In this letter Region IX has commented on Duke Energy Morro Bay permit as follows:

(a) NOx limit should be 2.0 ppmvd on 1 hour rolling average
(b) Ammonia Slip should be limited to 5 ppmvd
(c) CO limit should be 2.0 ppmvd on 3 hour rolling average

The OAQ, IDEM does not agree with commentator's observations. This is explained as follows:

1. The NOx emission limit proposed in the draft permit for Westinghouse 501 F turbines in this permit is 3.0 ppm @ 15% O2 on three (3) hour block average period.

2. This limit is not based on 24 hour average basis as suggested by the commentator in his written comment.

3. The OAQ, IDEM updated its information base of BACT determinations for gas turbine projects during the public comment period for this permit. Additional information was also obtained regarding recent stack tests at similar sources in other states. It was found that the NOx emissions after the SCR control system varied from 1.5 ppm to 2.5 ppm @ 15% O2 in the exhaust.

   The OAQ, IDEM has required to revise the NOx emission limit for the Westinghouse 501 F turbines to 2.5 ppm @ 15% O2 on a 3 hour block average basis. The condition D.1.3 in the permit is revised as follows:

D.1.3 Nitrogen Oxides (NO_X) Emission Limitations for Combined Cycle Combustion Turbines [326 IAC 2-2]

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

   (1) During normal combined cycle operation (seventy (70) percent load or more), the NO_X emissions from each combined cycle combustion turbine stack shall not exceed ~~3.0~~ **2.5** ppmvd corrected to fifteen (15) percent oxygen, based on a three (3) hour block average period, which is equivalent to ~~22.4~~ **18.7** pounds per hour.

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

   (3) 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.

   (4) Use natural gas as the only fuel.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the annual NO_X emission from the combined cycle combustion turbine, excluding startup and shutdown emissions, shall not exceed ~~170.87~~ **142.91** tons per year.

4. The review of stack test information for some newer similar sized turbines shows that NOx emissions are below 2.5 ppm @ 15% O2 but do reach above 2.0 ppm @ 15% O2. Therefore, NOx level of control below 2.0 ppm @ 15% O2 is not currently demonstrated in the field.

5. This limit is comparable to BACT determinations for this type of source in other states in Region 5 of EPA and other Regions. This limit is slightly higher than the limit proposed in the California permit for similar type of Source. In a document approved by California Air Resource Board (CARB) on July 22, 1999, "Guidance for Power Plant Siting and Best Available Control Technology, CARB has stated on page 6 "Most BACT definitions in

California are consistent with the federal LAER definition and are often referred to as 'California BACT'. One should take note not to confuse 'California BACT' with the less restrictive federal BACT. As this is a federal PSD BACT review the permit limits are less stringent than 'California BACT' but equal or more stringent than other federal BACT determinations are appropriate.

6. The CO limit for Westinghouse 501 F turbines in this permit is at 6.0 ppm @ 15% O2 on a 24 hour block average basis.

7. See discussion on BACT/LAER in point 5 above. Further, there is a large variation in CO emissions due to variations in the ambient temperature. As the ambient temperature falls, the CO emissions from the turbines increase. The turbines in Indiana will be subject to much lower temperature conditions than the turbine projects in California.

8. The OAQ, IDEM has reassessed similar other sources that had received permits after the public comment period for this permit had started.

   The CPV Pierce Ltd. in Florida received permit in August 2001 for 1 GE 7 FA turbine in combined cycle mode with SCR for NOx control. The limits for various pollutants are compared to Acadia Bay permit as follows:

	Pollutant	CPV Pierce Ltd.	Acadia Bay
1.	NOx	2.5 ppm @ 15% O2 on a 24 hour block average	2.5 ppm @ 15% O2 on a 3 hour block average
2.	CO	8 ppm @ 15% O2 on a 24 hour block average	6 ppm @ 15% O2 on a 24 hour block average
3.	NH3 Slip	5 ppm @ 15% O2	10 ppm @ 15% O2 on a 3 hour block average

   The limits proposed for Acadia Bay permit for the combined cycle operation compare favorably to CPV's permit limits. The NOx limit for Acadia Bay is same but on a shorter 3 hour block average basis is more stringent than 24 hour block average for CPV permit. The CO limit is lower than the CPV permit.

   The Acadia Bay permit has a higher ammonia slip limit because, with a shorter averaging period for NOx, the ammonia slip may increase to keep the NOx emissions below 2.5 ppm @ 15 O2. The OAQ feels that the NOx limit of 2.5 ppm @ 15% O2 is protective of the environment and human health. The use of three operating hour average emission rate protects the NAAQS for NOx on annual basis.

Comment 12:

<u>Start-up BACT — DEM did no analysis</u>

A rather substantial point made by USEPA (above regional) and USEPA Region 5 in re BACT for Steel Dynamics in their 20 December 1999 joint Amicus brief to the USEAB (incorporated herein by reference) was that BACT shall apply at all production levels. ABE's product is electrical energy, and "production" obviously begins to occur at well less than 100% load. A reasonable point for defining when it begins to occur for a specific CT would be when the mechanically connected specific generator is producing 10% of nominal load.

DEM performed no BACT analysis whatsoever for low load conditions, rather it simply threw a batch of overly generous, non-environmentally protective start-up and shutdown allowances far above the 100% load per unit time for NOx, CO, PM10 into the permit with no technical explanation whatsoever (in the Acadia Bay permit published draft package) as to the origin of those allowances or as to why lower limits are not achievable.

DEM explored no control technique whatsoever (such as Selective Catalytic Reduction ("SCR") catalyst pre-heating) for these operating ranges.

It appears that ABE said, 'give us this' and DEM said 'OK, fine.'

Not performing a BACT analysis for *all* levels of production is a gross abuse of discretion.

Response 12:

The OAQ, IDEM disagrees with the commentator that the BACT analysis for non-steady (startup/shutdown) operation was not performed. The BACT is a case by case determination, which takes into account peculiarities of particular project when comparing it to other similar source.

The effectiveness of CO catalyst was taken into account while assessing the control options for CO emissions during startup and shutdowns. The Selective Catalytic Reduction system works on feedback loop system. The monitor in the exhaust after the SCR reads the NOx emission rates and activates the ammonia injection to control the NOx emissions. During the non-steady state operation (operating loads less than 70% during Startup and Shutdowns), the rate of NOx emissions and flow rate of exhaust gases is extremely varying. As a result the feedback system will not be able to keep a steady flow of ammonia and will risk exceeding the ammonia slip limit on this system. Therefore, SCR system will not be able operate effectively during non-steady state operation.

The permit does contain limitations in the form of pounds of emissions per startup and shutdown. The permit also contains a limitation on annual hours of startup and shutdown to limit the number of hours of non-steady state operation. As non-steady state is a transient stage and no other examples of controlling emissions during this stage has been observed, the OAQ, IDEM believes that the limitations contained in condition D.1.10 and D.2.10 are BACT for these processes.

Comment 13:

<u>NH3 — its use, its abuse</u>

It is no industry secret that the flow of NH3, as reagent intentionally admitted into the NOx SCR pollution control system, is analog rather than digital. A variety of sensors give information to a computer, which regulates the NH3 flow. One or more pyrometers, giving a temperature reading of the catalyst surface temperature is a reasonable input. In Acadia Bay permit D.1.3(a)(3), DEM has allowed the non-use of pollution control equipment during each start and shutdown. Further, those phases are defined in D.1.10 excessively liberally in terms of time and NOx quantity. I.e. 1,078 pounds NOx per 4.16 hours for 2 large CT's combined for start-up and shutdown v. 186.4 pounds NOx per 4.16 hours for 2 CT's combined for normal operation.

The difference between SCR NOx pollution control and selective non-catalytic reduction ("SNCR") ... is that of the catalyst. The reactions; breaking the NOx and NH3 molecules and recombining the elements into water, nitrogen, and oxygen (all as gases); are the same for both SCR and SNCR. The catalyst causes the reaction to begin at a lower temperature. NH3 is a flammable gas that adds energy to the system. Once the reaction starts at the lower point where the catalyst is effective, it increases due in part to the effect of this added energy.

DEM was exposed to similar comment in 12432, and its response, power level criteria, is not acceptable. This chemistry is firmly related to quantifiable temperature, and it is not very related to quantifiable time or power level. The permit must be rewritten to require NH3 reagent use at all times whenever there is NOx present in reactable concentrations and the SCR catalyst is within an effective temperature range. To intentionally permit non-use of pollution control equipment under physical conditions where it would be effective and it is available is direct evasion of Best Available Control Technology, which is an abuse of discretion by DEM.

Acadia Bay permit D.1.10 allows "slip" of poisonous gas NH3 at the rate of 10 ppm @ 15% O2. 2

ppm is what Massachusetts imposes. This permit gives no mention of the maximum permitted annual NH3 emission. While NH3 is not a legal HAP or a criteria pollutant, it is a poisonous gas, and, as such, the emission of it is reasonably something that the permit should clearly disclose.

The Acadia Bay permit control appears to be D.1.13(b), one stack test having no load parameters. As the catalyst degrades over time, ABE will create a super-surplus of the stoichiometric reagent amount in order to achieve suitable NOx levels prior to catalyst replacement. NH3 testing must be required not less frequently than annually and at 50, 75, and 100% load.

DEM reasonably owes the People a clear calculation of the annual emission of poisonous gas, NH3, designated in Appendix A to 40 CFR 355 as an "Extremely Hazardous Substance," and if that emission is not limited and if there is no law, regulation or rule, then those facts should be made clear. DEM should provide rationale and "where you are on the curve" as far as if the operation is adjusted, such that 2,000 less pounds per year of NH3 would be emitted, then what is the pounds per year change in NOx believed to be. And DEM should provide rationale for NOx control v. NH3 emission environmental and health benefit tradeoffs.

Response 13:

The Selective Catalytic Reduction system works on feedback loop system. The monitor in the exhaust after the SCR reads the NOx emission rates and activates the ammonia injection to control the NOx emissions. During the non-steady state operation (operating loads less than 70% during Startup and Shutdowns), the rate of NOx emissions and flowrate of exhaust gases is extremely varying. As a result the feedback system will not be able to keep a steady flow of ammonia and will risk exceeding the ammonia slip limit on this system.

The load on the turbine reaches 70% of the maximum load within 3 hours and 50 minutes (worst case for cold start) from the time of initial start. At this stage the exhaust flow rates are stable and the temperature of the exhaust gases reaches the optimum temperature range for the catalyst. At this stage the ammonia injection can start to control NOx emissions from the turbine.

Annual Ammonia emission limit is added in condition D.1.9 as follows:

D.1.9 Ammonia Limitations [326 IAC 2-1.1-5]

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

(a) **shall not exceed ten (10) ppmvd corrected to 15% O_2 on 3 hour block average basis, and**

(b) **shall not exceed 226 tons per calendar year.**

A new condition D.1.14 for determination of optimum temperature for operation of SCR is added as follows:

D.1.14 Oxides of Nitrogen NOx (SCR operation) [326 IAC 2-2]

(a) Pursuant to 326 IAC 2-2 (PSD requirements), the Permittee shall determine optimum temperature of the catalyst bed during the stack test requirement in condition D.1.13 (a) (d) that demonstrates compliance with limits in condition D.1.3, as approved by IDEM.

(b) From the date of the valid stack test, during a startup, the Permittee shall start ammonia injection in the SCR units to control NOx emissions from the gas turbines, as soon as the catalyst bed reaches the temperature determined in part (a) above or turbine load reaches 70%, whichever occurs earlier.

The subsequent conditions in Section D.1 have been renumbered.

Comment 14:

CEM's

Acadia Bay permit D.1.15(b) and D.2.14(b) have "shall maintain" language following certification of CEM's. The calibration and performance of the equipment will degrade with time.
A requirement that the equipment be recertified not less frequently than annually is needed to show continuous compliance with the best available control technology limits on emissions rates and totals.

Response 14:

Acadia Bay permit Condition D.1.15(b) and Condition D.2.14(b) require the Permittee to install, calibrate, certify, operate and maintain a continuous emissions monitoring system for NO_X and CO in accordance with 326 IAC 3-5-2 and 3-5-3.

Except where 40 CFR 75 has applicable CEMs for affected facilities under the acid rain program, the quality assurance requirements of 326 IAC 3-5-5 and 40 CFR 60 Appendix F are applicable to continuous emission monitoring systems (CEMS) that monitor CO2, CO, H_2S, NOx, O_2, SO_2, total hydrocarbons, total reduced sulfur, or volatile organic compounds. There are no CEM requirements in the acid rain provisions that are applicable to combustion turbines. Therefore, 326 IAC 3-5-5 is applicable to these units. 326 IAC 3-5-5(d) does require an annual relative accuracy test (RATA) for the flow monitoring system.

To clarify that the standard operating procedures of 326 IAC 3-5-4, quality assurance requirements of 326 IAC 3-5-5, record keeping requirements of 326 IAC 3-5-6, and reporting requirements of 326 IAC 3-5-7 are all requirements for the CEMS, the rule citation has been changed in Acadia Bay permit Condition D.1.15(b) and Condition D.2.14(b), as follows:

D.1.15 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 continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO, for stacks designated as 1 and 2 in accordance with 326 IAC 3-5-2 ~~and 3-5-3~~ **through 326 IAC 3-5-7**.

D.2.14 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 continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emission monitoring system for NO_X and CO, for stacks designated as 3 and 4 in accordance with 326 IAC 3-5-2 ~~and 3-5-3~~ **through 326 IAC 3-5-7**.

Comment 15:

NOx — nitrogen oxides

The *first* "page 1 of 1" of Appendix A to the Acadia Bay permit TSD LPTE table lists 76.013 tpy start-up and shutdown NOx for the large CT's. Acadia Bay permit D.1.10(d)(i) allows
210 x 1,078 / 2,000 = 113.19 tpy start-up and shutdown NOx, and the 1,078 figure should be changed to 723.9 prior to issuance.

Response 15:

The emissions during startup and shutdown for the combined cycle turbines are estimated based on 70 Cold, 70 Warm and 70 Hot startups as shown on page 4 of 11 of Appendix A. The NOx emissions during hot start are approximately 34% of the emissions during cold start. Therefore, the estimated emissions during startup and shutdown are based on operation scenario as presented by the applicant. The NOx emission rate of 1,078 pounds per startup and shutdown cycle (called as an event in the permit) is based on manufacture's performance spec for this model of turbine (Westinghouse 501 F), in a power block consisting of two turbines.

No changes are made to any permit conditions.

Comment 16:

<u>HHV LHV</u>

DEM must provide appropriate HHV LHV prefixes throughout the entire Acadia Bay permit document package.

Response 16:

The appropriate changes to reflect higher heating value vs lower heating value have been carried out as shown in Response 1 of this document.

Comment 17:

<u>Hexane</u>

DEM must cease propounding fraudulent HAP data upon the People. DEM must, in the Addendum to the Acadia Bay permit TSD as response to comment, purge all references in the Acadia Bay permit draft where hexane is mentioned, and, for all tables in the Acadia Bay permit draft where hexane played a role in the HAP computation, provide new tables sans hexane. In addition to H2CO, which is reasonably believed to be the most dominant by mass HAP, DEM reasonably owes the People a scientifically sound identification, PTE, and LPTE for the *second* most dominant HAP for the two groups of CT's and the boiler individually and in concert. And DEM must alter all tabular data accordingly.

The PTE and LPTE "total HAP" should be reported conservatively based on the H2CO, such as a 12:7 ratio and a footnote should be added stating that the total HAP is clearly unknown, that the value presented is a conservative estimate and not a total of speciated estimated components, and that governing law is believed to be the 10 tpy single HAP threshold.

For example, to get the PTE for the four CT's, I'd use Roy's 95th percentile for the large CT's and the draft limit for the small CT's:
(0.202 x 22,931 / 20,665 x 1.867 + 1.13 x 0.423) x 2 x 8,768 / 2,000 = 7.84 tpy H2CO single HAP PTE and 13.44 tpy estimated HAP PTE total.

To get the LPTE for the four CT's, I'd use:
(0.0705 x 1.857 x 8,768 + 1.13 x 0.423 x 3,500) x 2 / 2,000 = 2.83 tpy H2CO single HAP LPTE and 4.85 tpy estimated HAP LPTE total.

I'd increase all 4 numbers about 0.01 tpy for the boiler. I'd report a very roughly estimated 0.14 tpy LPTE of acetaldehyde and put in a 100-word paragraph that spoke of the lack of data and lack of data quality. I'd be very nervous about calling benzene (or any other non-oxygen containing cyclic) the third most dominant HAP.

Until DEM scientifically states the PTE and LPTE for *every* HAP more dominate by mass than hexane, DEM should not mention hexane.

<u>H2CO</u>

If a large CT H2CO retreat is done for Acadia Bay permit and the small CT Acadia Bay permit limits and tests are retained; then large CT tests at 50, 75, and 100% power must be performed not less frequently than annually, and the result of each test shall not exceed a calculated rate of

0.123 pounds H2CO per billion LHV BTU.

If DEM allows a post-draft retreat of large CT H2CO to less than PSEG permit equivalent stringency, then that is an abuse of discretion.

CO v. H2CO — surrogacy
DEM should establish a H2CO and CO test pair database, and if the H2CO tests have not been done per 11194 D.1.13(c)(4), then Whiting should be the first contributor to the database. This requirement should be imposed on all sources where a H2CO combustion product test is done.

