CONSTRUCTION PERMIT
PREVENTION OF SIGNIFICANT DETERIORATION (PSD)
OFFICE OF AIR MANAGEMENT

Vermillion Generating Station
CR 300 N and SR 63
Eugene Township, Indiana 47928

This permit is issued to the above mentioned company (herein known as the Permittee) under the provisions of 326 IAC 2-1, 326 IAC 2-2, 40 CFR 52.780 and 40 CFR 124, with conditions listed on the attached pages.

Construction Permit No.: PSD-165-10476-00022	
Issued by: Paul Dubenetzky, Branch Chief Office of Air Management	Issuance Date:

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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 Management (OAM), and presented in the permit application.

A.1 General Information

The Permittee owns and operates a stationary merchant power plant.

Responsible Official:	Robert A. Schaffeld
Source Address:	CR 300 N and SR 63, Eugene Township, Indiana 47928
Mailing Address:	400 South Tyron Street, Suite 1800, Charlotte, NC 28202
SIC Code:	4911
County Location:	Vermillion
County Status:	Attainment for all criteria pollutants
Source Status:	Major Source, Part 70 Permit Program Major Source, under PSD Rules

A.2 Emission Units and Pollution Control Equipment Summary

This construction permit consists of the following emission units and pollution control devices:

(a) Eight (8) simple cycle, natural gas-fired combustion turbines, designated as units #1-#8, with a maximum heat input capacity of 1,272 mmBtu/hr each, a nominal output of 80 MW each, utilizing diesel fuel as a back-up fuel source, controlled by low-NOx combustors in conjunction with natural gas usage, controlled by wet-injection in conjunction with diesel fuel usage and exhausts to stacks designated as #1-#8.

(b) Two (2) Emergency diesel generators, designated as units #9 and #10, with a maximum heat input capacity of 17.21 mmBtu/hr each and exhausts to stacks designated as #9 and #10.

(c) One (1) emergency diesel fire pump, designated as unit #11, with a maximum heat input capacity of 1.6 mmBtu/hr and exhausts to a stack designated as #11.

(d) Four (4) diesel fuel storage tanks, designated as tanks #1-#4, with a maximum capacity of 519, 000 gallons per tank, a maximum volume of 69,400 ft3 per tank and exhausts to vents designated as #12-#15.

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

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

A.4 Acid Rain Permit Applicability [40 CFR Part 72.30]

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

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

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

(c) The source submitted their Phase II, Acid Rain permit application on March 9, 1999.

SECTION B GENERAL CONSTRUCTION AND OPERATION CONDITIONS

THIS SECTION OF THE PERMIT IS BEING ISSUED UNDER THE PROVISIONS OF 326 IAC 2-1 AND 40 CFR 52.780, WITH CONDITIONS LISTED BELOW.

Construction Conditions [326 IAC 2-1-3]

B.1 General Construction Conditions

(a) The data and information supplied with the application shall be considered part of this permit. Prior to any proposed change in construction which may affect allowable emissions, the change must be approved by the Office of Air Management (OAM).

(b) 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 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 from its issuance. If no public comments are received, then the permit shall be effective immediately upon issuance. Three (3) days shall be added to the thirty (30) day period, if service of notice is by mail.

B.3 Revocation of Permits [326 IAC 2-1-9(b)]

Pursuant to 326 IAC 2-1-9(b)(Revocation of Permits), the Commissioner may revoke this permit if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

B.4 Permit Review Rules [326 IAC 2]

Notwithstanding Condition B.11, all requirements and conditions of this construction permit shall remain in effect unless modified in a manner consistent with procedures established for modifications of construction permits pursuant to 326 IAC 2 (Permit Review Rules).

B.5 First Time Operation Permit [326 IAC 2-1-4]

This document shall also become a first-time operation permit pursuant to 326 IAC 2-1-4 (Operating Permits) when, prior to start of operation, the following requirements are met:

(a) The attached affidavit of construction shall be submitted to the Office of Air Management (OAM), Permit Administration & Development Section, verifying that the facilities were constructed as proposed in the application.

(i) The facilities covered in the Construction Permit may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM if the provisions of 40 CFR Parts 72-80 (Acid Rain Program) are not applicable to such facilities.

(ii) If the facilities are subject to the provisions of 40 CFR Parts 72-80 (Acid Rain Program), then the proper Phase II, Acid Rain permit must be issued to such facilities before operation can commence.

(b) 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.

(c) Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section and attach it to this document.

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

Operation Conditions

B.6 General Operation Conditions

(a) The data and information supplied in the application shall be considered part of this permit. Prior to any change in the operation which may result in an increase in allowable emissions exceeding those specified in 326 IAC 2-1-1 (Construction and Operating Permit Requirements), the change must be approved by the Office of Air Management (OAM).

(b) The Permittee shall 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 (IC13-17) and the rules promulgated thereunder.

B.7. Preventive Maintenance Plan [326 IAC 1-6-3]

Pursuant to 326 IAC 1-6-3 (Preventive Maintenance Plans), the Permittee shall prepare and maintain a preventive maintenance plan, including the following information:

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

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

(c) Identification of the replacement parts which will be maintained in inventory for quick replacement.

The preventive maintenance plan shall be submitted to IDEM, OAM upon request and shall be subject to review and approval.

B.8 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 Management (OAM) 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 OAM, 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].

B.9 Transfer of Permit [326 IAC 2-1-6]

Pursuant to 326 IAC 2-1-6 (Transfer of Permits):

(a) In the event that ownership of the eight (8) combustion turbines, two (2) emergency diesel generators, one (1) emergency diesel fire pump and four (4) storage tanks is changed, the Permittee shall notify OAM, Permit Branch, within thirty (30) days of the change. Notification shall include the date or proposed date of said change.

(b) The written notification shall be sufficient to transfer the permit from the current owner to the new owner.

(c) The OAM shall reserve the right to issue a new permit.

B.10 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 326 IAC 2-1 (Permit Review Rules).

B.11 Availability of Permit [326 IAC 2-1-3(I)]

Pursuant to 326 IAC 2-1-3(I), the Permittee shall maintain all applicable permits on the premises of the source and shall make this permit available for inspection by the IDEM, or other public official having jurisdiction.

B.12 NSPS Reporting Requirement

Pursuant to the New Source Performance Standards (NSPS), Part 60, Subpart GG, 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 Management
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-OAM. The requirements of 40 CFR Part 60 are also federally enforceable.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitation and Standards

C.1 PSD Major Source Status [326 IAC 2-2] [40 CFR 52.21]

(a) The potential to emit of nitrogen oxides (NOx) and carbon monoxide (CO)) for the facilities listed in this construction permit, are greater than 250 tons per year. Therefore, the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) shall apply to the source.

(b) Any change or modification which may increase the allowable emissions, potential emissions, or potential to emit, as appropriate, to the following:

1.) 25 tons per year or more (326 IAC 2-1),

2.) 10 tons per year for a single HAP or combination HAPs greater than 25 tons per year (326 IAC 2-1-3.4),

3.) Equal to or more than the significant emission rates as defined under 326 IAC 2-2-1 (Definitions),

from the equipment covered in this construction permit must be approved by the Office of Air Management (OAM) before such change may occur.

C.2 326 IAC 5 (Opacity Limitations):

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

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

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

C.3 Operation of Equipment [326 IAC 2-1-3]

All air pollution control equipment listed in this permit shall be in placed or operated at all times that the emission units vented to the control equipment are in operation, as described in Section D of this permit.

Testing Requirements

C.4 Performance Testing [326 IAC 3-6]

(a) 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 methods approved by IDEM, OAM.

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 Management
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) All test reports must be received by IDEM, OAM within forty-five (45) days after the completion of the testing. An extension may be granted by the Commissioner, if the source submits to IDEM, OAM, a reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Monitoring Requirements

C.5 Compliance Monitoring [326 IAC 2-1-3]

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, no more than ninety (90) days after receipt of this permit. If due to circumstances beyond its control, this schedule cannot be met, the Permittee shall notify:

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

in writing, no more than ninety (90) days after receipt of this permit, with full justification of the reasons for the inability to meet this date and a schedule which it expects to meet. If a denial of the request is not received before the monitoring is fully implemented, the schedule shall be deemed approved.

C.6 Monitoring Methods [326 IAC 3]

Any monitoring or testing performed to meet the requirements 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.

Corrective Actions and Response Steps

C.7 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 Management
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

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

(c) If the ERP is disapproved by IDEM, OAM, 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, OAM, 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, OAM, 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]

Record Keeping and Reporting Requirements

C.8 Annual Emission Reporting [326 IAC 2-6]

Pursuant to 326 IAC 2-6 (Emission Reporting), the Permittee must annually submit an emission statement for the source. This statement must be received by July 1 of each year and must comply with the minimum requirements specified in 326 IAC 2-6-4. The annual statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

The annual emission statement covers the twelve (12) consecutive month time period starting January 1 and ending December 31.

C.9 Monitoring Data Availability [326 IAC 2-1-3]

(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.10 General Record Keeping Requirements [326 IAC 2-1-3]

(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 and available within one (1) hour upon verbal request of an IDEM, OAM, representative, for a minimum of three (3) years. They may be stored elsewhere for the remaining two (2) years providing they are made available within thirty (30) days after written request.

(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 improper maintenance 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.

(d) All record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

C.11 General Reporting Requirements [326 IAC 2-1-3]

(a) 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 Management
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(b) 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, OAM, on or before the date it is due.

(c) Unless otherwise specified in this permit, any report shall be submitted within thirty (30) days of the end of the reporting period.

(d) 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) an emergency as defined in 326 IAC 2-7-1(12); 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.

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

(f) The first report shall cover the period commencing on the date of issuance of this permit and ending on the last day of the reporting period.

SECTION D.1 FACILITY CONDITIONS

(a) Eight (8) simple cycle, natural gas-fired combustion turbines, designated as units #1-#8, with a maximum heat input capacity of 1,272 mmBtu/hr each, a nominal output of 80 MW each, utilizing diesel fuel as a back-up fuel source, controlled by low-NOx combustors in conjunction with natural gas usage, controlled by wet-injection in conjunction with diesel fuel usage and exhausts to stacks designated as #1-#8.
(b) Two (2) Emergency diesel generators, designated as units #9 and #10, with a maximum heat input capacity of 17.21 mmBtu/hr each and exhausts to stacks designated as #9 and #10.
(c) One (1) emergency diesel fire pump, designated as unit #11, with a maximum heat input capacity of 1.6 mmBtu/hr and exhausts to a stack designated as #11.
(d) Four (4) diesel fuel storage tanks, designated as tanks #1-#4, with a maximum capacity of 519, 000 gallons per tank, a maximum volume of 69,400 ft3 per tank and exhausts to vents designated as #12-#15.