Response 17:

The changes referenced above have been discussed in Response 2, 3, 4, 6, 7 and 8 above. A revised potential to emit showing HAP emissions is show below. No change will be made to the original TSD. The OAQ prefers that the TSD reflect the permit that was on public notice. Changes to the permit or technical support material that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result of ensuring that these types of concerns are documented and part of the record regarding this permit decision.

HAPs	Potential To Emit (tons/year)
Single HAP (Formaldehyde)	7.27
Combination of HAPs	16.98

Comment 18:

CO — carbon monoxide BACT
BACT has an economic obligation. (42 USC 7479(3), 40 CFR 52.21(b)(12)). DEM must consider equipment cost, site cost, staff transportation cost, staff proximity cost and do a proper BACT analysis for the Acadia Bay permit small CT's. DEM must rewrite the Acadia Bay permit small CT CO limits to not exceed a 67.17 tpy CO annual limit for the combination of the small CT's.

Granting ABE a huge BACT CO bonus for its small CT's, used for peaking, compared with Duke Knox permit size and economics is an abuse of discretion.

Response 18:

The CO BACT determination for GE LM 6000 simple cycle turbines has been discussed in detail in Response 9 and 10.

Comment 19:

Rios
DEM must implement the Rios NH3 and NOx limits and averaging times or show conclusive technical reason why ABE should not be so obligated.

DEM must implement the Rios CO limit and averaging time or show conclusive technical reason why ABE should not be so obligated. In re CO, DEM shall not raise the oxidation catalyst matter as a straw issue as lean premix CT CO tests of less than 0.6 ppm have been achieved.

Not implementing Rios and not providing sound science is an abuse of discretion.

Response 19:

The Rios memo has been discussed in detail in Response 11.

Comment 20:

Start-up
DEM must perform a complete BACT analysis for all levels of production. "Production" must be defined as being a very low level of load. Control techniques related to low level operation must be evaluated. Failure to perform the required BACT analysis is an abuse of discretion.

NH3
DEM must disclose a potential to emit and it must lower the emission concentration to 2 ppm. DEM has provided no technical basis for why a 10 ppm value has merit.

The permit must be rewritten to require NH3 or equivalent reagent use at all times whenever there is NOx present in reactable concentrations and the SCR catalyst is within an effective temperature range.

The permit must require testing not less frequently than annually and at 50, 75, and 100% load. DEM reasonably owes the People a clear calculation of the annual emission of poisonous gas, NH3, designated in Appendix A to 40 CFR 355 as an "Extremely Hazardous Substance," and if that emission is not limited and if there is no law, regulation or rule, then those facts should be made clear. DEM should provide rationale and "where you are on the curve" as far as if the operation is adjusted, such that 2,000 less pounds per year of NH3 would be emitted, then what is the pounds per year change in NOx believed to be. And DEM should provide rationale for NOx control v. NH3 emission environmental and health benefit tradeoffs.

Not requiring NH3 or equivalent reagent use for NOx control in the SCR equipment at all times whenever there is NOx present in reactable concentrations and the catalyst is within an effective temperature range is an abuse of discretion.

Response 20:

The comments on startup emissions and ammonia usage has been dealt with in Response 12 and 13.

Comment 21:

CEM's
Amendment to Acadia Bay permit D.1.15 and D.2.14 is needed to require that the equipment be recertified not less frequently than annually to show continuous compliance with the best available control technology limits on emissions rates and totals.

Response 21:

The CEMs conditions have been revised as described in Response 14.

Comment 22:

NOx
Acadia Bay permit D.1.10(d)(i) must be amended from 1,078 to 723.9 prior to issuance.

Response 22:

The emission calculation for Startup/shutdown duration are explained in Response 15.

Public Hearing

On November 7, 2001, a public hearing was held in the Town of New Carlisle with respect to the draft air construction permit for Acadia Bay Energy Co. LLC. Following individuals spoke during this public hearing:

1. Stephen Loeschner
2. Steve Hora

These comments and the OAQ, IDEM responses are documented in the following pages.

Stephen Loeschner

Comment 1:

He presented the notice of violation EPA 5-01-IM-13 issued by US EPA to Steel Dynamics (SDI) of Butler Indiana. It stated that based on a PSD permit issued in 1994, the NOx emissions from the electric arc furnace (EAF) at SDI were limited to 0.51 pounds per ton of steel. In July 1996 stack test the EAF NOx emissions were tested at 1.34 pounds per ton of steel. The notice of violation to this source was issued this year approximately after five years from the date violation was first established by the federal agency. According to commentator there is no enforcement in the State of Indiana.

Further, in condition C.15, (c) it states as follows: "-- After investigating the reason for the excursion, the Permittee is excused from taking further response steps for any of the following reasons. --" (2) "The Permittee has determined that the compliance monitoring parameters established to 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".

This language in sub paragraph (2) should be deleted so that Permittee is not to be excused from taking response steps, just by sending in a letter stating they cannot meet the limit.

Response 1:

The Acadia Bay permit requires the Source to install the Continuous Emission Monitoring (CEMs) on the exhaust from the turbines to monitor NOx and CO emissions. The breakdown of the CEMs equipment is covered in condition C.13 (Maintenance of Monitoring equipment). The condition C.15 applies to the compliance monitoring plan for equipment that uses parametric monitoring in place of CEMs to show compliance and is not applicable to this permit.

The condition C.15 is part of the general conditions for the permit draft. It was inadvertently included in this permit. The OAQ, IDEM has deleted the condition C.15 (c) as follows:

~~C.15 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.~~

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

Comment 2:

The commentator further highlighted that condition C.16 (a) states "…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." In the matter of SDI, five years have past and no action has been taken. According to commentator, he doesn't have any faith in this.

Response 2:

The commentator is incorrect in stating the IDEM took no action against SDI and five years have past. The IDEM took enforcement action against SDI after non-compliant stack tests in 1996. The agreed order is available on our web site, case number 2759. The IDEM has aggressively pursued enforcement cases for violations in the past, and will continue to do so in the future. More details on enforcement actions taken by IDEM can be obtained from our web site at: http://www.IN.gov/idem/oe/index.html. The IDEM will pursue enforcement matters to maintain and improve the quality of environment in the State of Indiana and uphold the applicable regulations.

Comment 3:

The commentator discussed in detail that the formaldehyde emissions as documented in the vendor specification for Westinghouse 501 F's are stringent and there is a real chance that the plant will not meet that tough emission standard and will require their permit to be modified at a later date.

Response 3:

These issues have been discussed in detail while discussing the written comments from the same commentator in this TSD addendum previously. Of interest is the Response 3 in the written comment section above which details that the formaldehyde limit for the Westinghouse 501 F turbines has been revised to emission factor documented by Sims Roy of US EPA in his August 21, 2001 memo with 95 percentile confidence.

Comment 4:

Further, the commentator described the Rios letter (a letter addressed to Mr.David Dixon of San Luis Obispo Air Pollution Control District from Gerardo Rios of US EPA, Region IX), which discusses the NOx, CO and ammonia emission levels for combined cycle power plant.

Response 4:

The OAQ, IDEM, has discussed in detail why the limits proposed by Gerardo Rios is not as stringent as those proposed by IDEM in this permit. This discussion is available in the Response 10 of written comments in this TSD addendum.

Comment 5:

The commentator again stated his concern about high CO emission limit for the simple cycle GE LM 6000 aero derivative peaking turbines proposed in this project.

Response 5:

The OAQ, IDEM has addressed this comment in the Response 9 of written comment section above of this TSD addendum.

Comment 6:

Further Mr.Loeschner questioned how a one time stack test can show an hour by hour compliance with the permit limits.

Response 6:

All turbine projects permitted in the State of Indiana in recent past are required to perform formaldehyde emission stack test. The OAQ, IDEM will look into developing surrogate mechanisms to monitor formaldehyde emissions. While operating properly in the worst case (part load condition) scenario, if the stack test at a turbine demonstrate compliance with the formaldehyde emission limit and the Permittee maintains NOx and CO emissions with in the permit limits, there is every reason to believe that there will not be any major deviations in the formaldehyde emissions thereafter. Acadia Bay permit requires the turbines to have continuous emission monitoring systems for NOx and CO emissions. These emissions are direct indicators of the turbine performance. So with good combustion practices, as long as the NOx and CO emissions are controlled below the permit limit the formaldehyde emissions are expected to be in compliance with the permit limit.

Comment 7:

The commentator further questioned was there any other forms of verification of formaldehyde emissions. The commentator cited Whiting project, which has begun commercial operation by July 22nd this year. They are required to stack test within 180 days of this date. It is commentator's understanding that the company did some kind of preliminary testing and were not happy with the results. Now they are proposing to stack test by mid January.

Response 7:

The public hearing and this addendum to the TSD are for the proposed Acadia Bay permit only.

Even though not specifically related to the Acadia Bay permit, in response to this comment, Whiting Clean Energy has made a representation to the IDEM, that due to some unexpected, major operational difficulties (including main steam pipe rupture and leak) their production has been temporarily stopped. They are presently in the process of conducting a detailed investigation and will get back to IDEM with the dates for revised schedule for stack tests.

Comment 8:

Further the commentator stated "The law is rather clear, it says thou shalt not pass ten tons per year and it will be interesting to see when their test results come back that it will be possible that they have emitted their limit already. In other words in the first six months of testing, you don't know how much stuff came out and blew away, and yet the federal law says it shall be less than ten. And so this is not any form of confidence when there is no number there. They should be required to aggregate that from day one, and unless you have a continuous emission monitor for that there is no aggregation of that. The same way with the continuous emission monitors there is a delay of the time that they have to certify that as well. So you have a case where the emissions unit is operating and emitting, but yet you don't know what it put out because nobody was there measuring it. So you know I think that we've reached an impasse there and that is not an enforceable type thing. Six months goes by and no test, and then oh by the way, you run the test and get an unsatisfactory answer, well, what do you do then?"

Response 8:

Uncertainties of HAP emissions have been discussed in detail in Response 2, 3, 4 of the written comment section of the TSD addendum.

There is a six month shakedown period allowed both in federal and state regulations for any new operation to come on-line and achieve a sustainable performance. This applies to both the emission units and CEMs. The OAQ, IDEM has reasonable information to believe that the HAPs emissions from the combustion turbine will be below 10 tons per year threshold as explained in Response 2, 3 and 4 in written comments section.

As noted in the 2001 Sims Roy memo and the Response to Comment 12, the NOx emission levels are considered to be an indicator of proper lean premix combustor performance, which in turn should assure proper operation and low HAP emissions. The NOx and CO CEMS are subject to annual certification.

OAQ has the authority to request stack testing whenever it is determined to be necessary to demonstrate compliance with an applicable requirement. One possible scenario is when the quarterly NOx and CO reports indicated that a unit is not operating properly, OAQ could request additional formaldehyde testing to confirm the compliance status of the unit. The EPA Clean Air Markets Division does not recommend CEMS for formaldehyde.

Comment 9:

The commentator stated that a stack test after 100 days of commercial operation was found in non-compliance of the limit. With the penalty of $25,000 per day, for these violations, the company would conceivably be looking at two-and-a-half million dollars in fines, I don't think that any industry reasonably believes that they have anywhere near that level of threat hanging over their head.

Response 9:

The commentator seems to be suggesting that the IDEM should penalize all violations at the rate of $25,000 per day, but fails to do so. Pursuant to IC 13-30-4-1, the maximum civil penalty the IDEM may assess for any violation is $25,000 per day of violation. Most of the civil penalties assessed are likely to be less than that $25,000 per day, because most violations do not rise to a level of severity justifying assessing the maximum penalty.

Steve Hora

Comment 1:

The commentator stated on behalf of the town board of New Carlisle and local residents he welcomes the Acadia Bay project in their town. He went in detail about how the town favors this project. He requested that the permit be issued to this source.

Appendix A: Emissions Calculations
Summary of Emissions

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **25-Apr-01**

PTE										
Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	SC Turbine (tons/year)	SC Turbine SU/SD (tons/year)	Auxiliary Boiler (tons/year)		Cooling Tower (tons/year)	Emergency Generator (tons/year)		Total (tons/year)
NOx	858.43	76.013	360.57	18.00	4.51		-	54.58		1372.10
CO	345.82	264.83	300.48	14.60	7.54		-	11.76		945.03
VOC	49.06	N/A	70.08	N/A	0.50		-	4.43		124.06
SO2	49.06	N/A	12.26	N/A	0.05		-	3.61		64.98
PM/PM10	202.36	N/A	23.65	N/A	0.69		2.151	3.87		232.72
Formaldehyde	3.26	N/A	3.85	N/A	0.16		-	-		7.27
Combined HAP	8.36	N/A	5.58	N/A	0.17		-	-		14.11

Limited PTE										
Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	SC Turbine (tons/year)	SC Turbine SU/SD (tons/year)	Auxiliary Boiler (tons/year)		Cooling Tower (tons/year)	Emergency Generator (tons/year)		Total (tons/year)
NOx	142.91	76.013	139.65	18.00	4.51		-	3.12		384.20
CO	345.82	264.83	116.38	14.60	7.54		-	0.67		749.84
VOC	49.06	N/A	28.00	N/A	0.50		-	0.25		77.81
SO2	49.06	N/A	4.90	N/A	0.05		-	0.21		54.22
PM/PM10	202.36	N/A	9.45	N/A	0.69		2.151	0.22		214.87
Formaldehyde	3.26	N/A	1.54	N/A	0.16		-	-		4.96
Combined HAP	8.36	N/A	2.14	N/A	0.17		-	-		10.67

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Combined Cycle - Westinghouse 501 F Machines
Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 60 F **1843.00** MMBtu/hr Number of Turbines **2**

	Normal Operation	Startup/Shutdown
Turbine Operation (hrs/yr)	8176	585

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1843 MMBtu/hr	0.0570 lb/MMBtu	105.00	429.21 tons/yr	858.43 tons/yr
CO	1843 MMBtu/hr	0.0230 lb/MMBtu	42.30	172.91 tons/yr	345.82 tons/yr
VOC	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
SO_2	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
PM_{10}	1843 MMBtu/hr	0.0125 lb/MMBtu	23.10	101.18 tons/yr	202.36 tons/yr

Combustion turbine emission factors are vendor provide data
Calculations are based on 8760-SU/SD hours per year of operation (Normal Opeartion + Startup/Shutdown = 8760 hrs/yr)

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

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Combined Cycle - Westinghouse 501 F Machines
Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1843 MMBtu/hr	0.0095 lb/MMBtu*	17.48	71.46 tons/yr	142.91 tons/yr
CO	1843 MMBtu/hr	0.0230 lb/MMBtu	42.30	172.91 tons/yr	345.82 tons/yr
VOC	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
SO_2	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
PM_{10}	1843 MMBtu/hr	0.0125 lb/MMBtu	23.10	101.18 tons/yr	202.36 tons/yr

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

*CO emission factor for combustion turbine is based on 10.0 ppm

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: Acadia Bay Energy Co. LLC
Address City IN Zip: Corner of Walnut and Edison, New Carlisle, IN
CP: 141-14198
Plt ID: 141-00543
Reviewer: GS
Date: April 25, 2001

Startup/Shutdown Emissions

Combined Cycle Operation

	Hot	Warm	Cold
Estimated max startups per year	70	70	70
Startup duration (hours)	1.35	2.27	3.86
Total startup hours in a year			524
Estimated max shutdowns per year	70	70	70
Shutdown duration (hours)	0.29	0.29	0.29
Total shutdown hours in a year			61

Emissions from Combined Cycle Opeartion						
Pollutant	Type	Duration (hours)	Startup Emission Rate (lb/Startup)	Shutdown Emission Rate (lb/shutdown)	Emission Rate/Turbine (tons/yr)	Total Emission Rate based on all turbines (tons/yr)
NO_X	Hot	1.35	171.0	41.3	7.43	14.86
	Warm	2.27	294.0	41.3	11.74	23.47
	Cold	3.86	497.0	41.3	18.84	37.68
Total NOx per year					38.0	76.0
CO	Hot	1.35	613.0	431.0	21.47	42.93
	Warm	2.27	774.0	431.0	42.18	84.35
	Cold	3.86	1534.0	431.0	68.78	137.55
Total CO per year					132.42	264.83

*Emission rate/Turbine (tpy) includes both the startup and shutdown
Emission rates provided by the vendor

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

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Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Combustion Turbine Potential to Emit Calculations for HAPs

	Combustion Turbine			
HAPs	Emission Factor* (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr/unit)	Total PTE (8760 hrs/yr)
Acetaldehyde	4.00E-05	7.37E-02	3.23E-01	6.46E-01
Acrolein	6.40E-06	1.18E-02	5.17E-02	1.03E-01
Benzene	1.20E-05	2.21E-02	9.69E-02	1.94E-01
1,3 Butadiene**	4.30E-07	7.92E-04	3.47E-03	6.94E-03
Ethylbenzene	3.20E-05	5.90E-02	2.58E-01	5.17E-01
Formaldehyde!	2.02E-04	3.72E-01	1.63E+00	3.26E+00
PAHs	2.20E-06	4.05E-03	1.78E-02	3.55E-02
Propolene Oxide**	2.90E-05	5.34E-02	2.34E-01	4.68E-01
Toluene	1.30E-04	2.40E-01	1.05E+00	2.10E+00
Xylene	6.40E-05	1.18E-01	5.17E-01	1.03E+00
	single HAP			3.26
	combined HAP			8.36
Napthalene***	1.30E-06	2.40E-03	1.05E-02	2.10E-02

Methodology

* Emission Factors from AP-42, Section 3.1 Table 3.1-3, as updated 4/00
** Compound was not detected. The presented emission value is based on one-half of the detection limit.
*** Speciated PAH not included in HAPs table to avoid double counting of emissions.

Appendix A: Emissions Calculations
Simple Cycle Combustion Turbine LM 6000
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

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

Combustion Turbine Heat input @ 60 F **400.00** MMBtu/hr Number of Turbines **2**

	Normal Operation	Startup/Shutdown
Hours per year of Operation	**3500**	**175**

Combustion Turbine				
Pollutant	lb/MMBtu	lb/hr	PTE/CT	Total PTE
NO_X	0.105	42.00	180.29 tons/yr	360.57 tons/yr
CO	0.0875	35.00	150.24 tons/yr	300.48 tons/yr
VOC	0.02	8.00	35.04 tons/yr	70.08 tons/yr
SO_2	0.0035	1.40	6.13 tons/yr	12.26 tons/yr
PM_{10}	0.00675	2.70	11.83 tons/yr	23.65 tons/yr

Vendor estimates are used for NOx, CO, VOC
AP-42 emission factors are used for SO2 and PM10

Calculations are based on 8760 hours per year of operation

Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits and Limited hours of operation

Combustion Turbine				
Pollutant	lb/MMBtu	lb/hr	PTE/CT	Total PTE
NOx	0.105	42.00	69.83 tons/yr	139.65 tons/yr
CO	0.0875	35.00	58.19 tons/yr	116.38 tons/yr
VOC	0.02	8.00	14.00 tons/yr	28.00 tons/yr
SO_2	0.0035	1.40	2.45 tons/yr	4.90 tons/yr
PM_{10}	0.00675	2.70	4.73 tons/yr	9.45 tons/yr

Appendix A: Emissions Calculations
Simple Cycle Combustion Turbine LM 6000
Natural Gas Fired

Company Name:	**Acadia Bay Energy Co. LLC**
Address City IN Zip:	**Corner of Walnut and Edison, New Carlisle, IN**
CP:	**141-14198**
Plt ID:	**141-00543**
Reviewer:	**GS**
Date:	**April 25, 2001**

Startup/Shutdown Emissions

Simple Cycle Operation

Estimated max hours of startup per year	125
Estimated max hours of shutdown per year	50
Event consists of one startup and one shutdown	
No.of Events in a year	500

Emissions from Simple Cycle Operation			
Pollutant	Startup Emission Rate (lb/event)	Emission Rate/Turbine* (tons/yr)	Total Emission Rate (tons/yr)
NO_X	36	9.00	18.00
CO	29.2	7.30	14.60

Emission rates are as provided by the vendor

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

Appendix A: Emissions Calculations
Simple Cycle Combustion Turbine LM6000
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Combustion Turbine Potential to Emit Calculations for HAPs

	Combustion Turbine				
HAPs	Emission Factor* (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr/unit)	Total PTE (8760 hrs/yr)	Limited Total PTE (tpy)
Acetaldehyde	4.00E-05	1.60E-02	7.01E-02	1.40E-01	0.056
Acrolein	6.40E-06	2.56E-03	1.12E-02	2.24E-02	0.009
Benzene	1.20E-05	4.80E-03	2.10E-02	4.20E-02	0.017
1,3 Butadiene**	4.30E-07	1.72E-04	7.53E-04	1.51E-03	0.001
Ethylbenzene	3.20E-05	1.28E-02	5.61E-02	1.12E-01	0.045
Formaldehyde!	1.10E-03	4.40E-01	1.93E+00	3.85E+00	1.540
PAHs	1.80E-04	7.20E-02	3.15E-01	6.31E-01	0.252
Propolene Oxide**	2.90E-05	1.16E-02	5.08E-02	1.02E-01	0.041
Toluene	1.30E-04	5.20E-02	2.28E-01	4.56E-01	0.182
Xylene	6.40E-05	2.56E-02	1.12E-01	2.24E-01	0.090
	single HAP			3.85	1.54
	combined HAP			5.58	2.14

Napthalene***	1.30E-06	5.20E-04	2.28E-03	4.56E-03

Methodology

* Emission Factors from AP-42, Section 3.1 Table 3.1-3, as updated 4/00

** Compound was not detected. The presented emission value is based on one-half of the detection limit.

*** Speciated PAH not included in HAPs table to avoid double counting of emissions.

! Formaldehyde emissions based on compliance test at Allegheny Power Facility (Where)

Potential Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/ 2,000 lbs

Appendix A: Emissions Calculations
Auxillary Boiler Emissions
MM BTU/HR <100
Small Industrial Boiler

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Natural Gas Utility Boiler Calculation

Auxiliary Boiler Heat Input Rate 21 MMBtu/hr   Number of Boilers 1

Boiler Operation (hrs/yr) 8760

Auxiliary Boiler									
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE		PTE after Control or Enforcable Limits	
NO_X	21	MMBtu/hr	4.90E-02	lb/MMBtu	1.029	4.507	ton/yr	4.507	ton/yr
CO	21	MMBtu/hr	8.20E-02	lb/MMBtu	1.722	7.542	ton/yr	7.542	ton/yr
VOC	21	MMBtu/hr	5.40E-03	lb/MMBtu	0.113	0.497	ton/yr	0.497	ton/yr
SO_2	21	MMBtu/hr	5.88E-04	lb/MMBtu	0.012	0.054	ton/yr	0.054	ton/yr
PM_{10}	21	MMBtu/hr	7.50E-03	lb/MMBtu	0.158	0.690	ton/yr	0.690	ton/yr

*Emission factors are from AP-42 Table 1.4-2 utilizing Low NOx Burners
*Emission factors are based on a heating value of natural gas of 1050 Btu/scf

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	4.20E-05	1.84E-04	1.84E-04
Diclorobenzene	1.20E-03	1.14E-06	2.40E-05	1.05E-04	1.05E-04
Formaldehyde	7.50E-02	7.14E-05	1.50E-03	6.57E-03	6.57E-03
Hexane	1.80E+00	1.71E-03	3.60E-02	1.58E-01	1.58E-01
Napthalene	6.10E-04	5.81E-07	1.22E-05	5.34E-05	5.34E-05
Toluene	3.40E-03	3.24E-06	6.80E-05	2.98E-04	2.98E-04
POM	8.87E-05	8.45E-08	1.77E-06	7.77E-06	7.77E-06
Arsenic	2.00E-04	1.90E-07	4.00E-06	1.75E-05	1.75E-05
Beryllium	1.20E-05	1.14E-08	2.40E-07	1.05E-06	1.05E-06
Cadmium	1.10E-03	1.05E-06	2.20E-05	9.64E-05	9.64E-05
Chromium	1.40E-03	1.33E-06	2.80E-05	1.23E-04	1.23E-04
Cobalt	8.40E-05	8.00E-08	1.68E-06	7.36E-06	7.36E-06
Manganese	3.80E-04	3.62E-07	7.60E-06	3.33E-05	3.33E-05
Mercury	2.60E-04	2.48E-07	5.20E-06	2.28E-05	2.28E-05
Nickel	2.10E-03	2.00E-06	4.20E-05	1.84E-04	1.84E-04
Selenium	2.40E-05	2.29E-08	4.80E-07	2.10E-06	2.10E-06
		Single HAP		**1.58E-01**	**1.58E-01**
		Combined HAP		**1.65E-01**	**1.65E-01**

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

Appendix A: Emissions Calculations
Cooling Tower Emissions

Company Name:	**Acadia Bay Energy Co. LLC**
Address City IN Zip:	**Corner of Walnut and Edison, New Carlisle, IN**
CP:	**141-14198**
Plt ID:	**141-00543**
Reviewer:	**GS**
Date:	**April 25, 2001**

Cooling Tower Emissions

	Value	Unit	Calculation
Flow of Water at 100% Load	138232	gpm	vendor information
Cooling Water Flowrate	69171292.8	lb/hr	Flowrate (gal/min) * 8.34 lb/gal * 60 min/hr
Total Disolved Solids (TDS)	1420	ppm	vendor information
Cooling Water TDS Fraction	0.00142	lb TDS/lb	TDS/10^6 lb/ppm
Drift Loses (% of cooling water)	0.0005	%	vendor information
Liquid Drift Losses	345.856	lb/hr	Cooling water flow rate lb/hr * 0.001/100
Solids Drift Losses	0.491	lb/hr	Liquid Drift Losses * TDS Fraction lb TDS/lb
PM_{10}/TSD Emission	2.151	ton/yr	

Appendix A: Emissions Calculations
Backup Emergency Generators

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at 500 Limited hour per year hp-hr/yr
402	3521520	201000

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	3.87	3.87	3.61	54.58	4.43	11.76
Limited Potential Emission in tons/yr	0.22	0.22	0.21	3.12	0.25	0.67

Fuel Limit per Generator = 14210 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Indiana Department of Environmental Management
Office of Air Quality
and St. Joseph County Health Department

Technical Support Document (TSD) for a New Source Construction and Prevention of Significant Deterioration Permit

Source Background and Description

Source Name: **Acadia Bay Energy Co., LLC**
Source Location: **Walnut and Edison, New Carlisle, Indiana**
County: **St. Joseph**
Construction Permit: **141-14198-00543**
SIC Code: **4911**
Permit Reviewer: **Gurinder Saini**

The Office of Air Quality (OAQ) has received an application on March 22, 2001, from Acadia Bay Energy Co. LLC relating to the construction and operation of the St. Joseph County Generating facility near the town of New Carlisle. The proposed plant will be a 630 megawatt (MW) electric generating station. The permit restricts the combustion turbine generators to be fired using natural gas only. Any addition of backup fuel(s) in the future will require a modification to this permit and, if applicable, go through Prevention of Significant Deterioration (PSD) review. The source will consist of the following equipment:

Combined Cycle

(a) Two (2) natural gas-fired combined cycle combustion turbine generators designated as units CTG-01 and CTG-02, with a maximum heat input capacity of 1,867 MMBtu/hr (per unit on a lower heating value), and exhausting to stacks designated as S1 and S2, respectively.

(b) Two (2) heat recovery steam generators, designated as units HRSG1 and HRSG2.

(c) Two (2) selective catalytic reduction systems.

(d) One (1) cooling tower, consisting of 9 cells designated as Cool1 and exhausts to stack designated as S5 (A)-(I).

(e) One (1) auxiliary boiler, designated as unit Aux06 with maximum heat input rating of 21 MMBtu/hr, and exhausts to stack designated as S6.

(f) One (1) condensing steam turbine generator with an electric generating capacity of 178 MW at baseload design conditions.

Simple Cycle

(g) Two (2) natural gas-fired simple cycle combustion turbine generators designated as units CTG-03 and CTG-04 with a maximum heat input capacity of 423 MMBtu/hour (per unit on a lower heating value), and exhausting to stacks designated as S3 and S4, respectively.

(h) One (1) emergency diesel generator utilizing low sulfur diesel fuel, with a maximum capacity of 300 KW and exhausts to stack designated as S7.

Existing Approvals

This is the first air approval for this source.

Enforcement Issue

There are no enforcement actions pending.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^0F)
S1	Combined Cycle Combustion Turbine CTG-01	170	18	1,034,000	197
S2	Combined Cycle Combustion Turbine CTG-02	170	18	1,034,000	197
S3	Simple Cycle Combustion Turbine CTG-03	60	10	563,000	820
S4	Simple Cycle Combustion Turbine CTG-04	60	10	563,000	820
S5(A)-(I)	Cooling Towers (9 cells)	45	28	1,083,000 (per cell)	81
S6	Auxiliary Boiler	65	2	6,755	418
S7	Emergency Diesel Generator	30	0.5	-	500

Recommendation

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

Unless otherwise stated, information 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 March 22, 2001, with additional information received on May 8, 2001.

Emission Calculations

See Appendix (Emission Calculation Spreadsheets for detailed calculations). Criteria pollutant emission rates from the turbines are based on 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. It should also be noted that the emission factors, heat input and heat content values are based on the lower heating value (LHV).

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.

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

Potential To Emit of Source Before Controls and Enforceable Limits

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

Pollutant	Potential To Emit (tons/year)
PM	232
PM-10	232
SO_2	65
VOC	124
CO	945
NO_x	1372

HAP=s	Potential To Emit (tons/year)
Single HAP (Hexane)	4.22
Combination of HAPs	14.77

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM, PM-10, SO_2, VOC, CO and NOx are greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(b) Fugitive Emissions
Since this type of operation is one of the twenty-eight (28) listed source categories under 326 IAC 2-2, the fugitive particulate matter (PM) and volatile organic compound (VOC) emissions are counted toward determination of PSD applicability.

County Attainment Status

The source is located in St. Joseph County.

Pollutant	Status
PM-10	Attainment
SO_2	Attainment
NO_2	Attainment
Ozone	Maintenance
CO	Attainment
Lead	Attainment

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

(b) St. Joseph 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	215
PM10	215
SO_2	54
VOC	78
CO	749
NO_x	412

(a) This new source is a major stationary source because at least one regulated attainment pollutant is emitted at a rate of 100 tons per year or greater and is one of the 28 listed source categories. Therefore, pursuant to 326 IAC 2-2, and 40 CFR 52.21, the PSD requirements apply.

(b) The NO_X emissions from the combined cycle combustion turbines will be controlled by a selective catalytic reduction (SCR) system. Additionally NO_X emissions from the combined cycle combustion turbines will be controlled by dry low-NO_X combustors. The simple cycle combustion turbines will have limited hours of operation. The potential to emit in the table above is the PTE after NO_X control, and hours of operation limitations.

(c) 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 Source 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 this source becomes operational.

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

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

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

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

Federal Rule Applicability

40 CFR 60, Subpart GG (Stationary Gas Turbines)

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

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

(1) Limit nitrogen oxides emissions 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).

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

The owner, operator, or fuel vendor may develop a custom fuel schedule for determination of the nitrogen and sulfur content based on the design and operation of the affected Source and the characteristics of the fuel supply. These custom fuel schedules shall be approved by the Administrator before they can be used to comply with the above requirements.

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

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

According to 40 CFR 60.40a(b) (Applicability), this NSPS applies to fossil fuel fired in the steam generation. As the combined cycle turbine do not have any duct burners, NSPS is not applicable to this unit.

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 this NSPS is applicable to any steam generating units that has a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The proposed auxiliary boiler has a maximum rated heat input capacity of 21 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 Quality
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 2-2 (Prevention of Significant Deterioration)

This new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X because the potential to emit for these pollutants 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 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:

Two (2) combined cycle Westinghouse 501 F combustion turbines

Pollutant	Combustion Turbine	Limit (ppmvd @ 15% O_2)	Event (one Startup and one Shutdown)	Limit per power block (lb/event)
NO_X	Dry Low-NOx Combustors and SCR	3.0 (3 hour block avg.)	Limited to 4.16 hours per event per power block	1078
CO	Good Combustor Design and Combustion Control / CO Oxidation Catalyst	6.0 (24 hour block avg.)	Same as above	3935
VOC	Good Combustion Control	0.0034 lb/MMBtu	N/A	N/A
SO_2	Natural Gas as Sole Fuel	0.0034 lb/MMBtu	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.012 lb/MMBtu	N/A	N/A
Opacity	Natural Gas as Sole Fuel and Good Combustion Practice	20%	N/A	N/A

Two (2) simple cycle GE LM 6000 Sprint combustion turbines

Pollutant	Combustion Turbine	Limit (ppmvd @ 15% O_2)		Event (one Startup and one Shutdown)	Limit per combustion turbine (lb/event)
NO_X	Water Injection	25.0 (24 hour block avg.)		Limited to 0.35 hours per event per combustion turbine	36
CO	Good Combustion	Ambient temperature range	CO emissions concentration in ppmvd at 15% O_2 (24 hour block avg.)	Same as above	29.2
		Greater than 70°F	25		
		From 30°F to 70°F	50		
		From 0°F to 30°F	75		
		Less than 0°F	100		
VOC	Good Combustion Control	0.02 lb/MMBtu		N/A	N/A
SO_2	Natural Gas as Sole Fuel	0.0035 lb/MMBtu		N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.00675 lb/MMBtu		N/A	N/A
Opacity	Natural Gas as Sole Fuel and Good Combustion Practice	20%		N/A	N/A

Auxiliary Boiler

Pollutant	Auxiliary Boiler	Limit (lb/MMBtu)
NO_X	Natural Gas as Sole Fuel and Low NOx Combustors	0.049
CO	Good Combustion Practice	0.082
VOC	Good Combustion Practice	0.0054
SO_2	Natural Gas as Sole Fuel	0.0006
PM/PM_{10}	Natural Gas as Sole Fuel and Good Combustion Practice	0.0075
Opacity	Good Combustion Practice	20%

Cooling Towers

Pollutant	Control	Limit
NO_X	N/A	N/A
CO	N/A	N/A
VOC	N/A	N/A
SO_2	N/A	N/A
PM/PM_{10}	Drift Eliminators	0.49 lb/hour

326 IAC 2-4.1-1 (Major Source of Hazardous Air Pollutants)

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 is listed in the OAQ Construction Permit Application, Form Y (set forth 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 any single HAP emission is not greater than or equal to 10 tons per year and any combination HAP emissions are not greater than or equal to 25 tons per year.