The information describing the source contained in this Section D.1 is descriptive information, and does not constitute federally enforceable conditions.

Emissions Limitation and Standards

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

Pursuant to 326 IAC 2-2 (PSD), this new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, and NOx, Be and H_2SO_4, because the potential to emit for these pollutants exceed the PSD major "significant" thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

D.1.2 Nitrogen Oxides (NOx) - Best Available Control Technology [326 IAC 2-2-3] for the eight (8) combustion turbines

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) Use Dry Low-NO_X combustors in conjunction with natural gas;

(2) Use Wet-Injection in conjunction with diesel fuel;

(3) When burning natural gas, the NOx emission rate shall not exceed a one (1) hour average concentration of 15 ppmvd of NOx at 15 percent O_2 in conjunction with dry low-NOX combustors;

(4) When burning natural gas, the NOx emission rate shall not exceed 12 ppmvd of NOx per year based over twelve (12) consecutive months of operation at 15 percent O_2 in conjunction with dry low-NOX combustors;

(5) When burning diesel fuel, the NOx emission rate shall not exceed a one (1) hour average concentration of 42 ppmvd of NOx at 15 percent O_2 in conjunction with wet-injection;

(6) The total input of the natural gas fuel to the eight (8) combustion turbines shall be limited to 20,336 MMCF per twelve consecutive month period, rolled on a monthly basis. This usage limitation is equivalent to 426.0 tons of NOx per year. If diesel fuel oil is combusted during any portion of a twelve (12) consecutive month period, natural gas usage shall be reduced such that NOx emissions for the eight (8) turbines do not exceed 732.8 tons per year for gas and oil firing combined, as determined by CEMS.

D.1.3 Sulfur Dioxide (SO_2) - Best Available Control Technology [326 IAC 2-2-3] for the eight (8) combustion turbines

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) Use natural gas as the primary fuel for the combustion turbines;

(2) The sulfur content of the diesel fuel used by the combustion turbines shall not exceed 0.05 percent by weight; and

(3) Use only diesel fuel oil as a back-up fuel source. The total input of the diesel fuel to the eight (8) combustion turbines shall be limited to 34,000 kilo-gallons per twelve consecutive month period, rolled on a monthly basis. This usage limitation is equivalent to 116.0 tons of SO_2 per year and 392.0 tons of NOx per year.

D.1.4 Carbon Monoxide (CO) - Best Available Control Technology [326 IAC 2-2-3] for the eight (8) combustion turbines

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) Combustion control maintaining the following emission limits:

(a) The CO emission rate shall not exceed a one (1) hour average concentration of 25 ppmvd of CO at 15 percent O_2 in conjunction with firing natural gas at operating loads above 50 percent; and
(b) The CO emission rate shall not exceed a one (1) hour average concentration of 20 ppmvd of CO at 15 percent O_2 in conjunction with firing diesel fuel at operating loads above 50 percent.

(2) Perform good combustion practices.

D.1.5 Volatile Organic Compounds (VOC) - Best Available Control Technology [326 IAC 8-1-6] for the eight (8) combustion turbines

Pursuant to 326 IAC 8-1-6 (General Reduction Requirements; new facilities), the source shall perform good combustion practices.

D.1.6 Particulate Matter (PM/PM_{10}) - Best Available Control Technology [326 IAC 2-2-3] for the eight (8) combustion turbines

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) Natural gas as primary fuel;

(2) Limit diesel fuel as established under the SO_2 BACT analysis; and

(3) Perform good combustion practices.

D.1.7 Non-Criteria PSD Pollutants (Beryllium and H_2SO_4) - Best Available Control Technology [326 IAC 2-2-3] for the eight (8) combustion turbines

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) Use natural gas as the primary fuel for the combustion turbines;

(2) The sulfur content of the diesel fuel used by the combustion turbines shall not exceed 0.05 percent by weight; and

(3) Perform good combustion practices.

D.1.8 Nitrogen Oxides (NOx) - Best Available Control Technology [326 IAC 2-2-3] for the two (2) emergency diesel generators

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall perform good combustion practices as BACT.

D.1.9 Sulfur Dioxide (SO_2) - Best Available Control Technology [326 IAC 2-2-3] for the two (2) emergency diesel generators

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) Perform good combustion practices;

(2) The sulfur content of the diesel fuel used by the generators shall not exceed 0.05 percent by weight; and

(3) The total input of the diesel fuel to the generators shall be limited to 528 gallons per day and shall not exceed a total of 44,000 gallons per twelve consecutive month period, rolled on a monthly basis. This usage limitation is equivalent to 0.40 tons of SO_2 per year and 27.5 tons of NOx per year.

D.1.10 Carbon Monoxide (CO) - Best Available Control Technology [326 IAC 2-2-3] for the two (2) emergency diesel generators

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall perform good combustion practices as BACT.

D.1.11 Particulate Matter (PM/PM_{10}) - Best Available Control Technology [326 IAC 2-2-3] for the two (2) emergency diesel generators

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) The limit of diesel fuel established under the SO_2 BACT analysis; and

(2) Perform good combustion practices.

D.1.12 Best Available Control Technology [326 IAC 2-2-3] for the emergency diesel fire pump

Pursuant to 326 IAC 2-2-3 (PSD - Control Technology Review Requirements), the source shall comply to the following BACT:

(1) Perform good combustion practices;

(2) The sulfur content of the diesel fuel used by the fire pump shall not exceed 0.05 percent by weight; and

(3) The total input of the diesel fuel to the fire pump shall be limited to 2,050 gallons per twelve consecutive month period, rolled on a monthly basis.

D.1.13 40 CFR Part 60, Subpart GG Applicability (Stationary Gas Turbines)

(a) The eight (8) combustion turbines are subject to 40 CFR Part 60, Subpart GG because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

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

(1) limit nitrogen oxides emissions, 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 peck 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.1.14 40 CFR Part 60, Subpart Kb Applicability (Volatile Organic Storage Vessels)

Pursuant to 40 CFR Part 60, Subpart Kb, the Permittee shall notify the Administrator and the Office of Air Management within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. (Available data on the storage temperature may be used to determine the maximum vapor pressure as determined in 40 CFR Part 60.117b(e)(1)-(3)).

D.1.15 New Source Toxics Control (326 IAC 2-1-3.4)

326 IAC 2-1-3.4 (New Source Toxics Rule) is not applicable because single HAP emissions are not greater than or equal to 10 tons per year per turbine and the combination HAPs' emissions are not greater than or equal to 25 tons per year per turbine.

D.1.16 326 IAC 7-1 (Sulfur Dioxide Emission Limitations)

Pursuant to 326 IAC 7-1.1-2, the sulfur dioxide emissions from the eight (8) turbines and the two (2) diesel generators, shall not exceed 0.5 pounds per million Btu for distillate oil combustion.

D.1.17 Carbon Monoxide Emission Limitations [326 IAC 9-1]

This source is subject to 326 IAC 9-1 because it is a stationary source of CO emissions commencing operation after March 21, 1972. There are no applicable CO emission limits, under this state rule, established for this type of operation.

D.1.18 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this facility and its control device.

Compliance Determination Requirements

D.1.19 Testing Requirements

(a) Pursuant to 326 IAC 3-5, the Permittee shall conduct a performance test on the combustion turbines' exhaust stacks (designated as #1-#8) in order to certify the continuous emission monitoring system for NOx and CO.

(b) IDEM may require compliance testing at any specific time when necessary to determine if the source is in compliance. If testing is required by IDEM, compliance with the SO2, NOx and CO limits specified in Condition D.1.2, D.1.3 and Condition D.1.4, shall be determined by a performance test conducted in accordance with Section C - Performance Testing.

D.1.20 326 IAC 7-1 [Sulfur Content Compliance]

(a) Pursuant to 326 IAC 7-2-1, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.5 pounds per million Btus by:

(1) Fuel sampling and analysis data shall be collected pursuant to procedures specified in 326 IAC 3-7-4 for oil combustion and shall be determined by using a calendar month average sulfur dioxide emission rate in pounds per million Btus unless a shorter averaging time or alternate methodology is specified under 326 IAC 7-2. Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling; or

(2) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the eight (8) combustion turbines, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6, or

(3) Upon written notification of a facility owner or operator to the department, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance.

(b) A determination of noncompliance pursuant to either of the methods specified in (1), (2) or (3) above shall not be refuted by evidence of compliance pursuant to the other method.

Compliance Monitoring Requirements

D.1.21 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 daily basis as follows:

(a) Monitor the sulfur content of the natural gas being fired in the turbine by ASTM methods D 1072-80, D 3031-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

(b) Monitor 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 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 custom 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.1.22 Continuous Emission Monitoring System (CEMS) [326 IAC 3-5]

(a) 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 2-1-3(i)(8) 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.

(b) For NOx and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous monitoring system for stacks designated as #1-#8 in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NO_x and CO emissions rates in pounds per hour and parts per million (ppmvd). The use of CEMS to measure and record the NOx and CO hourly limits, is sufficient to demonstrate compliance with the 15 ppm NOx limit and 42 ppm CO limit. To demonstrate compliance with the 12 parts per million NOx annual limit, the source shall average the parts per million over a twelve (12) consecutive month period.

(2) The CEMS shall be in operation at all times when the eight (8) turbines are in operation.

(3) The Permittee shall submit to IDEM, OAM, 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) The Permittee shall follow parametric monitoring requirements for determining SO2 emissions contained in the "*Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units*" in lieu of continue monitoring emissions monitors (CEMS).

(1) Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* protocol.

(2) The Permittee shall apply to IDEM for initial certification to use the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* protocol, no later than 45 days after the compliance of all certification tests.

(3) All certification and compliance methods shall be conducted in accordance with the procedures outlined in 40 CFR Part 75, Appendix D.

Record Keeping and Reporting Requirements [326 IAC 2-1-3]

D.1.23 Record Keeping Requirements

(a) To document compliance with Condition D.1.2, D.1.3, D.1.4, the Permittee shall maintain records of the following:

(1) amount of diesel fuel combusted (in gallons) per turbine during each month;

(2) amount of natural gas combusted (in MMCF) per turbine during each month;

(3) the percent sulfur content of the diesel fuel; and

(4) the heat input capacity of each turbine.

(b) To document compliance with Condition D.1.2 and D.1.4, the Permittee shall record the emission rates of NOx and CO in pounds per hour and parts per million (ppmvd) based on a hourly and monthly average. The source shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(c) To document compliance with Condition D.1.9 and D.1.12, the Permittee shall maintain records of the following:

(1) amount of diesel fuel combusted per unit (in gallons) during each month; and

(2) the percent sulfur content of diesel fuel.