326 IAC 2-6 (Emission Reporting)

The proposed Source 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 of NO_X and CO. Pursuant to this rule, the owner/operator of this Source must annually submit an emission statement of the Source. The annual statement must be received by April 15 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 Source is subject to 326 IAC 3-5 (Continuous Monitoring of Emissions) because the permit for this source contains an emission limit or standard established under the provisions of 326 IAC 2-2 (Prevention of Significant Deterioration) as defined by 326 IAC 3-5-1(d)(1).

(a) Pursuant to 326 IAC 3-5-1(c)(2)(A)(i) 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(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 parts per million (ppmvd) at 15% O_2. The use of CEMS to measure and record the NO_X and CO concentrations, 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) hour block for combined cycle combustion turbines and twenty four (24) hour for simple cycle combustion turbines. 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, using Method 19.

(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)

This source is not located in are north of Kern Road and East of Pine Road. Therefore this source is not subject to requirements of 326 IAC 5-1-2 (2). Therefore, pursuant to 326 IAC 5-1-2 (Opacity Limitations) except as provided in 326 IAC 5-1-3 (Temporary Exemptions), the opacity shall meet the following:

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

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

326 IAC 6-1 (Non-attainment area Particulate Emissions Limitations)

The proposed electric generation plant is subject to 326 IAC 6-1 (Nonattainment Area Particulate Limitations) because the proposed Source is located in St. Joseph County, listed in 326 IAC 6-1-7, and has the potential to emit 100 tons or more of particulate matter per year.

The proposed combustion turbines are subject to the general requirements (326 IAC 6-1-2(a)) which limit the particulate matter emissions to no more than 0.03 grains per dry standard cubic feet (dscf).

Qs = 60 x Vs x As

Qs std = 17.647 x Qs x (Ps/Ts) x (1-B ws)

Grains/dscf = (M x 7000) / (Qs std x 60)

Therefore:

Qs = (60) x (66) x (254) = 1.01 MMacfm

Qs std = (17.647) x (1.01E06) x (29.92/657) x (1-0.0775) = 746,000 dscfm

Grains/dscf = (24.8 x 7000) / (746,000 x 60) = 0.0039 grains/dscf

Where:

Qs = Volumetric flow rate - actual cubic feet per minute
Qs std = Volumetric flow rate - dry standard cubic feet per minute
Vs = Velocity through stack = 66 ft/s
As = Area of stack opening = 254 ft^2
Ps = Stack Pressure = ~29.92 in hg
Ts = Stack Temperature = 657 R
Bws = % moisture = ~7.75%
M = Flow = 24.8 lb/hr

Therefore, the PM emissions from the combustion turbines comply with this limit.

The proposed auxiliary boiler is subject to the requirements of 326 IAC 6-1-2(b)(1) which limit the particulate matter emissions to no more than 0.01 grains per dry standard cubic feet (dscf).

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 handling systems that could generate fugitive emissions and all of the roads and parking areas located at the proposed Source 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 8-1-6 (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 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 Reasonable Achievable Control Technology (RACT) for the proposed operation.

326 IAC 9 (Carbon Monoxide Emission Limits)

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

326 IAC 10 (Nitrogen Oxides)

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

Conclusion

The construction and operation of this combined cycle and simple cycle merchant power plant shall be subject to the conditions of the attached proposed New Source Construction and Prevention of Significant Deterioration Permit 141-14198-00543.

Appendix A: Emissions Calculations
Summary of Emissions

Company Name: Acadia Bay Energy Co. LLC
Address City IN Zip: Corner of Walnut and Edison, New Carlisle, IN
CP: 141-14198
Plt ID: 141-00543
Reviewer: GS
Date: 25-Apr-01

PTE

Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	SC Turbine (tons/year)	SC Turbine SU/SD (tons/year)	Auxiliary Boiler (tons/year)		Cooling Tower (tons/year)	Emergency Generator (tons/year)		Total (tons/year)
NOx	858.43	76.013	360.57	18.00	4.51		-	54.58		1372.10
CO	345.82	264.83	300.48	14.60	7.54		-	11.76		945.03
VOC	49.06	N/A	70.08	N/A	0.50		-	4.43		124.06
SO2	49.06	N/A	12.26	N/A	0.05		-	3.61		64.98
PM/PM10	202.36	N/A	23.65	N/A	0.69		2.151	3.87		232.72
Formaldehyde	3.26	N/A	3.85	N/A	0.16		-	-		7.27
Combined HAP	8.36	N/A	5.58	N/A	0.17		-	-		14.11

Limited PTE

Pollutant	CC Turbine (tons/year)	CC Turbine SU/SD (tons/year)	SC Turbine (tons/year)	SC Turbine SU/SD (tons/year)	Auxiliary Boiler (tons/year)		Cooling Tower (tons/year)	Emergency Generator (tons/year)		Total (tons/year)
NOx	142.91	76.013	139.65	18.00	4.51		-	3.12		384.20
CO	345.82	264.83	116.38	14.60	7.54		-	0.67		749.84
VOC	49.06	N/A	28.00	N/A	0.50		-	0.25		77.81
SO2	49.06	N/A	4.90	N/A	0.05		-	0.21		54.22
PM/PM10	202.36	N/A	9.45	N/A	0.69		2.151	0.22		214.87
Formaldehyde	3.26	N/A	1.54	N/A	0.16		-	-		4.96
Combined HAP	8.36	N/A	2.14	N/A	0.17		-	-		10.67

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Combined Cycle - Westinghouse 501 F Machines
Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 60 F **1843.00** MMBtu/hr   Number of Turbines **2**

	Normal Operation	Startup/Shutdown
Turbine Operation (hrs/yr)	8176	585

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1843 MMBtu/hr	0.0570 lb/MMBtu	105.00	429.21 tons/yr	858.43 tons/yr
CO	1843 MMBtu/hr	0.0230 lb/MMBtu	42.30	172.91 tons/yr	345.82 tons/yr
VOC	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
SO_2	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
PM_{10}	1843 MMBtu/hr	0.0125 lb/MMBtu	23.10	101.18 tons/yr	202.36 tons/yr

Combustion turbine emission factors are vendor provide data
Calculations are based on 8760-SU/SD hours per year of operation (Normal Opeartion + Startup/Shutdown = 8760 hrs/yr)

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Combined Cycle - Westinghouse 501 F Machines
Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits

Combustion Turbine					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1843 MMBtu/hr	0.0095 lb/MMBtu*	17.48	71.46 tons/yr	142.91 tons/yr
CO	1843 MMBtu/hr	0.0230 lb/MMBtu	42.30	172.91 tons/yr	345.82 tons/yr
VOC	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
SO_2	1843 MMBtu/hr	0.0030 lb/MMBtu	5.60	24.53 tons/yr	49.06 tons/yr
PM_{10}	1843 MMBtu/hr	0.0125 lb/MMBtu	23.10	101.18 tons/yr	202.36 tons/yr

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

*CO emission factor for combustion turbine is based on 10.0 ppm

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: Acadia Bay Energy Co. LLC
Address City IN Zip: Corner of Walnut and Edison, New Carlisle, IN
CP: 141-14198
Plt ID: 141-00543
Reviewer: GS
Date: April 25, 2001

Startup/Shutdown Emissions

Combined Cycle Operation

	Hot	Warm	Cold
Estimated max startups per year	70	70	70
Startup duration (hours)	1.35	2.27	3.86
Total startup hours in a year			524
Estimated max shutdowns per year	70	70	70
Shutdown duration (hours)	0.29	0.29	0.29
Total shutdown hours in a year			61

Emissions from Combined Cycle Opeartion

Pollutant	Type	Duration (hours)	Startup Emission Rate (lb/Startup)	Shutdown Emission Rate (lb/shutdown)	Emission Rate/Turbine (tons/yr)	Total Emission Rate based on all turbines (tons/yr)
NO_X	Hot	1.35	171.0	41.3	7.43	14.86
	Warm	2.27	294.0	41.3	11.74	23.47
	Cold	3.86	497.0	41.3	18.84	37.68
Total NOx per year					38.0	76.0
CO	Hot	1.35	613.0	431.0	21.47	42.93
	Warm	2.27	774.0	431.0	42.18	84.35
	Cold	3.86	1534.0	431.0	68.78	137.55
Total CO per year					132.42	264.83

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

Emission rates provided by the vendor

Appendix A: Emissions Calculations
Combined Cycle Combustion Turbine
Natural Gas Fired

Company Name: Acadia Bay Energy Co. LLC
Address City IN Zip: Corner of Walnut and Edison, New Carlisle, IN
CP: 141-14198
Plt ID: 141-00543
Reviewer: GS
Date: April 25, 2001

Combustion Turbine Potential to Emit Calculations for HAPs

	Combustion Turbine			
HAPs	Emission Factor* (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr/unit)	Total PTE (8760 hrs/yr)
Acetaldehyde	4.00E-05	7.37E-02	3.23E-01	6.46E-01
Acrolein	6.40E-06	1.18E-02	5.17E-02	1.03E-01
Benzene	1.20E-05	2.21E-02	9.69E-02	1.94E-01
1,3 Butadiene**	4.30E-07	7.92E-04	3.47E-03	6.94E-03
Ethylbenzene	3.20E-05	5.90E-02	2.58E-01	5.17E-01
Formaldehyde!	2.02E-04	3.72E-01	1.63E+00	3.26E+00
PAHs	2.20E-06	4.05E-03	1.78E-02	3.55E-02
Propolene Oxide**	2.90E-05	5.34E-02	2.34E-01	4.68E-01
Toluene	1.30E-04	2.40E-01	1.05E+00	2.10E+00
Xylene	6.40E-05	1.18E-01	5.17E-01	1.03E+00
	single HAP			3.26
	combined HAP			8.36
Napthalene***	1.30E-06	2.40E-03	1.05E-02	2.10E-02

<u>Methodology</u>

* Emission Factors from AP-42, Section 3.1 Table 3.1-3, as updated 4/00
** Compound was not detected. The presented emission value is based on one-half of the detection limit.
*** Speciated PAH not included in HAPs table to avoid double counting of emissions.

Appendix A: Emissions Calculations
Simple Cycle Combustion Turbine LM 6000
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

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

Combustion Turbine Heat input @ 60 F **400.00** MMBtu/hr Number of Turbines **2**

	Normal Operation	Startup/Shutdown
Hours per year of Operation	**3500**	**175**

Combustion Turbine				
Pollutant	lb/MMBtu	lb/hr	PTE/CT	Total PTE
NO_X	0.105	42.00	180.29 tons/yr	360.57 tons/yr
CO	0.0875	35.00	150.24 tons/yr	300.48 tons/yr
VOC	0.02	8.00	35.04 tons/yr	70.08 tons/yr
SO_2	0.0035	1.40	6.13 tons/yr	12.26 tons/yr
PM_{10}	0.00675	2.70	11.83 tons/yr	23.65 tons/yr

Vendor estimates are used for NOx, CO, VOC
AP-42 emission factors are used for SO2 and PM10

Calculations are based on 8760 hours per year of operation

Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits and Limited hours of operation

Combustion Turbine				
Pollutant	lb/MMBtu	lb/hr	PTE/CT	Total PTE
NOx	0.105	42.00	69.83 tons/yr	139.65 tons/yr
CO	0.0875	35.00	58.19 tons/yr	116.38 tons/yr
VOC	0.02	8.00	14.00 tons/yr	28.00 tons/yr
SO_2	0.0035	1.40	2.45 tons/yr	4.90 tons/yr
PM_{10}	0.00675	2.70	4.73 tons/yr	9.45 tons/yr

Appendix A: Emissions Calculations
Simple Cycle Combustion Turbine LM 6000
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Startup/Shutdown Emissions

Simple Cycle Operation

Estimated max hours of startup per year	125
Estimated max hours of shutdown per year	50
Event consists of one startup and one shutdown	
No.of Events in a year	500

Emissions from Simple Cycle Operation			
Pollutant	Startup Emission Rate (lb/event)	Emission Rate/Turbine* (tons/yr)	Total Emission Rate (tons/yr)
NO_X	36	9.00	18.00
CO	29.2	7.30	14.60

Emission rates are as provided by the vendor
*Emission rate/Turbine (tpy) includes both the startup and shutdown

Appendix A: Emissions Calculations
Simple Cycle Combustion Turbine LM6000
Natural Gas Fired

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Combustion Turbine Potential to Emit Calculations for HAPs

	Combustion Turbine				
HAPs	Emission Factor* (lb/MMBtu)	Emission Rate (lb/hr)	PTE (8760 hrs/yr/unit)	Total PTE (8760 hrs/yr)	Limited Total PTE (tpy)
Acetaldehyde	4.00E-05	1.60E-02	7.01E-02	1.40E-01	0.056
Acrolein	6.40E-06	2.56E-03	1.12E-02	2.24E-02	0.009
Benzene	1.20E-05	4.80E-03	2.10E-02	4.20E-02	0.017
1,3 Butadiene**	4.30E-07	1.72E-04	7.53E-04	1.51E-03	0.001
Ethylbenzene	3.20E-05	1.28E-02	5.61E-02	1.12E-01	0.045
Formaldehyde!	1.10E-03	4.40E-01	1.93E+00	3.85E+00	1.540
PAHs	1.80E-04	7.20E-02	3.15E-01	6.31E-01	0.252
Propolene Oxide**	2.90E-05	1.16E-02	5.08E-02	1.02E-01	0.041
Toluene	1.30E-04	5.20E-02	2.28E-01	4.56E-01	0.182
Xylene	6.40E-05	2.56E-02	1.12E-01	2.24E-01	0.090
	single HAP			3.85	1.54
	combined HAP			5.58	2.14
Napthalene***	1.30E-06	5.20E-04	2.28E-03	4.56E-03	

<u>Methodology</u>

* Emission Factors from AP-42, Section 3.1 Table 3.1-3, as updated 4/00

** Compound was not detected. The presented emission value is based on one-half of the detection limit.

*** Speciated PAH not included in HAPs table to avoid double counting of emissions.

! Formaldehyde emissions based on compliance test at Allegheny Power Facility (Where)

Potential Emission (tons/yr) = Heat Input Capacity (MMBtu/hr) x Emission Factor (lb/MMBtu) x 8760 hrs/yr x 1 ton/ 2,000 lbs

Appendix A: Emissions Calculations
Auxillary Boiler Emissions
MM BTU/HR <100
Small Industrial Boiler

Company Name: Acadia Bay Energy Co. LLC
Address City IN Zip: Corner of Walnut and Edison, New Carlisle, IN
CP: 141-14198
Plt ID: 141-00543
Reviewer: GS
Date: April 25, 2001

Natural Gas Utility Boiler Calculation

Auxiliary Boiler Heat Input Rate: 21 MMBtu/hr

Number of Boilers: 1

Boiler Operation (hrs/yr): 8760

Auxiliary Boiler										
Pollutant	Heat Input		Emission Factor		lb/hr	Boiler PTE		PTE after Control or Enforcable Limits	
NO_X	21	MMBtu/hr	4.90E-02	lb/MMBtu	1.029	4.507	ton/yr	4.507	ton/yr
CO	21	MMBtu/hr	8.20E-02	lb/MMBtu	1.722	7.542	ton/yr	7.542	ton/yr
VOC	21	MMBtu/hr	5.40E-03	lb/MMBtu	0.113	0.497	ton/yr	0.497	ton/yr
SO_2	21	MMBtu/hr	5.88E-04	lb/MMBtu	0.012	0.054	ton/yr	0.054	ton/yr
PM_{10}	21	MMBtu/hr	7.50E-03	lb/MMBtu	0.158	0.690	ton/yr	0.690	ton/yr

*Emission factors are from AP-42 Table 1.4-2 utilizing Low NOx Burners
*Emission factors are based on a heating value of natural gas of 1050 Btu/scf

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	4.20E-05	1.84E-04	1.84E-04
Diclorobenzene	1.20E-03	1.14E-06	2.40E-05	1.05E-04	1.05E-04
Formaldehyde	7.50E-02	7.14E-05	1.50E-03	6.57E-03	6.57E-03
Hexane	1.80E+00	1.71E-03	3.60E-02	1.58E-01	1.58E-01
Napthalene	6.10E-04	5.81E-07	1.22E-05	5.34E-05	5.34E-05
Toluene	3.40E-03	3.24E-06	6.80E-05	2.98E-04	2.98E-04
POM	8.87E-05	8.45E-08	1.77E-06	7.77E-06	7.77E-06
Arsenic	2.00E-04	1.90E-07	4.00E-06	1.75E-05	1.75E-05
Beryllium	1.20E-05	1.14E-08	2.40E-07	1.05E-06	1.05E-06
Cadmium	1.10E-03	1.05E-06	2.20E-05	9.64E-05	9.64E-05
Chromium	1.40E-03	1.33E-06	2.80E-05	1.23E-04	1.23E-04
Cobalt	8.40E-05	8.00E-08	1.68E-06	7.36E-06	7.36E-06
Manganese	3.80E-04	3.62E-07	7.60E-06	3.33E-05	3.33E-05
Mercury	2.60E-04	2.48E-07	5.20E-06	2.28E-05	2.28E-05
Nickel	2.10E-03	2.00E-06	4.20E-05	1.84E-04	1.84E-04
Selenium	2.40E-05	2.29E-08	4.80E-07	2.10E-06	2.10E-06
		Single HAP		**1.58E-01**	**1.58E-01**
		Combined HAP		**1.65E-01**	**1.65E-01**