(d) To document compliance with Condition D.1.14, the Permittee shall:

(1) maintain the records of the volatile organic liquid (VOL) stored;

(2) the period of storage;

(3) the maximum true vapor pressure of the volatile organic liquid (VOL) during the respective storage period; and

(4) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

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

D.1.24 Reporting Requirements

(a) The Permittee shall submit a quarterly excess emissions report, if applicable, based on the continuous emissions monitor (CEM) data for NO_x and CO, pursuant to 326 IAC 3-5-7. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with condition C.11 - General Reporting Requirements of this permit.

(b) Pursuant to 326 IAC 7-2-1, owners or operators of sources or facilities subject to 326 IAC 7-1.2 or 326 IAC 7-4, shall submit to the Commissioner the following reports based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-3:

(1) Shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btus upon request.

(c) A quarterly summary of the information to document compliance with Condition D.1.2, D.1.3, D.1.9 and D.1.12 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 MANAGEMENT
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 PARTICULATES ?_____, 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: Vermillion Generating Station PHONE NO. (704)-382-2520

LOCATION: Eugene Township/Vermillion
PERMIT NO. 165-10476 AFS PLANT ID: 165-00022 AFS POINT ID: _________________ INSP: _________________
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON:
____

DATE/TIME MALFUNCTION STARTED: _____/_____/ 19____ ____ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION:____

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE______/______/ 19____ ________________ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO2, VOC, OTHER:_____________________________________
ESTIMATED AMOUNT OF POLLUTANT MITTED 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:__________________

FAX NUMBER - 317 233-5967

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. The requirements of this rule (326 IAC 1-6) shall apply to the owner or operator of any facility which has the potential to emit twenty-five (25) pounds per hour of particulates, one hundred (100) pounds per hour of volatile organic compounds or SO2, or two thousand (2,000) pounds per hour of any other pollutant; or to the owner or operator of any facility with emission control equipment which suffers a malfunction that causes emissions in excess of the applicable limitation.

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. (Air Pollution Control Board; 326 IAC 1-2-39; filed Mar 10, 1988, 1:20 p.m. : 11 IR 2373)

***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 Management
Compliance Data Section

Quarterly Report

Company Name: Duke Energy Vermillion, LLC
Location: CR 300 N and SR 63, Eugene Township, Indiana 47928
Permit No.: 165-10476-00022
Source: Eight (8) combustion turbines
Pollutant: NOx
Limit: 20,336 MMCF per twelve (12) consecutive month period (equivalent to 426.0 tons of NOx per twelve (12) consecutive month period)

Year: ____________

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

9 No deviation occurred in this quarter.

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

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

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

Quarterly Report

Company Name: Duke Energy Vermillion, LLC
Location: CR 300 N and SR 63, Eugene Township, Indiana 47928
Permit No.: 165-10476-00022
Source: Eight (8) combustion turbines
Pollutant: SO_2
Limit: 34,000 kilo-gallons per twelve (12) consecutive month period (equivalent to 116.0 tons of SO_2 per twelve (12) consecutive month period)

Year: ____________

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

9 No deviation occurred in this quarter.

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

Submitted by: ____
Title / Position: ____
Signature: ____
Date: ____
Phone: _______________________________________

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

Quarterly Report

Company Name: Duke Energy Vermillion, LLC
Location: CR 300 N and SR 63, Eugene Township, Indiana 47928
Permit No.: 165-10476-00022
Source: Two (2) emergency diesel generators
Pollutant: SO_2
Limit: 528 gallons per day and 44,000 gallons per twelve (12) consecutive month period

Year: ____________

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

9 No deviation occurred in this quarter.

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

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

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

Quarterly Report

Company Name: Duke Energy Vermillion, LLC
Location: CR 300 N and SR 63, Eugene Township, Indiana 47928
Permit No.: 165-10476-00022
Source: One (1) emergency diesel fire pump
Pollutant: SO_2
Limit: 2,050 gallons per twelve (12) consecutive month period

Year: ____________

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

9 No deviation occurred in this quarter.

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

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

Indiana Department of Environmental Management
Office of Air Management

Technical Support Document (TSD) for New Construction and Operation

Source Background and Description

Source Name:	Vermillion Generating Station
Source Location:	CR 300 N and SR63, Eugene Township, IN 47928
County:	Vermillion
Construction Permit No.:	CP-165-10476-00022
SIC Code:	4911
Permit Reviewer:	Nysa L. James

The Office of Air Management (OAM) has reviewed an application from Duke Energy Vermillion, LLC relating to the construction and operation of a 640 MW merchant power plant, consisting of the following equipment:

(a) Eight (8) simple cycle, natural gas-fired combustion turbines, designated as units #1-#8, with a maximum heat input capacity of 1,272 mmBtu/hr each, a nominal output of 80 MW each, utilizing diesel fuel as a back-up fuel source, controlled by low-NOx combustors in conjunction with natural gas usage, controlled by wet-injection in conjunction with diesel fuel usage and exhausts to stacks designated as #1-#8.

(b) Two (2) Emergency diesel generators, designated as units #9 and #10, with a maximum heat input capacity of 17.21 mmBtu/hr each and exhausts to stacks designated as #9 and #10.

(c) One (1) emergency diesel fire pump, designated as unit #11, with a maximum heat input capacity of 1.6 mmBtu/hr and exhausts to a stack designated as #11.

(d) Four (4) diesel fuel storage tanks, designated as tanks #1-#4, with a maximum capacity of 519, 000 gallons per tank, a maximum volume of 69,400 ft3 per tank and exhausts to vents designated as #12-#15.

Air Pollution Control Justification as Integral Part of the Process

The company has submitted the following justifications such that the low-NOx combustors be considered as an integral part of the turbines:

(a) The combustor is an integral part of the combustion turbines proposed by the source. The combustion section of the unit is where fuel is introduced, ignited and burned. Without the combustor, the turbine could not operate. Based on this information, the low-NOx combustors are considered integral to the turbines.

The OAM has evaluated the justifications and agreed that the low-NOx combustors will be considered as an integral part of the turbines. Therefore, the permitting level will be determined using the potential emissions after the low-NOx combustors. Operating conditions will be specified in the proposed permit that this low-NOx combustors shall operate at all times when the turbines are in operation.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^{0}F)
1-8	Eight (8) turbines	90	14.75	1,648,810	929
9-10	diesel generator	16	0.833	12,530	998
11	diesel fire pump	4	0.416	1,718	985
12-15	diesel fuel storage tanks	general vent	--	--	--

Recommendation

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

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

An application for the purposes of this review was received on December 18, 1998, with additional information received on January 6, 1999, March 4, 1999, March 19, 1999 and April 27, 1999.

Emissions Calculations

See Appendix A (Emissions Calculation Spreadsheets for diesel generators, fire pump and hazardous air pollutants) for detailed calculations (four (4) pages).

Hazardous Air Pollutants (HAPs) emission calculations were submitted by the company. The Office of Air Management has reviewed and verified those emission rates to be valid at this time since there is not a final version of the AP-42 (Section 3.1 Stationary Gas Turbines) emission factors for organic HAPs.

Emissions for the turbines are based on the site area temperature when operating (for natural gas based on 57 ^oF and diesel fuel oil based on -23 ^oF) and worst case operating conditions (information supplied by the General Electric vendor). Compliance shall be demonstrated by use of a continuous monitoring system for CO and NOx. Compliance for SO_2 shall be demonstrated by utilizing 40 CFR Part 75, Appendix D.

<u>Potential To Emit of Eight (8) Combustion Turbines -</u>

NOx potential to emit - Worst case emissions are based using diesel fuel oil (-23 ^oF) at all times
- 196.0 pounds of NOx per hour per turbine (based on diesel fuel oil) *
- 8760 hours per year * ton/2000 pounds = 858.48 tons per year per turbine.
- 858.48 tons per year per turbine * 8 (total number of turbines) = **6867.84 tons per year**.

CO potential to emit - Worst case emissions are based using natural gas at all times.
- 54.0 pounds of CO per hour per turbine (based on natural gas) * 8760
- hours per year * ton/2000 pounds = 236.52 tons per year per turbine.
- 236.52 tons per year per turbine * 8 (total number of turbines) = **1892.16 tons per year**.

SO_2 potential to emit - Worst case emissions are based using diesel fuel oil at all times.
- 58.0 pounds of SO_2 per hour per turbine (based on diesel fuel oil) *
- 8760 hours per year * ton/2000 pounds = 254.04 tons per year per turbine.
- 254.04 tons per year per turbine * 8 (total number of turbines) = **2032.32 tons per year**.

VOC potential to emit - Worst case emissions are based using diesel fuel oil at all times.
- 10.0 pounds of VOC per hour per turbine (based on diesel fuel oil) *
- 8760 hours per year * ton/2000 pounds = 43.8 tons per year per turbine.
- 43.8 tons per year per turbine * 8 (total number of turbines) = **350.4 tons per year**.

PM/PM_{10} potential to emit - Worst case emissions are based using diesel fuel oil at all times.
- 10.0 pounds of PM/PM_{10} per hour per turbine (based on diesel fuel
- oil) * 8760 hours per year * ton/2000 pounds = 43.8 tons per year per turbine.
- 43.8 tons per year per turbine * 8 (total number of turbines) = **350.4 tons per year**.

Limited Potential to Emit of combustion turbines is based on 2500 hours per year (2000 hours in conjunction with natural gas and 500 hours in conjunction with diesel fuel)

NOx - (42.6 pounds per hour * 2000 hours per year * ton/2000 lb) + (196.0 pounds per hour * 500 hours per year * ton/2000 lb) = 91.6 tons per year per turbine
91.6 tons per year per turbine * 8 (total number of turbines) = 732.8 tons per year.

SO2 - (58.0 pounds per hour * 500 hours per year * ton/2000 lb) + 0.6 tons per year (natural gas) = 15.1 tons per year per turbine
15.1 tons per year per turbine * 8 (total number of turbines) = 120.8 tons per year.

CO - (54.0 pounds per hour * 2500 hours per year * ton/2000 lb) = 67.5 tons per year per turbine
67.5 tons per year per turbine * 8 (total number of turbines) = 540.0 tons per year.

VOC - (2.06 pounds per hour * 2000 hours per year * ton/2000 lb) + (10.0 pounds per hour * 500 hours per year * ton/2000 lb) = 4.56 tons per year per turbine
4.56 tons per year per turbine * 8 (total number of turbines) = 36.48 tons per year.

PM/PM_{10} - (5.0 pounds per hour * 2000 hours per year * ton/2000 lb) + (10.0 pounds per hour * 500 hours per year * ton/2000 lb) = 7.5 tons per year per turbine
7.5 tons per year per turbine * 8 (total number of turbines) = 60.0 tons per year.