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

Appendix A: Emissions Calculations
Cooling Tower Emissions

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Cooling Tower Emissions

	Value	Unit	Calculation
Flow of Water at 100% Load	138232	gpm	vendor information
Cooling Water Flowrate	69171292.8	lb/hr	Flowrate (gal/min) * 8.34 lb/gal * 60 min/hr
Total Disolved Solids (TDS)	1420	ppm	vendor information
Cooling Water TDS Fraction	0.00142	lb TDS/lb	TDS/10^6 lb/ppm
Drift Loses (% of cooling water)	0.0005	%	vendor information
Liquid Drift Losses	345.856	lb/hr	Cooling water flow rate lb/hr * 0.001/100
Solids Drift Losses	0.491	lb/hr	Liquid Drift Losses * TDS Fraction lb TDS/lb
PM_{10}/TSD Emission	2.151	ton/yr	

Appendix A: Emissions Calculations
Backup Emergency Generators

Company Name: **Acadia Bay Energy Co. LLC**
Address City IN Zip: **Corner of Walnut and Edison, New Carlisle, IN**
CP: **141-14198**
Plt ID: **141-00543**
Reviewer: **GS**
Date: **April 25, 2001**

Heat Input Capacity Horsepower (hp)	Potential Throughput hp-hr/yr	Potential Throughput at hp-hr/yr	500 Limited hour per year
402	3521520	201000	

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/hp-hr	0.0022	0.0022	0.00205	0.031	0.0025141	0.00668
Potential Emission in tons/yr	3.87	3.87	3.61	54.58	4.43	11.76
Limited Potential Emission in tons/yr	0.22	0.22	0.21	3.12	0.25	0.67

Fuel Limit per Generator = 14210 gallons of diesel

Methodology

Potential Througput (hp-hr/yr) = hp * 8760 hr/yr
Use a conversion factor of 7,000 Btu per hp-hr to convert from horsepower to Btu/hr, unless the source gives you a source-specific brake-specific fuel consumption. (AP-42, Footnote a, Table 3.3-1)
Emission Factors are from AP42 (Supplement B 10/96), Table 3.3-2
Emission (tons/yr) = [Potential Throughput (hp-/hr/yr) x Emission Factor (lb/hp-hr)] / (2,000 lb/ton)

Appendix B - Air Quality Analysis

Source Name:	Acadia Bay Energy Co., LLC
Source Location:	Walnut and Edison, New Carlisle, Indiana
County:	St. Joseph
Construction Permit:	141-14198-00543
SIC Code:	4911

Introduction

Acadia Bay has applied to construct an electric generating facility south of New Carlisle in St. Joseph County, Indiana. The site is located at Universal Transverse Mercator (UTM) coordinates 543000 East and 4616000 North. St. Joseph County is designated as attainment for the National Ambient Air Quality Standards for all enforceable pollutants. These standards are set by U.S. EPA to protect the public health and welfare.

The air quality analysis for the air permit application was received by the Office of Air Quality (OAQ) in March of 2001. This document provides OAQ's Air Quality Modeling Section's review of the permit application including an air quality analysis performed by the OAQ.

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 the source's 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 and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is more than 100 kilometers from the proposed modification.

Summary

Acadia Bay has applied for a construction permit to modify their facility, near New Carlisle in St. Joseph County, Indiana. The air quality impact section of the application was prepared by URS Corp. St. Joseph County is currently designated as attainment for all enforceable criteria pollutants. The permit is PSD for Particulate Matter less than 10 microns (PM10), Nitrogen Oxides (NOx), Carbon Monoxide (CO) and Sulfur Dioxide (SO2). Modeling results taken from the Industrial Source Complex Short Term (ISCST3) model showed that for all pollutants were predicted to be less than the significant impact increments and significant monitoring de minimus levels. 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, because the project is greater than 100 kilometers away from Mammoth Cave National Park in Kentucky. An additional impact analysis on the surrounding area was conducted and showed no significant impact on economic growth, soils, vegetation, federal and state endangered species or visibility from the proposed facility.

Part A - Pollutants Analyzed for Air Quality Impact

Indiana Administrative Codes (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. Acadia Bay will emit CO, NO2, SO2, VOC (ozone) and PM_{10} in excess of their significant emission rates as shown in Table 1.

TABLE 1 - Acadia Bay's Emission Rates (tons/yr)*		
Pollutant	**Maximum Allowable Emissions**	**Significant Emission Rate**
CO	788	100
NO2	454	40
SO2	54	40
PM_{10}	215	15
VOC	78	40

* Including emissions from start up/shut down as well as emergency and backup equipment.

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 source 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.

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. Long-term (annual) worst-case determinations were based on the permit limits of operation per year using natural gas or diesel-firings. Stack parameters were based on peak-summer demand conditions.

Model Description

The Office of Air Quality review used the Industrial Source Complex Short Term (ISCST3) model, 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 "Guideline on Air Quality Models". The model also utilized the Schulman-Scire algorithm to account for building downwash effects. Stacks associated with the proposed modification are below the Good Engineering Practice (GEP) formula for stack heights. This indicates that wind flow over and around surrounding buildings can influence the dispersion of pollutant coming from the stacks. 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 surface data from the South Bend National Weather Service station merged with the mixing heights from Peoria, Illinois. National Weather Service Station for the five-year period (1990-1994). The 1990-1994 meteorological data was obtained through the National Oceanic and Atmospheric Administration (NOAA) and National Climatic Data Center (NCDC) and preprocessed into ISCST3 forma with an updated version of U.S. EPA's PCRAMMET program.

Modeled Results

Maximum modeled concentrations for each pollutant over its significant emission rate are listed below in Table 2 and are compared to each pollutant's significant impact increment for Class II areas, as specified by U.S. EPA.

The turbines were modeled under a variety of operating scenarios with the most recent year of meteorological data (1994) to determine the worst-case conditions for each averaging period for each pollutant. Then all of the equipment was modeled under those conditions for all five years with the results shown below.

TABLE 2 - Summary of OAQ's Significant Impact Analysis (ug/m3)

Pollutant	Year	Time-Averaging Period	Acadia Bay Maximum Modeled Impacts	Significant Impact Increments	Significant Monitoring Increments
PM10	1991	24-hour	4.1	**5**	10
PM10	1990	Annual	0.39	**1**	[a]
Sulfur Dioxide	1990	Annual	0.12	**1**	[a]
Sulfur Dioxide	1991	24-hour	1.8	**5**	13
Sulfur Dioxide	1993	3-hour	5.6	**25**	[a]
Nitrogen Dioxide[b]	1990	Annual	0.50	**1**	[a]
Carbon Monoxide	1991	8-hour	458.0	**500**	575
Carbon Monoxide	1990	1-hour	880.8	**2000**	2300

[a] No limit exists for this time-averaged period
[b] EPA's default Ambient Ratio Method (ARM) factor of 0.75 was applied to the NOx emission rates to obtain NO2 impacts

Concentrations for each pollutant at all applicable time-averaged periods were below both the significant impact increment and significant monitoring de minimus levels. 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.

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. The results of the wind rose analysis and the puff transport model show that any potential plume emitted from the facility would fall out to the north and east of the facility.

OAQ Multi-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 county-wide NOx and VOC emissions. Results from this analysis show Acadia Bay's turbines limited VOC emissions of 653 pounds/day would comprise 0.1% of the VOC emissions from point, area, onroad and nonroad mobile source and biogenic emissions. Results from this analysis show Acadia Bay's turbines limited NOx emissions of 3,019 pounds/day would comprise 0.7% of the area-wide NOx emissions from point, area, onroad and nonroad mobile source emissions.

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 are the monitors of South Bend, Indiana. The design value for the Children's Hospital monitor is 113 ppb for the 1-hour ozone standard. Ozone readings have trended upward about 15 ppb in the last 8 years.

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. Pollutant impacts from the Acadia Bay proposed facility would likely fall north, northeast and east northeast of the facility, and would likely impact the north edge of the South Bend region.

The final step in evaluating the ozone impacts from a single source is to estimate the source's individual impact through a screening procedure. The Reactive Plume Model-IV (RPM-IV) has been utilized in the past to attempt to determine 1-hour ozone impacts from single VOC/NOx source emissions. Modeling for 1 hour ozone concentrations was conducted for a typical high ozone day to compare the results to the ozone National Ambient Air Quality Standard (NAAQS) limit. OAQ modeling results assumed the short-term emission rates of NO_2 and VOCs and are shown in Table 3. The impact (difference between the plume-injected and ambient modes) from Acadia Bay was less than one ppb. All ambient plus plume-injected modes were below the NAAQS limit for ozone at every time period and every distance.

From this four-tiered approach, ozone formation is a regional issue and the emissions from Acadia Bay will represent a small fraction of VOC emissions in the area. Ozone contribution from Acadia Bay emissions is expected to be minimal. Ozone historical data shows that the area monitors have design values below the ozone NAAQS of 125 ppb and the Acadia Bay ozone impact based on the emissions and modeling will have minimal impact on ozone concentrations in the area.

Table 3 - RPM-IV Modeling for Acadia Bay				
NAAQS Analysis for Ozone (June 6, 1995)				
Time	**Distance**	**Ambient**	**Plume-Injected**	**Source Impact**
(hours)	(meters)	(ppb)	(ppb)	(ppb)
700.0	100	28	28	0
800.0	9352	53.3	53.5	0.3
900.0	20476	74.1	73.7	-0.4
1000.0	31600	91.2	90.8	-0.4
1100.0	40852	105	105	-0.3
1200.0	50104	113	113	-0.1
1300.0	59356	118	117	-1.3
1400.0	68608	120	118	-2.3
1500.0	77860	121	118	-2.9
1600.0	87112	121	118	-3.3

Part E - Hazardous Air Pollutant Analysis and Results

OAQ presently 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 and may be used by industries in the State of Indiana. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality's construction permit application Form Y. Any one HAP over 10 tons/year or all HAPs with total emissions over 25 tons/year will be subject to toxic modeling analysis. The modeled emissions for each HAP are the total emissions, based over 8760 hours per year. The resulting concentrations from the limited HAP emission are less than the total HAP emissions, based on permitted limits of operation over a year. For conservative purposes, the total emissions were modeled and the maximum concentrations were used.

OAQ performed HAP 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). In Table 4 below, the results of the HAP analysis with the emission rates, modeled concentrations and the percentages of the PEL for each HAP are listed. All HAPs concentrations were modeled below 0.5% of their respective PELs.

TABLE 4 - HAPS Analysis				
Hazardous Air Pollutants	**HAP Emissions**	**Maximum 8-hour concentrations**	**PEL**	**Percent of PEL**
	(Lb/hour)	(ug/m3)	(ug/m3)	(%)
Butadiene	0.002	0.00028	2200	0.000
Acetaldehyde	0.179	0.02620	360000	0.000
Benzene	0.054	0.00800	3200	0.000
Ethylbenzene	0.144	0.02100	435000	0.000
Formaldehyde	1.140	0.09300	930	0.010
Hexane	0.930	0.29300	1800000	0.016
Napthalene	0.006	0.04410	50000	0.000
Toluene	0.584	0.08280	750000	0.000
Xylene	0.287	0.04450	435000	0.000

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

Part F - 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. An analysis on economic growth, soils, vegetation and visibility and is listed below.

Economic Growth and Impact of Construction Analysis

Any commercial growth, as a result of the proposed modification, is not expected to occur. 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 St. Joseph County are predominately Plainfield Oshten sands with Maumee, Gilford sandy lOAQs, Tracy, Door and Fox lOAQs. The general landscape consists of Kankakee Outwash and Cacustrine plain. (1816 - 1966 Natural Features of Indiana - Indiana Academy of Science). According to the low modeled PM10 concentrations and the insignificant modeled concentrations NOx, SO2 and CO along with the HAPs analysis, the soils will not be adversely affected by the proposed modification.

Vegetation Analysis

Due to the agricultural nature of the land, vegetation in the St. Joseph County area consists mainly of crops such as corn, wheat, soybeans and hay. The maximum modeled concentrations of the proposed modification for NOx, SO2 and CO, and PM_{10} are well below the threshold limits necessary to have adverse impacts on surrounding vegetation (Flora of Indiana - Charles Deam). Federally endangered or threatened plants as listed in the U.S. Fish and Wildlife Service , Division of Endangered

Species for Indiana list no threatened or endangered species of plants or animals. Trees in the area are considered hardy trees and due to the insignificant 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 specie of snake. The state of Indiana's 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 of Acadia Bay's proposed facility. However, the project is not expected to have any adverse effects on the habitats of these species.

Additional Analysis Conclusions

The nearest Class I area to the proposed modification facility is the Mammoth Cave National Park located further than 100 km to the south in Kentucky. Therefore, no modeling was required to predict the impact of the facility on this Class I area.

The results of the additional impact analysis conclude the Acadia Bay's proposed modification facility will have no adverse impact on economic growth, soils, vegetation, endangered or threatened species or visibility on any Class I area.

Appendix C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) Review

Source Name:	Acadia Bay Energy Co., LLC
Source Location:	Walnut and Edison, New Carlisle, Indiana
County:	St. Joseph
Construction Permit No.:	141-14198-00543
SIC Code:	4911
Permit Reviewer:	Gurinder Saini

The Office of Air Quality (OAQ), Indiana Department of Environmental Management (IDEM), has carried out the following federal BACT review for the proposed electric generating plant to be owned and operated by Acadia Bay Energy Co., LLC (ABEC). This review was performed for two natural gas combined cycle combustion turbines, two simple cycle combustion turbines, one cooling tower and one auxiliary boiler.

The source is located in St. Joseph County, which is designated as attainment or unclassifiable for all criteria pollutants (VOC, NO_X, CO, PM, PM_{10}, $S0_2$ and Lead). Therefore, these pollutants were reviewed pursuant to the PSD Program (326 IAC 2-2 and 40 CFR 52.21). The PM, PM_{10}, CO, VOC, SO_2 and NO_x pollutants are subject to BACT review because the pollutant emissions are above PSD significant threshold levels set forth in 326 IAC 2-2. The BACT determination could be 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 Best Available Control Technology, with guidance set forth in USEPA 1990 draft *New Source Review Workshop Manuel*, the BACT analysis takes into account the energy, environment, and economic impacts on the source. These reductions may be determined through the application of available control techniques, process design, and/or operational limitations. These reductions are needed to demonstrate that the remaining emissions after BACT implementation will not cause or contribute to the significant air pollution thereby protecting the public health and the environment.

(A) Two Natural Gas-Fired Combined Cycle Combustion Turbines

The two combined cycle combustion turbines at the proposed ABEC Plant will be Westinghouse 501 F models equipped with dry low-NO_X combustion systems. The maximum heat input rating for each of the combustion turbines is 1867 MMBtu per hour.

(1) PM / PM10 BACT Review

There are three potential sources of filterable particulate emissions from combustion sources: minerals found in the fuel, solids or dust in the ambient air, which is used for combustion and unburned, carbon or soot formed by incomplete combustion of the fuel. The fuel for this proposed power generation plant, that is, natural gas is free of minerals. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to compression and used as combustion air in the combustion turbine. The potential for soot formation in a natural gas-fired combustion turbine is very low because the fuel is burnt under excess air combustion conditions. As a result, there are minimal filterable particulate emissions from the turbines.

There are two sources of the condensable particulate emissions from the combustion activity: condensable organic that are the result of incomplete combustion and sulfuric acid mist which is found as sulfuric acid dihydrate. For sources using natural gas fuel, such as the proposed power plant, there would be no condensable organic emitted because the main components of natural gas (i.e. methane and ethane) are not condensable at the temperature used in a Method 202 ice bath. As such, any condensed organic are from the ambient air. The most likely condensable 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 cools.

Additional consideration of particulate matter generated during combustion is the use of additional NO_X and CO add-on control. When using selective catalytic reduction (SCR) to control NO_X, PM/PM_{10} emissions increase due to the formation of ammonium nitrates and ammonium sulfates. Ammonia nitrate particles are formed when ammonia reacts with nitric acid, a derivative of NO_X emissions. Ammonia sulfate particles are formed when acid sulfate aerosols, formed during the oxidation of SO_2 emissions, react with excess ammonia. In addition the use of a catalytic oxidation system to control CO has the potential to increase PM/PM_{10}.

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

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Venturi Scrubber

Technically Infeasible Control Options – Traditional add on particulate control, such as the above listed, have not been applied to natural gas fired combustion turbines. The presence of high temperature regime, 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 PM in turbine exhausts.