Total Potential and Allowable Emissions

Indiana Permit Allowable Emissions Definition (after compliance with applicable rules, based on 8,760 hours of operation per year at rated capacity):

Pollutant	Allowable Emissions (tons/year)	Potential Emissions (tons/year)
Particulate Matter (PM)	--	366.2
Particulate Matter (PM10)	--	366.2
Sulfur Dioxide (SO_2)	--	2040.32
Volatile Organic Compounds (VOC)	–	364.6
Carbon Monoxide (CO)	--	2026.26

Nitrogen Oxides (NO_x)	–	7372.64
Acetaldehyde	--	2.52
Acrolein	–	1.53
Antimony	--	0.981
Arsenic	--	0.218
Benzene	--	34.71
Beryllium	--	0.015
Cadmium	--	0.187
Chromium	--	2.10
Cobalt	--	0.406
Formaldehyde	--	72.26
Lead	--	2.59
Manganese	--	10.25
Mercury	--	0.041
Naphthalene	--	5.79
Nickel	--	53.5
POM	–	3.65
Phosphorus	--	13.4
Propylene	--	0.44
Selenium	--	0.236
Toluene	--	12.57
Xylene	--	8.63
Combination of HAPs	–	226.02

(a) Allowable emissions are determined from the applicability of rule 326 IAC 7-1.1-2. Pursuant to 326 IAC 7-1, the sulfur dioxide emissions from the eight (8) turbines shall be limited to 0.5 pounds per million Btu for distillate oil combustion. Compliance shall be determined based on 326 IAC 7-2.

(b) The potential emissions before control are less than the allowable emissions, therefore, the potential emissions before control are used for the permitting determination.

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

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

County Attainment Status

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

Source Status

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

Pollutant	Emissions (ton/yr)
PM	60.94
PM10	60.94
SO_2	121.2
VOC	37.32
CO	547.6
NO_x	761.6
Acetaldehyde	0.719
Acrolein	0.436
Antimony	0.056
Arsenic	0.012
Benzene	8.37
Beryllium	0.0008
Cadmium	0.011
Chromium	0.120
Cobalt	0.023
Formaldehyde	20.62
Lead	0.148
Manganese	0.585
Mercury	0.0023
Naphthalene	0.577
Nickel	3.05
POM	0.209
Phosphorus	0.763
Propylene	0.025
Selenium	0.013
Toluene	2.71
Xylene	0.695
Combination HAPs	39.15

(a) This new source is a major stationary source because at least one regulated attainment pollutant is emitted at a rate of 250 tons per year or greater. This new source is not one of the 28 listed source categories. Therefore, pursuant to 326 IAC 2-2, and 40 CFR 52.21, the PSD requirements apply.

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,
(b) a single hazardous air pollutant (HAP) is greater than or equal to 10 tons per year, or
(c) any combination of HAPs is greater than or equal to 25 tons/year.

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

Federal Rule Applicability

(a) 40 CFR 60, Subpart GG (Stationary Gas Turbines):
The eight (8) combustion turbines are subject to 40 CFR Part 60, Subpart GG because the heat input at peak load is equal to or greater than 10.7 gigajoules 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, 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 peck 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);

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

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

(b) 40 CFR Part 60, Subpart Kb (Volatile Organic Storage Vessels):
Tanks #1-#4 are subject to 40 CFR Part 60, Subpart Kb because the maximum capacity of each is greater than 40 m^3 that is used to store volatile organic liquids (including petroleum) for which construction, reconstruction, or modification commenced after July 23, 1984.

The tanks are exempt from the General Provisions (Part 60, subpart A) and from the provisions of this subpart because the tanks have a capacity greater than or equal to 151 m^3, storing liquid with a maximum true vapor pressure less than 3.5 kPa.

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

(1) maintain the records of the volatile organic liquid (VOL) stored;

(2) the period of storage;

(3) the maximum true vapor pressure of the volatile organic liquid (VOL) during the respective storage period;

(4) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel;

(5) shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. (Available data on the storage temperature may be used to determine the maximum vapor pressure as determined in 40 CFR Part 60.117b(e)(1)-(3))

(c) This source is subject to the requirements of 40 CFR Part 72-80 (Acid Rain Program). The requirements of this program shall be detailed in the Acid Rain, Phase II Permit. The source submitted their Acid Rain, Phase II permit application on March 9, 1999.

(d) There are no other New Source Performance Standards (326 IAC 12) and 40 CFR Part 60 applicable to this facility.

(e) There are no NESHAP 40 CFR Part 63 applicable to this facility.

State Rule Applicability

326 IAC 1-5-2 and 326 IAC 1-5-3 (Emergency Reduction Plans):
Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

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

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

Indiana Department of Environmental Management
Compliance Branch, Office of Air Management
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015
within 180 days from the date on which this source commences operation.

(c) If the ERP is disapproved by IDEM, OAM, 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, OAM, 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, OAM, 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]

The source is subject to 326 IAC 1-5-2 and 1-5-3 because the source's CO, NOx, SO_2 and PM_{10} PTE is greater than 100 tons per year.

326 IAC 1-6-3 (Preventive Maintenance):

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMP) 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 and OAM upon request and shall be subject to review and approval by IDEM and OAM.

326 IAC 1-7 (Stack Height Provisions):

Stacks designated as #1-#8 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 SO2 . 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 2-1-3.4 (New Source Toxics Rule) is not applicable because single HAP emissions are not greater than or equal to 10 tons per year per turbine and the combination HAPs' emissions are not greater than or equal to 25 tons per year per turbine.

326 IAC 2-2 (Prevention of Significant Deterioration):

This new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO2, CO, NOx, Be and H_2SO_4, because the potential to emit for these pollutants exceed the PSD major "significant" thresholds.

Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

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

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

326 IAC 2-6 (Emission Reporting):

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

326 IAC 3-5 (Continuous Monitoring of Emissions):

(a) 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 2-1-3(i)(8) 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.

(b) For NOx and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous monitoring system for stacks designated as #1-#8 in accordance with 326 IAC 3-5-2 and 3-5-3.

1. The continuos emission monitoring system (CEMS) shall measure NO_x and CO emissions rates in pounds per hour and parts per million (ppmvd). The use of CEMS to measure and record the NOx and CO hourly limits, is sufficient to demonstrate compliance. To demonstrate compliance with the 12 ppm of NOx annual limit, the source shall take an average of the parts per million (ppm) over a twelve (12) consecutive month period. The source shall maintain records of the parts per million and the pounds per hour.

2. The Permittee shall submit to IDEM, OAM, 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.

(c) The Permittee shall follow parametric monitoring requirements for determining SO2 emissions contained in the "*Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* in lieu of continue monitoring emissions monitors (CEMS).

1. Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the *“Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units”* protocol.

2. The Permittee shall apply to IDEM for initial certification to use the *“Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units”* protocol, no later than 45 days after the compliance of all certification tests.

3. All certification and compliance methods shall be conducted in accordance with the procedures outlined in 40 CFR Part 75, Appendix D.

4. The source shall maintain records of the sulfur content of the diesel oil, the amount oil combusted per turbine on a monthly basis, and the heat input capacity.

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

326 IAC 5-1-2 (Opacity Limitations):

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

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

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

326 IAC 6-2 does not apply to the turbines because the combustion units are not utilized for indirect heating.

No other 326 IAC 6 rules apply.

326 IAC 7-1 (Sulfur Dioxide Emission Limitations):

Pursuant to 326 IAC 7-1.1-2, the sulfur dioxide emissions from the three (3) turbines shall be limited to 0.5 pounds per million Btu for distillate oil combustion.

326 IAC 7-2-1 (Compliance and Reporting Requirements):

(a) Pursuant to 326 IAC 7-2-1, owners or operators of sources or facilities subject to 326 IAC 7-1.2 or 326 IAC 7-4, shall submit to the Commissioner the following reports based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-3:

    (1) Shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btus upon request.

(b) Pursuant to 326 IAC 7-2-1, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.5 pounds per million Btus by:

(1) Fuel sampling and analysis data shall be collected pursuant to procedures specified in 326 IAC 3-7-4 for oil combustion and shall be determined by using a calendar month average sulfur dioxide emission rate in pounds per million Btus unless a shorter averaging time or alternate methodology is specified under 326 IAC 7-2. Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and
(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling; or

(2) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the three (3) combustion turbines, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6, or

(3) Upon written notification of a facility owner or operator to the department, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance.

A determination of noncompliance pursuant to either of the methods specified in (1), (2) or (3) above shall not be refuted by evidence of compliance pursuant to the other method.

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.

No other 326 IAC 8 rules apply.

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

Air Toxic Emissions

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

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

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

Conclusion

The construction of this merchant power plant will be subject to the conditions of the attached proposed **Construction Permit No. CP-165-10476-00022.**

APPENDIX C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

Source Name:	Vermillion Generating Station
Source Location:	CR 300 N and SR63, Eugene Township, IN 47928
County:	Vermillion
Construction Permit No.:	CP-165-10476-00022
SIC Code:	4911
Permit Reviewer:	Nysa L. James

Bact analyses for PM/PM_{10}, NOx, SO_2, CO, Beryllium (Be) and Sulfuric Acid Mist (H_2SO_4) have been conducted in accordance with US EPA “Top-Down Bact Guidance”. The RACT/BACT/LAER Clearinghouse and related state permits were reviewed for control technology information dated March 15, 1990. These analyses consisted of the following:

1. On-line search of the BACT/LAER Clearinghouse;
2. Permits from other regulatory agencies;
3. Permit engineers;
4. Vendors/suppliers;
5. Inspection & Performance reports; and
6. OAQPS control cost manual and trade journals.

The BACT analyses submitted by Duke Energy, has been evaluated by the Office of Air Management (OAM). OAM agrees with the chosen controls and/or limits. A summary of the BACT analyses are as follows:

(1) Eight (8) simple cycle combustion turbines with a maximum nominal capacity of 80 MW per unit

BACT for NOx -

Summary of Potential NOx Control Technology Options:

1. Catalytic Combustion (“XONON”)
2. SCR (non-ammonia, i.e. “SCONOX”)
3. SNCR
4. SCR (ammonia based)
5. SCR (ammonia based) with Dry Low-NO_x Combustor
6. SCR (ammonia based) with Water/Steam Injection
7. Dry Low-NO_x Combustor
8. Water/Steam Injection
9. Engineering Practices

Technologies considered to be technically infeasible for the control of NOx in combination with a simple cycle combustion turbine:

1. *XONON (Catalytic Combustion)* - This is an emerging “front end” technology which is a catalytic (flameless) combustion technology and is potentially capable of reducing gas turbine’s NOx emissions. This technology uses an oxidation catalyst within the combustor to produce a lower temperature flame and hence, low NOx emissions. The XONON is being sold commercially for certain smaller engine models, but is not being offered for larger turbine models, such as the one’s proposed by the source.

Also, the XONON combustors have not yet been developed for use with liquid fuel, which the source will utilize. Based on the reasons listed above, this technology is considered to be technically infeasible.

2. *SCONOX (SCR without ammonia)* - This is an emerging " back-end" technology similar to selective catalytic reduction which uses a back-end catalyst but it operates without ammonia. This has shown promise on initial trials on a smaller turbine (23 MW) in California, however it can only operate at a maximum temperature of 750 ^{o}F. Larger simple cycle turbines, such as the one's proposed by the source, operate at a much higher temperature (1000 ^{o}F), therefore this control technology is not technically feasible for larger simple cycle units. Region I has concluded that until the scale up design is complete, it is not an available technology. Also, ABB, who will be designing and constructing the scale up, states that the scale up design is a year away or more and then they still have to build and test them. Currently, there are still some concerns about the scale up design.

3. *SNCR* - This is a "back-end" technology which uses ammonia or urea injection similar to SCR but operates at a higher temperature (1600 ^{o}F - 2200 ^{o}F). The reaction occurs without a catalyst, effectively reducing NO_x to nitrogen and water. Since the SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 1100 ^{o}F. Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbine operating flow velocities. This control technology has not be tested on gas turbines as of to date, and therefore, is considered not technically feasible for this project.

Technologies considered to be technically feasible for the control of NO_x in combination with a simple cycle combustion turbine:

1. *SCR* - Selective Catalytic Reduction is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. The SCR technology uses ammonia to reduce NO_x to nitrogen and water in the presence of a catalyst. The reaction occurs on the surface of the catalyst. Technical factors related to this technology include the catalyst reactor design, optimum temperature, sulfur content of the fuel, and the design of ammonia injection system.

2. *SCR with Dry Low-NO_x Combustors* - Combines the SCR technology and the Dry Low-NO_x combustors as described individually in this section. The range of NO_x emissions from this type of combined control is 0.9 ppm - 10 ppm for natural gas and 4.2 ppm - 25 ppm for diesel fuel. The Vermillion Generating Station proposes a reduction to 3.5 ppm @ 15% O_2.

3. *SCR with Water Injection* - Combines the SCR technology and Water Injection as described individually in this section. The range of NO_x emissions from this type of combined control is 2.5 ppm - 10 ppm for natural gas and 4.2 ppm - 25 ppm for diesel fuel.

4. *Dry Low-NO_x Combustors* - This is a lean pre-mixed combustion control which reduces combustion temperatures, thereby reducing thermal NO_x. Fuel formation is not controlled with this technique. A lean pre-mixed design premixes the fuel and air prior to combustion which results in a homogeneous air/fuel mixture.

This mixture minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. The range of NO_x emissions from this type of control is 9 ppm - 25 ppm for natural gas.

5. *Water/Steam Injection* - This is a type of combustion control which injects either water or steam into the combustor and acts as a heat sink to lower localized fuel-rich pockets that produce higher NOx emissions. The range of NOx emissions from this type of control is 25 ppm -75 ppm for natural gas and 42 ppm - 110 ppm for diesel fuel. The range of percent reduction is 70 - 90 percent.

6. *Engineering Practices* - This is a general area consisting of such items as proper combustion and control practices.

<u>BACT Determination:</u>

1. An important factor that affects the performance of the SCR is the operating temperature. Gas turbines that operate in simple cycle have exhaust gas temperatures in the range of 850°F - 1000°F. The common reduction catalyst, such as platinum and base metal, used for this technology require low temperatures (400°F - 800°F) in order for the reaction to occur. Operating above the maximum operating temperature results in oxidation of ammonia to either nitrogen oxides (thereby increasing NO_x) or ammonia nitrate. High temperature zeolite catalysts are available with operating temperatures up to 1100°F, but yield lower NO_x conversion efficiency. Base metal catalysts are most commonly used in SCR applications, accounting for 80% of all U.S. installations, and operate in cogeneration and combined cycle operations.

   As noted above, zeolite catalysts can operate at high exhaust temperatures which is suitable for simple cycle units. Based on contacts with two (2) principal vendors of zeolite catalysts ,as well as a review of the RACT/BACT/LAER Clearinghouse, there are only four (4) simple-cycle combustion turbine installations in the United States that are presently in operation with high temperature SCR catalysts. One (1) installation is at a natural gas pipeline compressor station in Southern California on three (3), four (4) MW turbines, which are much smaller than the proposed project. This facility experienced significant operational problems with the original system and applied to the local Air Board for permission to remove the SCR systems.

   The second installation is at a municipal utility peaking station in Northern California. There are three (3) turbines at this site with high temperature zeolite catalysts; these three (3) turbines are 20, 20 and 26 MW, respectively. This also is much smaller than the proposed project. These units have very limited operating time since installation, less than 500 hours per unit and at this time, no operational data is available.

   The third installation is the Carson Icegen facility located outside of Sacramento California. This site consists of one (1) turbine, a GE LM 6000 model, rated at 42 MW and is limited to 5 ppmvd NO_x at 15 percent O_2.   Ammonia slip is limited to 10 ppmvd when burning gas and 20 ppmvd when burning digester gas. After speaking with Mr. Jeff White, Carson's plant manager, it was determined that the exhaust temperature on the turbines is around 850 °F, allowing for the use of a tungsten-based catalyst. This installation is also much smaller than the proposed project and in conjunction with the lower exhaust temperatures, is not considered to be representative to this project.

The fourth installation is the Puerto Rico Electric Power Authority facility located in Camblanche, Puerto Rico. This site is equipped with three (3) ABB GT11N turbines firing distillate oil and using SCR as control. This facility uses a high-temperature Englehard zeolite-based catalyst on three (3) 83 MW turbines operating simple cycle. These units have been operating since mid-1997 and are currently in negotiations with EPA over their ability to consistently meet the 10 ppm NO_x outlet emission rate. The emission limits are 10 ppm outlet NO_x and 10 ppm for the ammonia slip associated with the SCR. Finally, an important aspect of the PREPA installation is the incorporation of dilution air into the turbine exhaust prior to the catalyst to maintain the SCR operating temperature below 1, 000 ^oF. Based upon information, no zeolite catalyst SCR systems have been successfully operating on a continual basis for large simple-cycle peaking turbines.

Based upon the U.S. EPA Air Pollution Training Institute (APTI) course T-002-99 - NO_x Control Technology, date January 27, 1999, cites the following five (5) potential issues and concerns with the use of SCR systems.

1. Ammonia Slip- Ammonia slip of 10 ppm results in potential ammonia emissions of seventeen (17) tons per year per turbine.

2. The reaction is temperature dependent. The ideal temperature range is 600 ^oF to 800 ^oF. Above 800 ^oF, the ammonia oxidizes to NO_X. (As states above, the project's exhausts temperature will range from 946 ^oF to 1,029 ^oF. Higher exhaust temperatures will result in increases emissions of both NOx and unreacted ammonia.)

3. Above 800 ^oF, catalyst sintering could occur.

4. Disposal of spent catalysts (hazardous waste).

5. If sulfur fuels are used, sulfates could precipitate out.

The SCR process is also subject to catalyst deactivation over time through either physical decay or chemical poisoning. Physical deactivation is generally the result of either prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or internal contaminants. Chemical poisoning is caused by irreversible reaction of the catalyst with a contaminant in the gas stream and is a permanent condition. Catalysts suppliers typically only guarantee a 3-year lifetime for very low emission level, high performance catalyst systems.

SCR manufacturers estimate 20 parts per million (ppm) or more of unreacted ammonia emissions (ammonia slip) when operating at very high levels. The ammonia injected into the SCR in excess of stoichiometric amounts to achieve maximum conversion of NO_x. Although this reduces NO_x emissions substantially, a significant quantity of ammonia is not reacted, passes through the SCR reactor and is exhausted to the atmosphere. Thus, there is a clear emissions trade-off between NO_x and ammonia NO_x reduction applications of SCR.

The major technical concerns involve the matching of simple-cycle turbine's exhaust gas temperature with acceptable operating temperatures of commercially available catalysts, catalyst fouling when firing diesel fuel, and damage to the catalyst system due to cyclic fatigue, associated with frequent turbine start-ups and shutdowns.

Cooling of the exhaust to bring the temperature within the optimum operating temperature for SCR would further increase the cost to control. Cooling of the exhaust would require either a heat exchanger or the addition of ambient cooling air. Introduction of the cooling air is the least costly of these two (2) alternatives. A cooling air injection system would result in an additional capital expenditure as well as the need to increase the size of the SCR system, and consequently the cost, due to the increased air flow. Dilution of the inlet NO_x concentration may also adversely affect the control efficiency of the SCR. All of these factors will increase the average cost effectiveness above the already excessive estimated average cost effectiveness.

Firing of diesel fuel and other sulfur-bearing fuels produce SO_2 which may oxidize to sulfite in the catalyst reactor. This sulfite reacts with ammonia in the exhaust to also form ammonia salts, resulting in an increase in particulate matter emissions. The sulfite can also form H_2SO_4 in the exhaust stream in direct proportional reflation to the amount of NO_x reduced. Therefore, SCR used on a simple cycle unit, will increase emissions of other pollutants.

Costs to control for an SCR system were estimated using standard EPA procedures. The cost of the SCR technology was calculated using methodology presented in the Office of Air Quality Planning and Standards (OAQPS) Alternative Control Techniques Document - NO_x Emissions From Stationary Turbines (U.S. EPA, 1993). SCR control costs were estimated for a single turbine. NO_x emissions, in combination with low-NO_X combustors, were reduced from 15 ppmvd to 3.5 ppmvd during gas and from 42 ppmvd to 9 ppmvd during oil. Since the Dry Low-NOx combustors are considered to "inherently lower polluting processes", based on the USEPA New Source Review Workshop Manual, baseline emissions shall be the emissions from the lower polluting process. The reduction, in conjunction with the operating hour restrictions, would reduce the emissions from one unit by 78.8 tons per year. The total annual average cost of the SCR is \$19,309 per ton of NO_x removed. The total annual average cost of the SCR and the heat exchanger is \$64,500 per ton NO_x removed.

Therefore, based upon the absence of technological demonstration of SCR on large simple cycle turbines and continual compliance with SCR's NO_x emissions in parts per million, the increase in emissions from ammonia and other referenced pollutants, the cost of the control, SCR shall be eliminated from further consideration in this BACT analysis.

2. Water/Steam injection and Low-NO_x combustors are common technologies viable for most turbines. The Dry Low-NO_x combustors proposed by this source will achieve NO_x emissions levels of 15 ppmvd at 15% O_2 in conjunction with firing natural gas. However, diesel fuel cannot be premixed with air as easily as natural gas. For this reason, the source proposes water injection with NO_x emission levels of 42 ppmvd at 15% O_2 in conjunction with firing diesel fuel. The environmental impacts of using with either above mentioned technologies are insignificant in this case. However, in other cases, increases in the water/fuel ration to above 0.8 can increase CO and HC emissions.