Combined Cycle Combustion Turbines

Company	Facility	Throughput (MMBtu/hr)	Emission Rate (lb/MMBtu)	Control Description
Proposed ABEC Facility	Turbine	1867	0.012	Good Combustion
Proposed Duke Vigo Facility	Turbine (7FA)	1984	0.011	Good Combustion
	Duct Burner	575	0.012 (CT + DB)	
PSEG Lawrenceburg, IN	Turbine (7FA)	1906.4	0.0096	Good Combustion
	Duct Burner	310		
Selkirk Cogen., NY	Turbine	1173	0.012	Good Combustion
	Duct Burner	206		
Whiting Clean Energy, IN	Turbine	1735	0.0104	Good Combustion
	Duct Burner	821		
LSP Nelson, IL	Turbine	2166	0.0193	Good Combustion
	Duct Burner	350		
LSP Kendall, IL	Turbine	2166	0.0183	Good Combustion
	Duct Burner	350		
Gordonsville Energy, VA	Turbine	1430	0.0035*	Good Combustion
Duke Power Lincoln, NC	Turbine	1313	0.0038*	Good Combustion
CP&L Harstville, SC	Turbine	1521	0.0039*	Good Combustion
Hardee Station, FL	Turbine	1268	0.0039*	Good Combustion
CP&L Goldsboro 1, NC	Turbine	1908	0.0047*	Good Combustion
CP&L Goldsboro 2, NC	Turbine	1819	0.0049*	Good Combustion
Ecoelectrica L.P., PR	Turbine	1900	0.005*	Good Combustion
SMEPA-Mosell, MS	Turbine	1299	0.0057*	Good Combustion
Saranac Energy, NY	Turbine	1123	0.0062*	Good Combustion
Lakewood Cogen, NJ	Turbine	1073	0.0023	Good Combustion

* These limits do not include condensable PM_{10} (Method 202)

Compliance with the particulate matter limits presented in the above table is demonstrated based on measurement of either the filterable particulate fraction only or the combined filterable and condensable particulate fractions. Because the majority of the filterable particulate is PM_{10}, and because vendor information indicates that at least half of the total particulate is condensable, the limits based solely on demonstrating compliance using only the filterable component were considered non-representative for the purpose of comparison. Therefore, these limits were eliminated from the review.

Two other facilities that have lower limits than the proposed ABEC facility are Whiting Clean Energy and Lakewood Cogeneration. The Whiting Clean Energy facility is located in a PM_{10} nonattainment area and, therefore is subject to LAER and PM_{10} emission reduction credits. The source took a lower limit in order to avoid PM_{10} offset credits. While the Lakewood Cogeneration facility has a lower PM_{10} emission limit, the test methodology could not be verified to determine if both front half and back half had been captured in the stack testing. Additionally, the corresponding NO_X and CO emission are higher than the proposed ABEC facility. It is not expected that the proposed ABEC facility will emit more particulate matter than these two facilities because there is no feasible add on control technology for combustion turbine. The top level of control for a combustion turbine is considered to be clean burning fuel. Natural gas is the cleanest burning fuel and is therefore considered the best control technology.

As stated above, the combustion of natural gas generates negligible amounts of particulate matter. There is a degree of variability inherent to the test method (Method 202) used to determine compliance with the proposed particulate limits. The variability from this test result is from several factors. First, there is such a large volume of exhaust gas stream compared to small amount of particulate. For example, the concentration of particulate matter could be the same for two gas steams, however, if one of the gas streams is at a lower flow rate the pound per hour emission rate would be less than a gas stream that is at a higher flow rate. Second, there is a possibility of human error, which have 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 with the inlet combustion air will also leave the exhaust stack. The higher the background concentration of particulate matter in the ambient air the more will pass through the combustion turbine stack. Ambient air particulate concentration can vary depending on location, activity in the area, and weather conditions.

Conclusion – Based on the information presented above, the PM/PM_{10} BACT shall be the use of natural gas as the sole fuel and good combustion practice. The PM/ PM_{10} emissions from each turbine shall not exceed 0.012 lb/MMBtu, which is equivalent to 23 pounds per hour of PM/PM_{10} emissions, where PM_{10} includes filterable and condensable material.

(2) NO_X BACT Review

The oxides of Nitrogen (NO_X) emissions from combustion turbines are 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 in the primary combustion zone. The rate of thermal NO_X formation is an exponential function of the flame temperature. The fuel NO_X is formed by the gas-phase oxidation of char nitrogen. The fuel NO_X formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on nitrogen content of the fuel and the combustion oxygen levels. Fuel NO_X is insignificant because natural gas contains a negligible amount of fuel Nitrogen. Only thermal NO_X is formed during natural gas combustion at these sources.

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

Dry Low NO_X Burners
Water/Steam Injection
$SCONO_X$ System
Selective Catalytic Reduction (SCR)

Catalytic Combustion (XONON)

Technically Infeasible Control Options – Two of the control options were considered to be technically infeasible: water/steam injection, and catalytic combustion (XONON). The water and steam injection directly into the flame area of the turbine combustor provides a heat sink that lowers the flame temperature and reduces thermal NO_X formation. The water or steam injection rate is typically described on a mass basis by a water-to-fuel ratio or a steam-to-fuel ratio. Higher water-to-fuel or steam-to-fuel ratios translate to greater NO_X reductions, but may also increase emissions of CO and other hydrocarbons, reduce turbine combustion efficiency, increase maintenance requirements and cause potential flame outs. The water or steam injection limit NO_X emissions to 25 ppm @ 15% O_2. The proposed Westinghouse 501F turbines will be equipped with DLN combustors that reduce NO_X to 15 ppm at 15% O_2, which is lower than that attainable with wet control. Therefore, this control alternative utilizing water or steam injection will be excluded from further BACT consideration for the source.

The catalytic combustion (XONON) is a recently developed front-end technology that relies on flameless combustion of fuel to reduce NO_X emissions. The XONON system prevents the formation of thermal NO_X during combustion of the fuel by oxidizing a fuel/air mixture across small catalyst beds to burn fuel at less than the flame temperature at which thermal NO_X formation begins. The system does use a partial flame downstream to complete the combustion process, thus, producing small amounts of NO_X emissions. XONON technology replaces the traditional diffusion or lean premix combustion cans in the combustion turbine. This represents the only catalytic control that may lend itself for a reasonable retrofit to existing units. This technology has only been demonstrated on and being offered for small turbines (i.e. no larger than 1.5 MW). Additionally the RBLC does not list any entries for catalytic combustion as BACT for combustion turbines.

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

Rank	Control	Facility	Control Efficiency	Emission Limit (ppm)
1	SCONOx w/Dry Low NOx Burners	Turbine	90+	2.0-4.5
2	SCR w/Dry Low NOx Burners	Turbine	80-90+	2.5-4.5
3	Dry Low NOx Burners	Turbine	N/A	9-15

Discussion – The 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 the reduced residence time combustors, the dilution air is added sooner than with the standard combustors resulting in the combustion gases being at high temperature for a short time. This reduces the rate of thermal NO_X formation. The dry low-NOx burners are an integral design feature to the 501F turbines. Based on vendor specifications, the combustion turbines can achieve an emission limit of 15 ppm.

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 could reduce NO_X emissions 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 by regenerated. To regenerate the potassium coating it is contacted with a reducing gas, hydrogen, in the absence of oxygen. During the regeneration process, 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, four percent hydrogen in an inert carrier gas of nitrogen or steam is introduced. An absence of oxygen is necessary to retain the reducing properties necessary for regeneration. Hydrogen reacts with potassium nitrites and nitrates during regeneration to from H_20 and N_2 that is emitted from the stack.

The SCONOx catalyst is subject to the same fouling and masking degradation that is experienced by any other catalyst operating in a turbine exhaust stream. Trace impurities either ingested from ambient air or from internal sources accumulate on the surface of the catalyst, eventually masking active catalyst sites over time. The normal catalyst aging is also experienced with as is the case 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 used 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 are also long term maintenance and reliability concerns related to the mechanical components on the large-scale turbine projects. This is due to the number of parts that must operate reliably within the turbine exhaust environment.

The SCONOx process is dependent upon hot side dampers and gas seals, which must-cycle every 10 to 15 minutes. The moving parts, mechanical linkages, activators and damper seals, which must operate reliably within a hostile flue, gas environment. The long term reliability and economics of this system are not known at this time.

The economic evaluation of SCONOx was also conducted in the application to check the cost effectiveness of this technology. Based on vendor quotes the cost per ton of NO_X removed was estimated to be $24,368. This cost is not considered to be economically feasible for the proposed facility.

Selective Catalytic Reduction (SCR)

The SCR system is a post combustion control technology. In this system ammonia is injected into the gas turbine exhaust, that reacts with NO_X in the presence of a catalyst to form water and nitrogen. Technical factors related to this technology include the catalyst reactor design, optimum operating temperatures, sulfur content of the fuel, and ammonia slip. The Sulfur content of the fuel can be a concern for systems that use an SCR system, because the catalyst promotes partial oxidation of sulfur dioxide to sulfur trioxide, which combines with water to form sulfur acidic mist. However, given pipeline quality natural gas, catalyst life can be expected to be reasonable.

The 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. For a typical SCR, catalyst manufacturers will guarantee a life of three years for low emission rate, high performance catalyst systems. Ammonia slip is also a consideration with an SCR system. 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 range, 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 higher NO_X emission reduction rate.

The NOx emissions from each 501F combustion turbine using DLN alone is at 15 ppmvdc at 15% O_2 is estimated to be 472 tons per year (at 105 lbs/hour). The SCR system will ensure emission at 3.00 ppmvdc or less. This will result in reduction of about 348 tons of NOx emissions from each unit.

The total annualized cost for SCR including the fixed cost and annualized operation cost is estimated at $2,673,766. Therefore, the cost effectiveness of this technology is $7683 per ton of NOx emissions reduced.

<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:

Combined Cycle Combustion Turbines

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm@15%O_2	Control Description
Proposed ABEC Facility – Westinghouse 501	Turbine	1867	3.0 (3-hr block average)	DLN + SCR
Duke Energy Kankakee, IL	Turbine	620 MW	4.5 on an hour average and 3.5 on 24-hr avg. with Duct Firing	DLN + SCR
Duke Energy Vigo LLC, IN	Turbine	1984	3.0 (3-hr block avg.) with or without duct firing	DLN + SCR
PSEG Lawrenceburg Energy Inc., IN	Turbine	1906	3.0 (3-hr block avg.) with or without duct burners	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.	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 + $SCONO_X$
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 NOx emission limit utilizing SCR. However, neither of these two sites has been constructed, so the 2.0 ppm limit has not been demonstrated in practice to be feasible so far. Additionally, these two facilities were located in nonattainment areas, therefore the sources were subject to LAER. Two other facilities have been permitted at 2.5 ppm, but only one of them is in operation (Sunlaw Cogeneration). This facility has CEM data to show that the unit can achieve 2.5 ppm utilizing SCONOx. The Sunlaw Congeneration facility at 32 MW is considerably smaller than the proposed ABEC facility rated at 640 MW. Also, the SCONOX technology has been demonstrated to be effective only on small turbines. However, as discussed above the SCONOX system has long term maintenance and reliability concerns related to mechanical components on large scale turbine projects. In addition, SCONOX was determined to be economically infeasible for the proposed ABEC facility.

SCR has become a widely used and accepted control technology for NO_X emission control for natural gas-fired combustion turbines. Facilities utilizing SCR have been permitted from 4.5 ppmvd @ 15% O_2 down to 2 ppmvd @ 15% O_2. The SPA Campbell Soup has been permitted utilizing SCR control, as required by a LAER determination and has been in operation for approximately 3 years. The CEMs data for the SPA Campbell Soup facility supports the emission rates of approximately 2.5 ppm from the turbine, based on a 3-hour block average. As noted before catalyst degrades with time, so the system may become less efficient as the catalyst ages. Also, the SPA Campbell Soup facility was a LAER determination. The difference between BACT and LAER is economic feasibility. The cost analysis showed that a 3.0 ppm NO_X emission rate using DLN and SCR systems is economically feasible.

<u>Conclusion</u> – Based on the information presented above, the NO_X BACT shall be the use of dry low NO_X combustor in conjunction with SCR control with an emission limit of 3.0 ppmvd at 15% O_2 based on a 3-hour block average. This emission limit is equivalent to 22.4 pounds of NO_X per hour for each combustion turbine.

The two combined cycle combustion turbines are organized in a power block. During periods of startup and shutdown (i.e. less than 70 percent load) the NO_X emissions from power block shall not exceed 1079 pounds per event (an event is one startup and one shutdown). An event shall not last longer than 4.16 hours for the power block. Also, the source will be limited to 210 events for each turbine (cold, warm or hot) per year. The total hours for events shall not exceed 585 per 12 consecutive month period rolled on monthly basis as determined at the end of each calendar month. Startup is defined as the period of time from initiation of combustion firing until the unit reaches steady state operation (i.e. loads greater than 70%). Shutdown is defined as that period of time from the initial lowering of the turbine output, with the intent to shutdown, until the time at which the combustion is completely stopped.

(3) CO BACT Review

The carbon monoxide emissions from the combustion turbines are as a result of incomplete combustion of natural gas. Improperly tuned turbines decrease combustion efficiency resulting in increased CO emissions. The control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperature 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 limit the impact of fuel staging on CO emissions.

<u>Control Options Evaluated</u> – The following control options were evaluated in this BACT review:

Oxidation Catalyst
Good Design/Operation

<u>Discussion</u> – The CO emission can be controlled by ensuring complete and efficient combustion of the fuel in the turbine. Complete combustion is a function of time, temperature and turbulence. The 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.

Oxidation Catalyst

The 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. The technical factors relating to this system include catalyst reactor design, optimum operating temperature, back-pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Typically, oxidation catalyst reactors operate in a temperature range of 700 to 900 ^{o}F. At temperature lower than this range CO conversion to CO_2 reduces rapidly and at higher temperature, the catalyst may be damaged. If operated at part load (during start-up and shut-downs), the less than optimum temperature can significantly reduce the control efficiency. The catalyst normally placed within the heat recovery steam generator (HRSG) to protect it from catalyst sintering. The cost of an oxidation catalyst can be high with the largest cost associated with the catalyst itself. The catalyst life varies, but typically a 3 to 6 year life span can be expected.

The CO emissions from each 501F combustion turbine using DLN are about 10 ppmvdc that is estimated to be 320 tons per year (at 42.3 lbs/hour). Approximately 148 tons per year will be emitted during startup and shutdown period. The oxidation catalyst will not be able to control these emissions because the turbine exhaust will not be in optimum temperature range. The oxidation catalyst system will ensure 90% efficiency of control for CO emission. This will result in reduction of 224 tons of CO emissions from each unit. These calculations are shown below:

CO emissions before oxidation catalyst (@ 42.3 lbs/hour)

$$= \frac{(8760 \text{ hours} - 585 \text{ hours (SU/SD)})}{2000} \text{ X } 42.3 \text{ lbs/hour} + 148 \text{ tons/year (SU/SD)}$$
$$= 320 \text{ tons/year}$$

CO emissions after Oxidation Catalyst considering 90% control (@ 12.7 lbs/hour)

$$= \frac{(8760 \text{ hours} - 585 \text{ hours (SU/SD)})}{2000} \text{ X } 4.23 \text{ lbs/hour} + \frac{148 \text{ tons/year (SU/SD)}}{2}$$

$$= 91 \text{ tons/year}$$

CO emissions reduction = 320 – 91 = 229 tons/year

The total annualized cost for CO including the fixed cost and annualized operation cost is estimated at $1,355,916. Therefore, the cost effectiveness of this technology is $6,457 per ton of CO emissions reduced.

The source has agreed to comply with CO emission limit of 6 ppm @ 15% O_2 from each combined cycle combustion turbine when operating under steady state condition. Therefore, the source is not required to install CO oxidation catalyst. If after the initial compliance determination test the source is found to be not complying with this limit, the source will install CO oxidation catalyst.

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.

Combined Cycle Combustion Turbines

Company	Facility	Throughput (MMBtu/hr)	Emission Limit ppm@15%O_2	Control Description
Proposed ABEC Facility – Westinghouse 501	Turbine	1867	6	Good Combustion
Duke Energy Kankakee, IL	Turbine	620 MW	4.0 without Duct Firing and 6.0 with Duct Firing	Good Combustion
Duke Energy Vigo LLC, IN	Turbine	1984	6.0 without Duct Firing and 9.0 with Duct Firing	Good Combustion
PSEG Lawrenceburg Energy Inc., IN	Turbine	1906	6.0 without Duct Firing and 9.0 with Duct Firing	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

Based on the review of other turbine projects within Region V, there are three facilities that have been permitted with a CO emission limit at or below 6.0 ppm. There are other facilities listed above that have CO emission rates slightly lower than the proposed facility. The difference in emissions for all projects listed above that propose to achieve a lower CO limit without an oxidation catalyst is due to different turbine models.

Three of the facilities, Dighton Power, Berkshire Power, and Gorham Energy, used an oxidation catalyst in CO attainment areas. Economic analyses preformed on these facilities showed that it was economically feasible to use an oxidation catalyst. A cost analysis for the proposed ABEC facility showed it would cost $6,457 per ton of CO removed. The costs of the projects listed above were around 1,000 to 1,200 dollars per ton of CO removed. The difference in the cost is a result of higher inlet CO concentration. 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 unviable 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.

<u>Conclusion</u> – Based on the information presented above, the CO BACT shall be the use of natural gas, good design/operation. Each combustion turbine shall not exceed 6 ppm CO emissions at 15% O_2 based on a 24-hour block average, which is equivalent to 27.3 pounds per hour.