   Dry Low-NO_x combustors can achieve a low-end emission rate of 9 ppmvd. Air Liquide America Corporation has recently received a permit from the Louisiana Department of Environmental Quality which allows their proposed turbine to emit up to 9 ppmvd NO_x at 15 percent O_2 over the 8760 hours of expected annual operation on natural gas fuel. Additionally, compliance with this limit has been demonstrated by conducting three (3) one (1)-hour stack test runs under optimal conditions.

Continuous NO_x monitoring is not being conducted on these base-load units. Under extreme ambient temperatures, NO_x emissions can fluctuate considerably, thereby making a 9 ppmvd NO_x emission level hard to maintain without back end controls. The 9 ppmvd vendor commercial "guarantee" is set for a specific ambient conditions and operational conditions. In the case of the Vermillion Generating Station, the specific temperature is 5~~7~~**3** ^{o}F, the average temperature of Indiana. Any extreme fluctuations in temperature above or below this state average temperature or in operations that will require frequent start-ups and shut downs, will cause fluctuations in the parts per million. There also is a very limited operating history for turbines with combustors that have NO_x emission levels of 9 ppmvd. The high costs of maintenance, limitation of operational flexibility, and the limited history of this type of combustor shall eliminate this level of NO_x emissions from further BACT analysis.

There are two (2) other simple cycle peaking plants using DLN combustors that may achieve emissions lower than what is proposed by this project. They are Deerhaven Power located in Florida and Fort St. Vrain located in Colorado. Based on quarterly EDRs of the two (2) plants for 1998, the average days over 9 ppm is 89 days (70 days for Deerhaven and 103 days for Fort St. Vrain).

Florida Power Corporation was issued a PSD permit on February 25, 1994, for two (2) combustion simple cycle turbines with a nominal output of 261 MW and a NO_x emission limit of 12 ppmvd. At the time of this review, the source has demonstrated compliance with such limit.

The costs of the control technologies proposed by the source, are relatively low and are in a range very similar to one another. The average cost of such controls is $1,545 per ton NO_x removed. The cost analysis submitted by the source is based on 2500 hours of operation per year with diesel fuel limited to 500 hours per year.

The BACT for NO_x is as follows:

1. Use of Dry Low-NO_x combustors in conjunction with natural gas;
2. Use of Wet-Injection in conjunction with diesel fuel;
3. When burning natural gas, the NO_x emission rate shall not exceed a one (1) hour average concentration of 15 ppmvd of NO_x at 15 percent O_2 in conjunction with dry low-NO_x combustors;
4. When burning natural gas, the NO_x emission rate shall not exceed 12 ppmvd of NO_x per year based over twelve (12) consecutive months of operation at 15 percent O_2 in conjunction with dry low-NO_x.
5. When burning diesel fuel, the NO_x emission rate shall not exceed a one (1) hour average concentration of 42 ppmvd of NO_x at 15 percent O_2 in conjunction with wet-injection;
6. The total input of the natural gas fuel to the eight (8) combustion turbines shall be limited to 20,336 MMCF per twelve consecutive month period, rolled on a monthly basis. This usage limitation is equivalent to 426.0 tons of NO_x per year. If diesel fuel oil is combusted during any portion of a twelve (12) consecutive month period, natural gas usage shall be reduced such that NO_x emissions for the eight (8) turbines do not exceed 732.8 tons per year for gas and oil firing combined, as determined by CEMS.

BACT for SO_2 -

Summary for Potential SO_2 Control Technology Options:

1. Flue Gas Desulfurization Systems
2. Use of low sulfur fuels
3. Utilizing natural gas as primary fuel in conjunction with a SO_2 limit

Technologies considered to be technically feasible for the control of SO_2 in combination with a simple cycle combustion turbine:

1. *Flue Gas Desulfurization Systems (FGD)* - This is a technology used to control SO_2 emitted from various combustion sources. A FGD system could be comprised of either a spray dryer which uses lime as a reagent followed by a particulate control device (baghouse or ESP) or a wet scrubber which uses lime as a reagent.

2. The use of the fuels proposed to burn in this project, have established records of compliance when used in combustion equipment such as high efficiency combustion turbines and boilers. The NSPS established maximum allowable SO_2 emissions associated with combustion turbines and requires either an SO_2 emission limitation of 150 ppmvd at 15 percent O_2 or a maximum fuel content of 0.8 percent by weight.

<u>BACT Determination:</u>

1. FGD's installation is principally on coal-fired and high sulfur oil-fired steam-electric generating stations. FGD systems have not been installed on simple cycle peaking combustion units because of the technical and cost factors associated with treating large volumes of high temperature gas containing relatively low levels of SO_2. FGD systems typically operate at an inlet temperature of approximately 400 to 500^{o}F. The exhaust from the proposed turbines is about 1000^oF. Therefore, the high volume, high temperature flue gas would have to be conditioned prior to treatment, significantly increasing the cost of the control system. At the time of this review, the above-mentioned procedure had not been performed. In addition, FGD systems are not typically effective for streams with low SO_2 concentrations such as the flue gas stream from the proposed turbines. 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 lower inlet concentrations of SO_2. In addition, the concentration of SO_2 in the flue gas for the proposed turbines is estimated to be 10 ppmvd, which is comparable to typical outlet concentrations from FDG systems for those installed on coal-fired and other high sulfur oil-fired combustion units.

   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 (e.g., bulk materials handling, wastewater discharges, and solid waste management) due to the disposal of the spent reagent and high water use required for a wet scrubbing system.

   For the technical reason, energy and environmental impacts presented above, FGD systems are excluded from further consideration in this BACT analysis.

2. The source proposed the use of diesel fuel with a sulfur content of 0.05 percent by weight.

The BACT for SO_2 is as follows:

1. Use of natural gas as the primary fuel for the combustion turbines;
2. The sulfur content of the diesel fuel used by the combustion turbines shall not exceed 0.05 percent by weight; and
3. Shall use only diesel fuel oil as a back-up fuel source. The source shall take a total gallons per year limit on the diesel fuel.

   The total input of the diesel fuel to the eight (8) combustion turbines shall be limited to 34,000 kilo-gallons per twelve consecutive month period, rolled on a monthly basis. This usage limitation is equivalent to 116.0 tons of SO_2 per year and 392.0 tons of NOx per year.

BACT for CO -

Summary for Potential CO Control Technology Options:

1. Catalytic Oxidation System
2. Efficient Combustion Control

Technologies considered to be technically feasible for the control of CO in combination with a simple cycle combustion turbine:

1. *Catalytic Oxidation System* - This system is a passive reactor which consists of a honeycomb grid of metal panels coated with platinum catalyst. The catalyst grid is placed in the engine exhaust where the optimum reaction temperature can be maintained at greater than 500 of. In these systems, typically 80-90 percent of the CO is oxidized to CO_2. In addition, the catalyst reduces VOC emissions by 50 percent.

2. *Combustion Control* - The type of combustion control was previously addressed under the BACT for NOx.

<u>BACT Determination:</u>

1. An economic analysis was conducted for the catalytic oxidation system to control CO. The cost for an appropriate CO control system for these types of peaking stations was estimated using an equipment quote from a vendor. The cost includes both the capital cost of the oxidation system and the costs of the operating system. The operating costs include the cost of performance loss because of the pressure drop over the catalyst bed and costs associated with replacement of the catalyst. Because these units will also be combusting diesel fuel, more frequent catalyst replacement will be required.

   The economic feasibility was conducted based upon 90 percent control of the potential to emit of CO emissions from each unit. The costs were based on a single unit as the CO catalyst system would be identical for each unit and, therefore, the cost per ton controlled for a single unit would be identical to the costs per ton for all eight units. Based upon this analysis, CO reduction via the catalytic system would cost $8,977 per ton of CO removed.

Along with this cost, there are significant environmental impacts associated with the use of a catalytic oxidation system. Catalyst vendors predict up to 50 percent conversion of SO_2 to SO_3 at the catalyst operating temperature. The SO_3 then reacts with water to form sulfuric acid or other by-products, which are emitted in the exhaust gas stream. In addition, there is significant concern regarding the disposal of the spent catalyst which would need to be managed as hazardous waste.

Catalytic oxidation add-on control technology is excluded from further BACT consideration due to the environmental impacts associated with the a catalyst, sulfuric acid mist emissions, energy requirements due to the pressure drop over the catalyst bed, and the high cost associated with the control.

2. The combustion proposed for installation at the new source incorporates an efficient combustor design to minimize the CO emissions. The advanced dry low-NOx combustors of the turbines maintain low CO emission rates at operating loads above 50 percent unlike other combustion units which typically have increased CO emissions below 70 percent load.

The BACT for CO is as follows:

1. Combustion control maintaining the following emission limits:
   (a) The CO emission rate shall not exceed a one (1) hour average concentration of 25 ppmvd of CO at 15 percent O_2 in conjunction with firing natural gas at operating loads above 50 percent; and
   (b) The CO emission rate shall not exceed a one (1) hour average concentration of 20 ppmvd of CO at 15 percent O_2 in conjunction with firing diesel fuel at operating loads above 50 percent.
2. Good combustion practices.

BACT for PM/PM_{10} -

Natural gas and diesel fuel are considered to be clean burning fuels. Such fuels are required for combustion turbines in order to prevent damage to the turbine blades and other high-precision turbine components. The installation of a particulate control device is considered impractical because natural gas contains essentially no inert solids (ash) and diesel fuel oil contains only a trace amount of ash.

Given the high combustion efficiency of the turbines and the firing of clean fuels, the PM/PM_{10} emissions will be very low.

The BACT for PM/PM_{10} is as follows:

1. The use of natural gas as primary fuel;
2. The limit of diesel fuel established under the SO_2 BACT analysis ; and
3. Good combustion practices.

BACT for NON-Criteria PSD Pollutants -

Two of the PSD regulated pollutants (Beryllium (Be) and Sulfuric Acid Mist (H_2SO_4)) will be emitted in significant quantities as defined under 326 IAC 2-2 and 40 CFR 52.21. Metal content is related to ash content in the fuels. Coal and residual oil have high ash and metal content whereas distillate fuel oil has extremely low ash and metal content.

Beryllium is not expected to be present in natural gas. Sulfuric acid mist and beryllium would exist in the combustion of diesel fuel oil and would be emitted as particulate matter.

The BACT for Other Pollutants:

1. Use of natural gas as the primary fuel for the combustion turbines;
2. The sulfur content of the diesel fuel used by the combustion turbines shall not exceed 0.05 percent by weight; and
3. Good combustion practices.

(2) Two (2) Emergency diesel-fired generators with a heat input capacity of 17.21 mmBtu/hr each

The two (2) emergency generators shall not exceed 500 hours per year. To ensure compliance with the restricted hours of operation, the input of diesel fuel shall be limited. The emissions from this limitation are 27.5 tons per year for NOx, 7.3 tons per year for CO, 0.4 tons per year for SO_2, 0.9 tons per year for PM/PM_{10} and 0.8 tons per year for VOC.

BACT for NOx -

The NOx control technologies for the diesel generators is the same as what was listed and described in the NOx BACT for the turbines. Control measures for this type of generator is primarily directed at limiting NOx and CO emissions.

The total annual incremental cost of the SCR is $110,459 per ton of NO_X removed. This cost value is based on limited diesel fuel usage rate (based on 500 hours per year). Based on this cost, the SCR is not considered cost effective for the emergency diesel engines.

According to EPA's draft Alternative Control Technology document for reciprocating engines (EPA, 1996), lists back-end control techniques, such as SCR and NSCR, along with combustion techniques, such as ignition retard for NOx control from diesel engines. The ACT concludes that add-on controls are not cost effective for this type of engine.

The NOx BACT for the two (2) emergency diesel-fired engines shall be the following:

1. Good combustion practices.

BACT for SO_2 -

The SO_2 control technologies for the diesel generators is the same as what was listed and described in the SO_2 BACT for the turbines. Control measures for this type of engine is primarily directed at limiting NOx and CO emissions.

The SO_2 BACT for the two (2) emergency diesel-fired engines shall be the following:

1. Good combustion practices; and
2. The sulfur content of the diesel fuel used by the generators shall not exceed 0.05 percent by weight.
3. The total input of the diesel fuel to the generators shall be limited to 528 gallons per day and shall not exceed a total of 44,000 gallons per twelve consecutive month period, rolled on a monthly basis.

This usage limitation is equivalent to 0.4 tons of SO_2 per year and 27.5 tons of NOx per year.

BACT for CO -

Add on control technology is not available for the control of CO emissions from diesel engines which operate less than 500 hours per year. Therefore, the BACT for CO for the two (2) emergency diesel-fired generators is good combustion control practices.

BACT for PM/PM_{10}

Diesel fuel is considered to be a clean burning fuel. Given the limited diesel fuel usage of the generators and the firing of a clean fuel, the PM/PM_{10} emissions will be very low. The installation of a particulate control device is considered impractical because the limited PM/PM_{10} emissions are low.

(3) One (1) emergency diesel-fired water pump with a heat input capacity of 1.61 mmBtu/hr

The emergency fire pump shall not exceed 500 hours per year. To ensure compliance with the restricted hours of operation, the input of diesel fuel shall be limited. The emissions from this limitation are 1.28 tons per year for NOx, 0.34 tons per year for CO, 0.16 tons per year for SO_2 and 0.04 tons per year for PM/PM_{10}.

The BACT for this unit is the same as the BACT for the emergency diesel generators. The BACT is as follows:

1. Good combustion practices; and
2. The sulfur content of the diesel fuel used by the fire pump shall not exceed 0.05 percent by weight.
3. The input of the diesel fuel to the fire pump shall be limited to 2,050 gallons per twelve consecutive month period, rolled on a monthly basis.

TURBINE BACT Summary

Pollutant	BACT for natural gas firing	BACT for diesel fuel firing
NOx	**Dry low-NOx burners, 15 ppmvd per hour @15% O_2, 12 ppmvd per year @ 15% O_2, 91.6 tons per year per turbine (includes 2000 hours for natural gas and 500 hours for diesel fuel)**	**Low-NO_X burners with water injection, 42 ppmvd @ 15% O_2 (limited emissions included as stated prior)**
SO2	**Emissions from the use of natural gas is negligible**	**Use of natural gas as primary, 0.05% sulfur content by weight, limit of 4,250 kilo-gallon per year per turbine**
CO	**Good combustion practices, 25 ppmvd @ 15% O_2**	**Good combustion practices, 20 ppmvd @ 15% O_2**
VOC	**Good combustion practices**	**Good combustion practices**

PM/PM_{10}	**Use of natural gas as primary fuel, good combustion practices and limit on diesel fuel usage as established under SO_2 BACT**	**Use of natural gas as primary fuel, good combustion practices and limit on diesel fuel usage as established under SO_2 BACT**
Other Pollutants	**0.05% sulfur content by weight, good combustion practices, use of natural gas as primary fuel**	**0.05% sulfur content by weight, good combustion practices, use of natural gas as primary fuel**

Air Quality Analysis

Introduction

Duke Energy Vermillion, LLC (Duke Energy) has applied for a Prevention of Significant Deterioration (PSD) permit to construct and operate a new merchant power facility near Cayuga, Vermillion County, Indiana. The site is located at Universal Transverse Mercator (UTM) coordinates 461830.4 East and 4419067.9 North. The proposed merchant power facility will consist of eight high-efficiency combustion turbines, rated at 80 megawatts (MW) each, two 1.5 MW emergency diesel generators and one 140 kilowatt (kW) emergency fire pump. Vermillion County is designated as attainment for all criteria pollutants with a portion of southern Vermillion County redesignated as a maintenance area for Particulate Matter less than 10 microns (PM_{10}).

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

A. Establish which pollutants require an air quality analysis.
B. Determine the significant ambient air impact area 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 qualitative analysis of the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park which is 310 kilometers from the proposed power facility site in Vermillion County, Indiana.

Earth Tech Inc. prepared the PSD permit application for Duke Energy Vermillion, LLC. The permit application was received by the Office of Air Management (OAM) on December 18, 1998 with additional modeling submitted on January 6th and March 12th 1999. This document provides the Air Quality Modeling Section's review of the PSD permit application including an air quality analysis performed by the OAM.

Executive Summary

Duke Energy Vermillion, LLC has applied for a PSD construction permit to construct and operate a merchant power facility southeast of Cayuga in Vermillion County, Indiana. The PSD application was prepared by Earth Tech, Inc. of Concord, Massachusetts. Vermillion County is currently designated as attainment for all criteria pollutants. A portion of Clinton township in Vermillion County (approximately 28 kilometers or 18 miles to the south) is redesignated as a maintenance area for Particulate Matter less than 10 microns (PM_{10}). Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Carbon Monoxide (CO) Sulfuric Acid Mist (H_2SO_4) and PM_{10} emission rates associated with the proposed merchant power facility exceeded their respective significant emission rates. Modeling results taken from the ISCST3 and ISCLT3 models showed all pollutants impacts were predicted to be less than the significant impact increment. OAM conducted Hazardous Air Pollutant (HAPs) modeling and no HAP exceeded 0.5% of its Permissible Exposure Limit (PEL). There was no significant impact on the nearest Class I area, which is Mammoth Cave National Park in Kentucky. Additional impact analysis showed no significant impact on economic growth, soils, vegetation or visibility in the areas surrounding the proposed plant.

Part A

Pollutants Analyzed for Air Quality Impact

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 major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1. CO, NO_2, SO_2, VOC (ozone) and PM_{10} will be emitted from the proposed merchant power facility and an air quality analysis is required for CO, NO_2, SO_2 and PM_{10} which exceeded their significant emission rates as shown in Table 1:

TABLE 1 - Significant Emission Rates (tons/yr)		
Pollutant	**Emission Rate**	**Significant Emission Rate**
CO	549.6	100.0
NO_2	847.5	40.0
SO_2	124.5	40.0
PM_{10}	62.9	15.0
VOC	39.3	40.0
Lead	0.17	0.6
Mercury	0.003	0.1
Beryllium	0.0009	0.004
Sulfuric Acid Mist (H_2SO_4)	12.2	7.0

Part B

Significant Impact Analysis

An air quality analysis was performed to determine the significant ambient air impact area of the source's emissions. A worst-case approach has been taken due to the nature of the project's operational capability. Normal operating loads of 50 percent, 75 percent and 100 percent at 3 ambient temperatures of -23^o F, 53^o F and 104^o F for both natural gas and diesel-fuel firings were modeled to determine worst-case concentrations. Long-term worst-case determination was based on 2000 hours of operation using natural gas firing and 500 hours of diesel fuel firing per year. Emission rates and modeling results for each worst-case determination can be found in Appendix B. Short-term worst-case determinations for each pollutant are summarized below:

TABLE 2 - Summary of Worst-Case Determinations				
Pollutant	**Time-Averaging Period**	**Fuel Type**	**Percent Load**	**Temperature (F)**
CO	1-hour	Natural Gas	100 %	104^o F
CO	8-hour	Natural Gas	75 %	104^o F
SO_2	3-hour	Diesel Fuel	75 %	104^o F

SO_2	24-hour	Diesel Fuel	75 %	104^o F
PM_{10}	24-hour	Diesel Fuel	50 %	104^o F

Maximum modeled concentrations for each pollutant over its significant emission rate are listed below in Table 3 and are compared to each pollutant's significant impact increments for Class II areas. Short-term impacts for 1-hour, 3-hour and 8-hour time-averaging periods include modeled emissions from the two emergency 'black-start' generators and the fire-water pump. These units have daily limits which restrict their operations to less than 12 hours per day.

TABLE 3 - Significant Impact Analysis from Duke Energy (ug/m3)

Pollutant	**Year**	**Time-Averaging Period**	**Modeled Source Impacts**	**Significant Impact Increments**
CO	1990	1-hour	55.6	2000.0
CO	1988	8-hour	22.1	500.0
NO_2	1988	Annual	0.15	1.0
SO_2	1987	3-hour	17.2	25.0
SO_2	1987	24-hour	3.9	5.0
SO_2	1988	Annual	0.02	1.0
PM_{10}	1987	24-hour	1.4	5.0
PM_{10}	1988	Annual	0.02	1.0
VOC (ozone)	1991	1-hour	0.8	3.0
H_2SO_4 mist	1991	8-hour	0.36	1000.0 [a]

[a] OSHA PEL for 8-hour exposure

The northern most portion of the PM_{10} maintenance area in Clinton Township in southern Vermillion county was modeled to determine PM_{10} impacts from Duke Energy. Modeled results showed impacts will not significantly impact this area. Maximum 24-hour modeled impacts were 0.25 ug/m3 and annual modeled impacts were 0.002 ug/m3. No further review was necessary.

Part C

Analysis of Source Impact

The Office of Air Management modeling used the Industrial Source Complex Short Term (ISCST3) model, Version 3, dated 98356 to determine significant impacts. This version utilizes the Schulman-Scire algorithm to account for building downwash effects. Stacks associated with the proposed merchant power facility are below Good Engineering Practice (GEP) stack heights. The aerodynamic downwash parameters were calculated using EPA's Building Profile Input Program (BPIP). OAM used the Industrial Source Complex Long Term (ISCLT3) model, Version 3, dated 97363 as per EPA guidance for NO_2 emissions to compare with Duke Energy's ISCST3 results to determine maximum significant impact increment for NO_2. Results from the NO_2 comparison modeling (see Appendix A) showed the ISCST3 calculated higher concentrations and will be used in the analysis.