Upon initial operation, the facility will have 6 months to evaluate the ability to achieve a CO limit of 6 ppmvd at 15% O_2 based on a 24-hour block average, without an oxidation catalyst. If this limit cannot be achieved after the 6 month evaluation period, the facility will have 12 months to install an oxidation catalyst and demonstrate compliance with the specified limit.

During periods of startup and shutdown (less than 70 percent load) the CO emissions from the power block shall not exceed 3935 pounds per event (an event is one startup and one shutdown).

(4) SO_2 BACT Review

The oxidation of the Sulfur in fuel results in the sulfur dioxide (SO_2) emissions from combustion turbines. The SO_2 emissions are directly proportional to the sulfur content of the fuel. The 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.

<u>Control Options Evaluated</u> – the following control options were evaluated in the BACT review:

Flue Gas Desulfurization System
Use of Low Sulfur Fuel

<u>Discussion</u> – A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. The FGD is an established technology principally on coal fired and high sulfur oil fired steam electric generating stations. The FGD systems have not been installed on natural gas fired combustion turbines because of technical and cost factors associated with treating large volumes of high temperature exhaust gas containing low SO_2 levels. FGD typically operates at an inlet temperature of approximately 400 to 500 ^oF. In addition, FGD systems are not typically effective for streams with low sulfur SO_2 concentrations such as natural gas fired sources. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2.

The FGD systems also have energy and environmental impacts associated with their operation. A significant amount of energy is required to operate a FGD system due to the pressure drop over the scrubbers. There are also environmental impacts due to the disposal of the spent reagent and the high water use required for a wet scrubbing system. For the technical, energy, and environmental reasons presented above, FGD was excluded from further consideration in the BACT analysis

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 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 CFR 60 Subpart GG). Natural gas combustion results in SO_2 emissions at approximately 1 ppmvd. Therefore, the low SO_2 emission rate resulting from the use of natural gas as the sole fuel represents BACT for control of the 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), good combustion practices. The SO_2 emission limit from each turbine shall not exceed 0.0034 lb/MMBtu, which is equivalent to 6.0 pounds SO_2 per hour.

(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. The 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 Design/Operation

Discussion – An oxidation catalyst designed to control CO would also provide control for VOC emissions. The level of control is dependent on the content of the natural gas. The same technical factors that apply to the use of an oxidation catalyst technology for control of CO emissions (narrow operating temperature range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for collateral control of VOC emissions.

Since an oxidation catalyst was shown not to be cost effective for control of CO, it would also not be cost effective for control of VOCs at a much lower emission rate (approximately 20 percent of the annual CO emissions) and lower control efficiency. An oxidation catalyst is therefore not considered BACT for the control of VOC emissions at the proposed ABEC facility.

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 similar operations that have been recently permitted.

Combined Cycle Combustion Turbines

Company	Facility	Throughput MMBtu/hr	Emission Limit lb/MMBtu	Control Description
Proposed ABEC Facility – Westinghouse 501	Turbine	1867	0.0034	Combustion Control
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	6 lb/hr	Combustion Control
Berkshire Power Development, MA	Turbine	1792	6.3 lb/hr	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	1100 MW	0.012	Combustion Control
	Duct Burner		0.019	

The RBLC does not list any entries that require an oxidation catalyst for a combined cycle operation reviewed under PSD BACT. Also, an oxidation catalyst would not be economically feasible because of the lower VOC emissions associated with new combustion technology. Some facilities listed above have VOC emission rates slightly lower than the proposed facility. The difference in emissions is due to different turbine models and site specific conditions. While the VOC emissions are lower for these facilities their corresponding NO_X and CO emissions are higher.

Conclusion - Based on the information presented above, the VOC BACT shall be the use of pipeline quality natural gas, good combustion practices. The VOC emission limit from each turbine shall not exceed 0.0034 lb/MMBtu, which is equivalent to 6.0 pounds VOC per hour.

(B) Two Natural Gas-Fired Simple Cycle Combustion Turbines

The ABEC facility will also have two General Electric LM6000 simple cycle combustion turbines at this location which will be used to meet the peek power demand. The maximum heat input rating for each of the combustion turbines is 423 million British thermal units (MMBtu) per hour on a lower heating value basis. The output of each combustion turbine, operating in simple cycle mode, is approximately 46 MW. As the simple cycle CTs will be used to meet the peaking demand only, the annual hours of operation will be less than 7,000 for both turbines combined.

(1) NO_X BACT Review

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

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

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

SNCR is a backend technology, which uses ammonia injection similar to SCR, but operates at a higher temperature range (1,600 to 2,200 ^oF). The reaction occurs without a catalyst, effectively reducing NO_X to nitrogen and water. Since the SNCR process does not require a catalyst the process is more economically attractive than other control technologies. The operating temperature range, however, is not compatible with the proposed turbine exhaust temperature, which is approximately 820 ^oF. Furthermore, this control technology has only been applied to boilers and incinerators, but not to large natural gas turbines. Therefore, this control technology is considered to be technically infeasible for the proposed combustion turbines.

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

Rank	Control	Facility	Emission Limit (ppmvd)	Control Efficiency
1	SCONOX	Turbine	2.0 – 4.0	+90%
2	Selective Catalytic Reduction (SCR)	Turbine	2.5 – 4.5	60% - 90%
3	Dry Low NO_X Burners w/FGR	Turbine	9	N/A
4	Water/Steam Injection	Turbine	25 – 75	N/A

Discussion

SCONOX

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

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

SCONOX is installed at the back end of the combustion units where exhaust temperatures are within the temperature window. The turbine exhaust gases from simple cycle turbines could be ducted to an air-to-air system, a water-to-air closed loop system or a waste recovery boiler system depending on the type of application. These heat exchanger systems are able to reduce the exhaust gas temperature to 650 ^{o}F. A blower is also required to provide all necessary cooling air to the heat exchanger. Currently, the research is being done to develop a high temperature SCONOX catalyst that will operate at greater than 700 ^{o}F exhaust gas temperature. This will eliminate a need for heat exchanger system. Currently, SCONOX has not been installed on turbines with exhaust temperatures higher than 700 ^{o}F. The GE LM 6000 exhaust temperature varies typically in the range of 800 ^{o}F – 900 ^{o}F. The low NO_X emission rate of 2.0 ppmvd will not be guaranteed for units that have an exhaust temperature above 700 ^{o}F.

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

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

Selective Catalytic Reduction (SCR)

Selective catalytic reduction is a NO_X control process, which uses a reaction with ammonia in the presence of a catalyst to from N_2 and H_2O. An important factor when using SCR is temperature. The common reduction catalyst for this technology requires low temperatures (400 – 800 ^{o}F) in order for the reaction to occur. Operating above maximum operating temperature results in the oxidation of ammonia to either NO_X or ammonia nitrate. The LM 6000 has a quick startup, which makes it a good choice for meeting the peak demand. Purging occurs during the first 3 minutes, and baseload flue gas composition is achieved in 7 minutes. This can result in thermal shock to the SCR system. Other inherent factors that could effect performance of the turbine and SCR system include increased turbine back pressure, exhaust temperature materials limitations, catalyst masking / blinding, catalyst failure, and high ammonia slip.

The exhaust from LM6000 will be within this operational range of the tungsten base catalyst, but the system would be subject to constant startups, typical of simple-cycle combustion turbine operation to peak demand only. This would result in significant metal fatigue and reduced catalyst life. The catalyst bed in the turbine exhaust path would limit the rapid startup sequence necessary to fully respond to frequent fluctuations in the peak power demand. Long term equipment life of the turbine transition piece, catalyst bed and support systems depend on limiting rapid and uneven heating during startup. The differential thermal expansion of ceramic or stainless steel causes internal stresses within the material that, with cycling, will result in premature failure. In case of combined cycle configuration, the presence of HRSG limits the thermal stress by limiting the rate of startups, allowing a steady and slow heat transfer to the materials before full load is achieved.

Based on a review of the RBLC and other sources there are four simple-cycle combustion turbine installations that presently operate with a high temperature catalyst. One of the facilities, located in Southern California, has experienced significant operational problems with the original system and has applied to the local Air Board for permission to remove the system. The second facility, located in Northern California, has very limited operation, and has no operational data to support the effectiveness of the SCR system. The third installation, located outside of Sacramento, has been utilizing SCR successfully at the facility. This facility uses GE LM 6000 turbines. It should also be noted that all three of these simple cycle operations using SCR are considerably smaller than the proposed facility and operate as base load units. Furthermore, SCR for simple cycle combustion turbines being operated for peaking operation, is not economically feasible. The fourth facility, Puerto Rico Power Authority, is equipped with three ABB GT11N turbines firing distillate oil using SCR for NO_X control. The facility has been in operation since 1997, but is currently in negotiation with EPA over their ability to consistently meet the 10 ppm NO_X outlet emission rate.

Ammonia slip is also a concern when operating at high temperatures. SCR manufactures estimate up to 20 ppm or more of unreacted ammonia emissions when operating at very high temperature levels. Cost to control NO_X emissions from simple cycle operations utilizing SCR control can be extensive. Using the methodology set forth in the Office of Air Quality Planning and Standards Alternative Control Techniques Document NO_X emissions control cost was estimated to be $22,700 per ton of NO_X removed. This estimate is based on removal from 25 ppm to 5 ppm. Approximately 12 tons of NOx emissions associated with the startup and shutdown are not controlled by SCR. Therefore a approximately 58 tons of NOx will be controlled using SCR. Based on the issues above and the lack of continuous compliance data to support the use of high temperature SCR to control NO_X emissions from simple cycle operations, SCR will be eliminated from further consideration in this BACT analysis.

Dry Low NOx Combustion

DLN lowers the flame temperature by air /fuel staging by decreasing the residence time in the combustor. This uses a fuel-lean combustion, which is sub-stoichiometric, where the additional air cools the flame and reduces the rate of thermal NOx formation. Reducing the residence time results in the combustion gases being at a high temperature for a shorter time, thus reducing the rate of thermal NOx formation.

The major components of the DLN combustor are arranged to form two staged combustion. Multiple primary fuel nozzles are located around the primary zone. A single secondary nozzle is located along the centerline of the combustor with the center body. A venturi assembly is also included in the second stage. The primary zone is used as a diffusion burning zone for ignition and low load operation. At a specific fuel / air ratio in the combustor, fuel is introduced through the secondary fuel nozzle and flame is established in the secondary zone of the combustor. Consequently, NOx emissions are lower in lean combustion mode.

General Electric (the manufacturer of GE LM 6000 combustion turbine) in a letter to the source has stated as follows:

“The LM 6000 gas turbine is commercially available with two distinct combustion systems. The first model, designated LM6000-PC, uses a combustor derived directly from those used for flight applications with one annulus of fuel nozzles commonly referred to as a single annular combustor. This model uses water or steam injected through the fuel nozzles as diluents to maintain the optimum flame temperature in the combustion process in order to control emissions.

The alternative model, designated LM 6000-PD, uses a triple annular design to achieve emission control, and is know as the dry low emission combustor. This model is capable of operating with low emissions by using compressed air from the discharge of the gas turbine's high pressure compressor as the diluent to control the flame temperature and therefore emissions generated during the combustion process.

For either of these models, GE's standard offering has been to guarantee emissions of 25 ppm. It should be noted that with aero-derivative gas turbine technology and the inherent higher pressure ratios across the compression section, the temperature of the air entering the combustor are significantly higher than the air entering the combustion section of the a heavy duty "frame type" gas turbine. Therefore the ability to achieved lower emission is a much greater challenge. However the advantage of having these higher pressure ratios and temperature is a 25% increase in thermal efficiency, with 20% less air flowing through the gas turbine."

As stated in the GE's letter the guaranteed NOx emission limit for this type of operation is 25 ppm with or without the DLN combustor. Therefore, there is no environmental advantage by using DLN in place of Water / Steam Injection. Therefore, DLN technology is not considered further in this review.

Water Injection

Water injection is the conventional NOx control technology that reduces the formation of thermal NOx. Functioning as a thermal blast, water or steam is injected into the combustion zone, which decreases the flame temperature. As long as it occurs in the primary combustion zone, steam or water can be injected into either the fuel, the combustion air, or directly into the combustion chamber. Typically, the higher the ratio of either water or steam to fuel, the greater the reduction of NOx emissions. Wet injection has achieved demonstrated NOx emissions to 25 ppmvd.

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

Simple Cycle Combustion Turbines

Company	Facility	Throughput	Emission Rate (ppm@15%O2)	Control Description
Proposed ABEC Facility – GE LM 6000	Turbine	400 MMBtu/hr	25	Water Injection
PSEG Fossil LLC, NJ – GE LM 6000	Turbine	400 MMBtu/hr Total 170 MW	25	Water Injection – Not Subject to PSD
KM Power, MI – GE LM 6000	Turbine	550 MW	22	Water Injection
Black Hills Power and Light, SD – GE LM 6000 PD	Turbine	80 MW	25	Dry Low NO_X Combustor
Omaha Public Power – Pratt and Whitney FT-8	Turbine	100 MW	25	Water Injection
Auburndale Power Partners, FL	Turbine	1214 MMBtu/hr	15	Dry Low NO_X Combustor
Florida Power Corp. Polk County Site, FL	Turbine	1510 MMBtu/hr	12	Dry Low NO_X Combustor
Santa Rosa Energy LLC, FL	Turbine	241 MW	9.8	Dry Low NO_X Burner
Baltimore Gas & Electric, MD	Turbine	140 MW	15	Dry Low NO_X Burners
Oleander Brevard, FL	Turbine	170 MW	9	Dry Low NO_X Combustor
Tenaska, GA	Turbine	170 MW	15	Dry Low NO_X Combustor
JEA Baldwin, FL	Turbine	170 MW	10.5	Dry Low NO_X Combustor

In the above table, the sources listed with NOx emissions rate below 25 ppm are “Frame type” combustion turbines which are larger units and have Dry Low NOx combustors for combustion control. The frame type turbines with DLN combustors are able to meet 9 ppm limit. The GE LM 6000 turbines are “aero-derivative type” and are lighter and smaller then frame type. The Dry Low Emission (DLE) combustor available for this model does not guarantee NOx emissions below 25 ppm as stated in the letter from General Electric. As the emissions from DLE combustor are same as water injection, the company is proposing water injection for controlling NOx.

The GE LM 6000 combustion turbines will be used to meet peak power demand only. These demands are typically short duration and require rapid startup capability. Large base load capital intensive power generation turbines are not well suited to meet this peaking need and, when used in this service, result in higher power cost to consumer. Conversely, “aero-derivative” gas turbines are modified aircraft engines for use in power generation, and have features that make them well suited for peaking application when operated in simple cycle.

KM power is the only permit listed in the above table with limitation lower than 25 ppm using aero-derivative turbines. The 22 ppm limit in this permit is based on 12 month rolling average basis. The 24 hour average for these turbines is 25 ppm same as this project. The KM power permit does not contain any limitation on annual hours of operation unlike this project, which is limited to 7000 hours of operation (approximately 3500 hours for each simple cycle turbine) for simple cycle combustion turbines.

Conclusion – Based on the information presented above, the NO_X BACT for the proposed facility will be the use of natural gas as fuel, and water injection in the primary combustion with a limit of 25 ppmvd corrected to 15% O_2 based on a 24 operating hour averaging period. This is equivalent to 42 lb per hour of NOx emission per turbine.

During periods of startup and shutdown (less than 70 percent load) the NO_X emission for combustion turbine shall not exceed 36 pounds per event (an event is one startup and one shutdown). Also, the simple cycle combustion turbines shall be limited to 500 events per year. An event shall not last longer than 0.35 hour. This limit is equivalent to 9 tons per year of NO_X emissions per simple cycle turbine. The total hours for events shall not exceed 175 per 12 consecutive month period rolled on monthly basis as determined at the end of each calendar month. Startup is defined as the period of time from initiation of combustion firing until the unit reaches steady state operation (i.e. loads greater than 70%). Shutdown is defined as that period of time from the initial lowering of the turbine output, with the intent to shutdown, until the time at which the combustion is completely stopped.

(2) CO BACT Review

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

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

CO Catalyst Oxidation System
Improved Air/Fuel Mixing w/Good Design and Operation

Discussion

CO Catalytic Oxidation System

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

RBLC and other states have confirmed that catalytic oxidation has not been required for simple cycle peaker operation reviewed under PSD BACT.

The high-temperature oxidation catalyst is rated up to 1200 F, which is within the exhaust gas temperature range of the LM 6000. The oxidation catalyst creates a pressure drop across the system. Typical pressure drop across an oxidation catalyst designed for the simple cycle CT is in the range of 2-3 inches of water column. This can result in reduction in operational efficiency of the turbines.

The annual CO emissions from each LM6000 (excluding the startup and shutdown emission) are estimated to be 60 tons based on 3500 operating hours per year. With the highest efficiency of control (90%), installing CO oxidation catalyst will reduce 54 tons of CO emissions. The total annualized cost for installing an oxidation catalyst to LM 6000 turbine is $575, 613. This results in cost-effectiveness of about $10,659 per ton of CO removed. This cost is economically infeasible for this kind of operation.

Improved Air/Fuel Mixing w/Good Design and Operation

Improved air/fuel mixing with good design/operation is the next type of combustion control evaluated. The Frame type combustion turbine models have lower CO emissions than the aero-derivative type models due to design difference. The main component of the design that makes the CO emissions less than is the post flame temperature. The hotter temperature results in more burning of CO emissions. For this facility the data from GE indicates that emissions will be below 25 ppmvd corrected to 15% O_2, at steady state conditions for ambient temperatures above 70^{o}F. As the ambient temperature drops the CO emissions start to increase. For the ambient temperature in range of 30^{o}F to 70^{o}F, the CO emissions are up to 50 ppm, and at 75 ppm for ambient temperature in range of 0^{o}F to 30^{o}F and up to 100 ppm for temperature below 0^{o}F. Even though a higher CO emission limit is allowed to account for extreme cold season, the days with temperature dipping below 30^{o}F on a 24 hour block average basis are rare. For the majority of operating period in a year the temperature is expected to stay above this threshold and CO emissions shall be limited to less than 50 ppmvd. Proper operation, temperature, and oxygen availability will also minimize CO spikes during normal operation.

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

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed ABEC Facility – GE LM 6000	Turbine	423 MMBtu/hr	25	Ppm	Good Combustion
PSEG Fossil LLC, NJ – GE LM 6000	Turbine	400 MMBtu/hr Total 170 MW	70	Ppm	Not subject to PSD
KM Power, MI – GE LM 6000	Turbine	550 MW	79	Lb/hour	Good Combustion
TNP Lordsburg, NM – GE LM 6000	Turbine	40 MW	18	Ppm	Good Combustion
Black Hills Power and Light, SD – GE LM 6000 PD	Turbine	80 MW	25	Ppm	Good Combustion
Omaha Public Power – Pratt and Whitney FT-8	Turbine	100 MW	69	Lb/hour	
RockGen Energy, WI	Turbine	NA	12	Ppm	DLN Combustors
LS Power Nelson, IL	Turbine	2166	0.047	Lb/MMBtu	DLN Combustors
LS Power Kendall, IL	Turbine	2166	0.045	Lb/MMBtu	DLN Combustors
Auburndale Power Partners, FL	Turbine	1214	15	Ppm	Good Combustion
Champion Intl. Clean Energy, ME	Turbine	175 MW	9	Ppm	NA
Doswell L.P., VA	Turbine	1261	25	lb/hr	Combustor Design
Lakewood Cogeneration, NJ	Turbine	1190	30.94	lb/hr	Turbine Design
Portland General Electric, OR	Turbine	1720	15	Ppm	Good Combustion
Selkirk Cogeneration L.P., NY	Turbine	1173	10	Ppm	Combustion Control

The ABEC facility operates the GE LM 6000 turbines in simple cycle mode. These are peaking units that are limited in hours of operation to 7000 per year for both turbines (3500 hours per year of operation per turbine). As previously shown, add on controls (oxidation catalyst) are economically infeasible for this kind of operation.

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

Ambient temperature range	CO emissions concentration in ppmvd at 15% O_2
Greater than 70°F	25
From 30°F to 70°F	50
From 0°F to 30°F	75
Less than 0°F	100

During periods of startup and shutdown (less than 70 percent load) the CO emissions for LM 6000 combustion turbine shall not exceed 29.2 pounds per event (an event is one startup and one shutdown). Also, the LM 6000 combustion turbines shall be limited to 500 events per year. This limit is equivalent to 7.3 tons per year of CO emissions from each simple cycle combustion turbine.

(3) PM/PM10 BACT Review

The add-on control for PM/PM10 emissions from the combustion turbine have been discussed in detail in the previous section for combined cycle turbines. The add-on controls are not technically feasible for this operation also.

Conclusion – The PM BACT shall be the use of natural gas and good design and operation. The total PM emissions from each turbine shall not exceed 0.00675 lb/MMBtu (2.7 pounds per hour) on a lower heating value basis.

(4) SO_2 BACT Review

Emissions from natural gas-fired turbines are low because pipeline quality gas has a low sulfur content. A properly designed and operated turbine utilizing a low sulfur natural gas will have low SO_2 emissions.

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

Wet Lime Scrubber
Spray Dryer–ESP/Lime Injection-ESP

Discussion – A wet lime scrubber uses a lime solution as a scrubbing medium to control SO_X emissions. Lime scrubbers have been widely used to control SO_X from power plants, however those installed have typically been at coal-fired and other high sulfur oil-fired combustion units. The addition of a wet lime scrubber would require the addition of fuel to control the exit gas stream to eliminate a wet plume effect. Therefore, additional fuel would be required to create a dry plume, thus increasing emissions of other pollutants. In addition, a wet scrubber creates solid waste, which first must be dewatered, and then landfilled.

Spray dryer-ESP technology uses a lime slurry which is injected by a spray dryer in the flue gas in the form of fine droplets. The droplets absorb SO_X from the flue gas and then become dry particles due to the evaporation of water. The dry particles are then captured by and ESP downstream of the spray dryer.

Both of the listed control options are economically infeasible, with the cost per ton of SO_X removed between six and ten million dollars. The RBLC lists many entries with a fuel specification of natural gas, good combustion practices and good design and operation. A properly designed and operated turbine using low sulfur natural gas is an effective control technology available for the control of SO_X emissions from boilers.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of low sulfur natural gas (less than 0.8 percent sulfur by weight), and good combustion practices. The SO_X emission limit from each turbine shall be less than 0.0035 pounds per MMBtu.

(5) VOC BACT Review

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good control.

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

Thermal Oxidation
Catalytic Oxidation
Good Design/Operation

Discussion – Thermal oxidation is a proven technology to control VOC emissions, however it is rarely used on natural gas-fired sources. Because of the low VOC concentration generated from the use of natural gas and good combustion practice, thermal oxidation technology is ineffective. In addition, the thermal oxidation technology requires additional combustion of natural gas, which in turn would generate more emissions.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbon to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion ranges from 650 to 1000 ^oF. In addition the use of an oxidation catalyst would require additional combustion of natural gas, which increase NO_X and CO emissions.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for combustion turbines:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed ABEC Facility – GE LM 6000	Turbine	423 MMBtu/hr	0.02	lb/MMBtu	Combustion Control
Carolina Power and Light, NC	Turbine	1907.6	0.0015	lb/MMBtu	Combustion Control
Duke Power Co. Lincoln Turbine Station	Turbine	1313	0.0015	lb/MMBtu	Combustion Control
Auburndale Power Partners	Turbine	1214	0.005	lb/MMBtu	Combustion Control
Berkshire Power Development, MA	Turbine	1792	0.0035	lb/MMBtu	Combustion Control
Duke Power Lincoln, NC	Turbine	1247	0.004	lb/MMBtu	Combustion Control
Florida Power Corporation Polk County, FL	Turbine	1510	7	ppmvw	Good Combustion
[1]LS Power Kendall, IL	Turbine	2166	0.0099	lb/MMBtu	Good Combustion
[1]LS Power Nelson, IL	Turbine	2166	0.0104	lb/MMBtu	Good Combustion

[1]Combined cycle project starting in simple cycle operation. The emission rate is for simple cycle operation

The RBLC does not list any entries that require an oxidation catalyst for a simple cycle operation reviewed under PSD BACT. Also, an oxidation catalyst would not be economically feasible because of the lower inlet CO emissions associated with new combustion technology. The Duke Power Lincoln and Carolina Power & Light generation plants have VOC emission rates lower than the proposed facility. The difference in emissions is due to different turbine models and site specific conditions. While the VOC emissions are lower for these two facilities their corresponding NOX and CO emissions are higher.

Conclusion – Based on the information presented above, the VOC BACT for each turbine shall be good design and operation. Each combustion turbine shall be limited to 0.02 lb/MMBtu (on a lower heating value basis), which is equivalent to 8 lb/hr VOC.

(C) Auxiliary Boiler

The auxiliary boiler has a maximum heat input capacity of 21 MMBtu per hour, and will exclusively use natural gas as fuel. The purpose of the auxiliary boiler is to provide heat to the heat recovery steam generator (HRSG) steam drums during startup periods to prevent lengthy cold startups thus reducing the increased emissions associated with startup conditions and also prevent freeze conditions in the winter. 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 HRSGs are shut down. Boiler operation will not occur when the combined cycle combustion turbines are shut down except during short overlapping period.

(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. Due to the fact that natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate mater from natural gas combustion has both filterable and condensible fractions. The particulate matter generated from natural gas combustion is usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

There are two sources of condensible particulate emissions form combustion sources: condensible organic 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)
Electrostatic Precipitator (ESP)
Wet Scrubber

Technically Infeasible Control Options – All control options are basically technically infeasible because the sole fuel for the proposed auxiliary boilers is natural gas, which has little to no ash that would contribute to the formation of PM or PM_{10}. Add-on controls have never been applied to commercial natural gas fired boilers, therefore, add on particulate matter control equipment will not be 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 ABEC Facility	Boiler	21	0.0075	lb/MMBtu	Good Design and Operation
Duke Vigo Facility	Boiler	46.6	0.0075	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
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 BACT for PM/PM_{10} listed in the RBLC for natural gas fired boilers is combustion control. All of the above listed entries utilize a fuel specification of natural gas or good design and operation (i.e. good combustion). As stated above PM/PM_{10} emissions from natural gas fired sources are low, making add on PM/PM_{10} control both economically and technically infeasible.

Conclusion – Based on the information presented above the PM/PM_{10} BACT for the auxiliary boiler is good combustion practice, and the use of natural gas as its only fuel. The PM/PM_{10} emissions from the 21 MMBtu/hr auxiliary boiler shall not exceed 0.0075 lb/MMBtu, which is equivalent to 0.1575 pounds per hour.

(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 were evaluated in the BACT review:

Flue Gas Recirculation (FGR)
Low NOx Burners

Discussion – Flue Gas Recirculation (FGR) incorporates the recirculation of 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.

Low NOx burners are a specially designed burner that employ a two staged combustion within the burner. Primary combustion typically occurs at a lower temperature under oxygen deficient conditions and secondary combustion is completed with excess air.

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 ABEC Facility	Boiler	21	0.049	lb/MMBtu	Good Design and Operation
Duke Vigo, IN	Boiler	46.6	0.049	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

Based on the RBLC review, there are two facilities, with similar heat input capacity, that have been permitted with a lower NO_X emission limitation than the proposed facility. The Darling International facility utilizes Low NO_X burners along with flue gas recirculation to achieve lower limits. This facility is located in a nonattainment area, therefore LAER was applied. The other facility that utilizes a flue gas recirculation system to obtain a lower limit then the proposed facility is the Kamine/Beiscorp Corporation site in New York. The boiler at this facility is of similar size, however, it does not employ low NO_X burners. As a result, there is a higher NO_X exhaust concentration, making flue gas recirculation system economically feasible. There are several larger boilers that have been permitted with a flue gas recirculation system, however, a larger boiler will have a higher NO_X emission rate, therefore making a flue gas recirculation system economically feasible.

Conclusion – Based on the information presented above, the NO_X BACT shall be the use of Low NO_X burner design in conjunction with a fuel specification of natural gas only. The NO_X emissions from the boiler shall not exceed 0.049 lb/MMBtu, which is equivalent to 1.029 pounds per hour.

(3) SO_2 BACT Review

Sulfur dioxide emissions from natural gas-fired combustion sources are low because pipeline quality gas has a low sulfur content. A properly designed and operated boiler utilizing low sulfur natural gas will insure minimal SO_2 emissions.

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

Flue Gas Desulfurization System
Use of Low Sulfur Fuel

Discussion – A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber. Lime is injected by a spray dryer into the flue gas in the form of fine droplets under well-controlled conditions such that the droplets will absorb SO_2 from the flue gas and then become dry particulate due to evaporation of water. A particulate control device then captures the dry particulate. The captured particles are removed from the system and disposed.

This control option will generate dry solid waste, consisting mainly of lime and $CaSO_4$. This waste must be disposed of in a solid waste landfill, giving this option additional environmental concerns. Removal efficiencies decrease as the amount of sulfur contained in the fuel decreases. Also pipeline quality natural gas contains very little sulfur, thus making any FGD economically infeasible. Based on additional environmental concerns with the FGD solid waste, low sulfur removal efficiencies, and cost to control, FGD will be eliminated further from this BACT analysis.

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. Therefore, the very low SO_2 emission rate that results from the use of natural gas as the sole fuel represents BACT for control of SO_2 emissions from the auxiliary boiler.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of natural gas (less than 0.8 percent sulfur by weight) which is inherently low in sulfur, good combustion practices. The SO_X emission limit from the boiler shall not exceed 0.0006 lb/MMBtu, which is equivalent to 0.012 pounds per hour.

(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 were evaluated in this BACT review:

Good Combustion Control

Discussion – Good combustion practice is the considered BACT for CO control on natural gas fired boilers. 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.

Existing BACT Emission Limitations – The EPA RBLC 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 ABEC facility	Boiler	21	1.7	lb/hr	Good Design and Operation
Duke Vigo, IN	Boiler	46.6	3.82	lb/hr	Good Design and Operation
Air Liquide America Corp, LA	Boiler	95	3.7	lb/hr	Good Design and operation
Mid-Georgia Cogen., GA	Boiler	60	3	lb/hr	Complete Combustion
Archer Daniels Midland Co., IL	Boiler	350	14	lb/hr	Good Combustion practices
Darling International, CA	Boiler	31.2	2.8	lb/hr	Good Combustion
Indeck Energy, MI	Boiler	99	14.85	lb/hr	Combustion Control
Kamine/Besicorp, NY	Boiler	33	1.26	lb/hr	No controls
Lakewood Cogen., NJ	Boiler	131	5.5	lb/hr	Boiler Design
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

All of the entries listed in the above table list good combustion practice and good design/operation as CO BACT. As stated above CO emissions are a result of incomplete combustion of natural gas.

Conclusion – Based on the information presented above, the CO BACT shall be the use good combustion practice. Emissions from the boiler shall not exceed 0.082 lb/MMBtu, which is equivalent to 1.7 pounds per hour.

(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 do.

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

Thermal Oxidation

Catalytic Oxidation
Good Design/Operation

Discussion – Thermal oxidation is a proven technology to control VOC emissions, however it has never been used on natural gas-fired combustion source. Because of the low VOC concentration generated from the use of natural gas and good combustion practice the thermal oxidation technology is ineffective. In addition, the thermal oxidation technology requires additional combustion of natural gas, which result in additional environmental impacts; i.e., an in turn would generate more emissions.

Oxidation catalyst technology uses precious metal-based catalysts to promote the oxidation of CO and unburned hydrocarbon to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. The optimal operating temperature range for VOC conversion ranges from 650 to 1000^{o}F. In addition the use of an oxidation catalyst would require additional combustion of natural gas, which increase NO_X and CO emissions.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents the more stringent BACT emission limitations for boilers:

Company	Facility	Heat Input MMBtu/hr	Emission Rate		Control Description
Proposed ABEC facility	Boiler	21	0.11	Lb/hr	Good Design and Operation
Duke Vigo, IN	Boiler	46.6	0.25	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 0.11 lb/hr, is one of the lowest emission rates.

Conclusion – Based on the information presented above, the VOC BACT for the auxiliary boiler at the proposed facility shall be good design and operation. Emissions from the boiler shall not exceed 0.0054 lb/MMBtu, which is equivalent to 0.12 pounds per hour.

(D) Cooling Tower

Evaporative cooling towers are designed to cool process cooling water by contacting the water with air, and evaporating some of the water. Thus, these units use the latent heat of water vaporization to exchange heat between the process air and the air passing through the tower. This type of cooling tower typically contains a wetted medium to promote evaporation, by providing a large surface area and/or by creating many water drops with a large cumulative surface area. Some of the liquid water may be entrained in the air stream and be carried out of the tower.

(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. Particulate emissions from towers are controlled by installing drift eliminators, devices that are designed to minimize total liquid drift (dissolved solids on water droplets from evaporative cooling towers).

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Control Options Evaluated

Drift Eliminators

Discussion – The technologies available to control PM_{10} emissions from evaporative cooling towers are limited to devices that minimize drift. Drift eliminators represent the top level of PM control technology for cooling towers. Drift eliminators consists of several layers of plastic chevrons located within the tower to knock out and coalesce fine water droplets before they can be emitted to the atmosphere.

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 ABEC Facility	Cooling Tower (9 cell)	Drift Eliminator	0.0005	0.49	N/A
Duke Vigo, IN	Cooling Tower (4 cell)	Drift Eliminator	0.0006	0.18	N/A
Crown/Vista Energy, NJ	Cooling Tower	Drift Eliminator	0.1	5.9	None Required
Texaco Bakersfield	Cooling Tower	Cellular Type Drift Eliminator	---	1.26	None Required
Ecoelectrica LP, PR	Cooling Tower	2-Stage Drift Eliminator	0.0015	60	None Required
Lakewood Cogen, NJ	Cooling Tower	Drift Eliminator	0.002	0.874	None Required
Crystal River, Units 1,2,3, FL	Cooling Tower	High Eff. Drift Eliminator	0.004	428	None Required
Crystal River, Units 4,5, FL	Cooling Tower	High Eff. Drift Eliminator	---	175	None Required

Emissions of particulate matter from cooling towers are created when water droplets escaping the tower evaporate, and the dissolved and suspended solids within these droplets become airborne. 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.

<u>Conclusion</u> – 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 0.0006 percent. The total particulate emissions from the cooling towers shall not exceed 0.49 pounds per hour