The meteorological data used in the ISCST3 model consisted of surface data from the Indianapolis Airport National Weather Service station merged with the mixing heights from Peoria, Illinois Airport National Weather Service Station for the five-year period (1987-1991). Meteorological data was obtained from the EPA Support Center for Regulatory Air Model electronic Bulletin Board and processed by PCRAMMET. The ISCLT3 data consists of joint frequencies of six wind speeds, sixteen wind directions and six stability categories compiled into a meteorological file. Average surface temperatures and mixing heights were determined from the Indianapolis Airport National Weather Service station and were included in the NO_2 input files. OAM modeling utilized receptor grids out to 30 kilometers for PM_{10} and SO_2. Discrete receptors were placed 100 meters apart on Duke Energy's property lines. Modeling performed used the emission rates listed in Table 4-2 of the modeling protocol portion of the application.

EPA issued a new NAAQS for Particulate Matter less than 2.5 microns ($PM_{2.5}$) on July 17, 1997. There are 3 primary origins of $PM_{2.5}$: 1)primary particulates in the solid state, 2)condensable particulates and 3)secondary particulates formed through atmospheric reactions of gaseous precursor emissions. There will be a five-year scientific review of this standard which includes installation of $PM_{2.5}$ monitors throughout the state to better define background concentrations and gather source specific information. EPA is expected to release a new dispersion model in the future to better predict $PM_{2.5}$ concentrations. There are no assumed ratio of $PM_{2.5}$ to PM_{10} at this time. As more information becomes available, a more detailed analysis of $PM_{2.5}$ can be conducted.

<u>Part D</u>

Ozone Impact Analysis

On July 17, 1997, the U.S. EPA promulgated a new NAAQS for ozone. The new standard is 0.08 parts per million, based on an 8-hour averaging time. At the current time, there are no adequate modeling tools available to evaluate ozone impacts from a single source over an 8-hour period. IDEM-OAM is awaiting EPA guidance concerning this 8-hour modeling issue and will continue to model 1-hour ozone concentrations at this time.

Wind rose analysis indicates that prevailing winds in the area would occur from the southwest and west-southwest during the summer months of May through September when ozone formation is most likely to occur. Ozone impacts from Duke's proposed facility would likely fall northeast and east northeast of the facility.

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. However, the lack of supporting documentation and availability of meteorological data and ambient background concentrations makes this methodology extremely difficult to utilize and results can be suspect. The model is unable to accurately predict 8-hour averages or simulate all meteorological and chemistry conditions present during an ozone episode. NAAQS modeling for 1 hour ozone concentrations were conducted to compare the results to the ozone NAAQS limit of 120.0 ppb. The maximum cell concentration for each time and distance specified was used to compare to the ambient mode. OAM modeling results are shown in Appendix C. The impact (difference between the plume-injected and ambient modes) from Duke Energy was 0.8 ppb. All ambient plus plume-injected modes were below the NAAQS limit for ozone at every time period and every distance. No modeled 1-hour NAAQS violations occurred.

Part E

Hazardous Air Pollutant Analysis and Results

OAM presently requests data concerning the emission of 189 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 Management'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. While HAPs emissions after controls were 17.0 tons/yr, the HAPs modeling analysis was conducted at emission rates before controls, which were significantly greater.

TABLE 4 - HAPS Analysis

Hazardous Air Pollutants	Total HAP Emissions	HAP Concentrations	PEL	Percent of PEL
	(tons/year)	(ug/m3)	(ug/m3)	(%)
Acetaldehyde	2.45e+00	2.30e-02	3.60e+05	6.39e-06
Acrolein	1.40e+00	1.30e-02	2.50e+02	5.20e-03
Antimony	1.05e+00	1.00e-02	5.00e+02	2.00e-03
Arsenic	2.10e-01	2.00e-03	1.00e+01	2.00e-02
Benzene	3.47e+01	3.27e-01	3.20e+03	1.02e-02
Beryllium	1.40e-02	2.60e-04	2.00e+00	1.30e-02
Cadmium	1.80e-01	1.60e-03	5.00e+00	3.20e-02
Chromium	2.10e+00	2.00e-02	5.00e+02	4.00e-03
Cobalt	4.21e-01	4.00e-03	1.00e+02	4.00e-03
Formaldehyde	8.84e+01	8.30e-01	9.30e+02	8.92e-02
Lead	2.45e+00	2.10e-02	5.00e+01	2.13e-01
Manganese	1.51e+01	1.42e-01	5.00e+03	2.84e-03
Mercury	4.21e-02	5.00e-04	1.00e+02	5.00e-04
Naphthalene	5.96e+00	5.60e-02	5.00e+04	1.12e-04
Nickel	5.37e+01	5.06e-01	1.00e+03	5.06e-02
Phosphorus	1.33e+01	1.26e-01	1.00e+02	1.26e-01
POM	3.51e+00	3.30e-02	—-- [a]	---
Selenium	2.45e-01	2.40e-03	2.00e+02	1.20e-03
Toluene	1.26e+01	1.20e-01	7.50e+05	1.60e-05
Xylene	8.77e+00	8.30e-02	4.35e+05	1.91e-05

[a] No existing PEL

OAM 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's Permissible Exposure Limit (PEL). The PELs were established by the Occupational Safety and Health Administration (OSHA). In Table 4 above, 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.

Part F

Additional Impact Analysis

The Duke Energy PSD permit application provided an additional impact analysis performed by Earth Tech. This analysis included an impact on economic growth, soils, vegetation and visibility. A construction workforce of 200 is expected and Duke Energy will employ 15 people selected from the local and regional area once the facility is operational. Industrial and residential growth is predicted to have negligible impact in the area since it will be dispersed over a large area and new home construction is not expected to significantly increase. Commercial growth, as a result of the proposed merchant power facility, will occur at a gradual rate and will be accounted for in the background concentration measurements from air quality monitors. A minimal number of support facilities will be needed. There will be no adverse impact on air quality in the area due to industrial, residential or commercial growth.

According to the modeled concentrations for the criteria pollutants CO, NO_2, SO_2 and PM_{10}, there are no soils which might be adversely affected by the proposed merchant power facility. Additionally, the maximum modeled concentrations of the proposed merchant power facility for CO, NO_2, SO_2 and PM_{10} are well below the threshold limits necessary to have adverse impacts on surrounding vegetation.

The nearest Class I area to the proposed merchant power facility is the Mammoth Cave National Park located approximately 310 km southeast in Kentucky. Operation of the proposed merchant power facility will not adversely affect the visibility at this Class I area. Modeling results taken from EPA's VISCREEN model showed no significant visibility impairment on Mammoth Caves as a result of this project. The results of the additional impact analysis conclude the Duke Energy's proposed merchant power facility will have no adverse impact on economic growth, soils, vegetation or visibility in the vicinity or on any Class I area.

APPENDIX A - Long Term and Short Model Comparison for NO_2 (ug/m3)						
Pollutant	**Model Used**	**1987**	**1988**	**1989**	**1990**	**1991**
NO_2	ISCLT	0.056	0.048	0.044	0.05	0.053
NO_2	ISCST	0.14	0.15	0.13	0.15	0.15

APPENDIX B - Worst-Case Scenario Determination for 8 units for Duke Energy						
Scenario #1 (Temperature at -23^{o}F, Load at 100%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	6.28	31.06		6.14		
NO_2	24.61					0.97
PM_{10}	1.26				0.52	0.05
SO_2	7.28		12.0		2.98	0.29
Scenario #2 (Temperature at -23^{o}F, Load at 75%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	4.71	26.91		5.97		
NO_2	18.46					0.93
PM_{10}	1.26				0.63	0.06
SO_2	5.46		10.4		2.73	0.28
Scenario #3 (Temperature at -23^{o}F, Load at 50%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	3.14	23.69		6.39		
NO_2	12.31					0.74
PM_{10}	1.26				1.03	0.08
SO_2	3.64		13.38		2.99	0.22

Scenario #4 (Temperature at 53^{o}F, Load at 100%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	5.4	28.24		5.98		

NO_2	20.97					0.93
PM_{10}	1.26				0.57	0.06
SO_2	6.15		10.72		2.76	0.27
Scenario #5 (Temperature at 53^{o}F, Load at 75%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	4.06	27.08		7.81		
NO_2	15.74					0.89
PM_{10}	1.26				0.86	0.07
SO_2	4.62		15.98		3.15	0.26
Scenario #6 (Temperature at 53^{o}F, Load at 50%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	2.7	20.37		6.52		
NO_2	10.49					0.73
PM_{10}	1.26				1.33	0.09
SO_2	3.08		13.53		3.25	0.21

Scenario #7 (Temperature at 104^{o}F, Load at 100%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	4.65	26.57		5.91		
NO_2	17.71					0.9
PM_{10}	1.26				0.63	0.06
SO_2	5.27		10.66		2.64	0.27
Scenario #8 (Temperature at 104^{o}F, Load at 75%, Diesel Fuel)						
	Emission Rates	**Maximum Concentrations (ug/m3)**				
Pollutant	**(g/sec)**	**1-hour**	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	3.49	26.31		7.85		
NO_2	13.29					0.87
PM_{10}	1.26				1.24	0.08
SO_2	3.96		16.2		3.9	0.26

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Scenario #9 (Temperature at 104^{o}F, Load at 50%, Diesel Fuel)						
	Emission Rates	Maximum Concentrations (ug/m3)				
Pollutant	(g/sec)	1-hour	3-hour	8-hour	24-hour	Annual
CO	2.32	18.7		6.11		
NO_2	8.85					0.64
PM_{10}	1.26				1.44	0.09
SO_2	2.64		12.7		3.01	0.19

Scenario #10 (Load at 100%, Natural Gas)						
	Emission Rates	Maximum Concentrations (ug/m3)				
Pollutant	(g/sec)	1-hour	3-hour	8-hour	24-hour	Annual
CO	7.91	48.2		10.52		
NO_2	8.16					0.43
PM_{10}	0.63				0.66	0.07
SO_2	0.09		0.19		0.05	0.0
Scenario #11 (Load at 75%, Natural Gas)						
	Emission Rates	Maximum Concentrations (ug/m3)				
Pollutant	(g/sec)	1-hour	3-hour	8-hour	24-hour	Annual
CO	5.94	44.8		13.8		
NO_2	6.13					0.42
PM_{10}	0.63				1.29	0.09
SO_2	0.06		0.25		0.06	0.0
Scenario #12 (Load at 50%, Natural Gas)						
	Emission Rates	Maximum Concentrations (ug/m3)				
Pollutant	(g/sec)	1-hour	3-hour	8-hour	24-hour	Annual
CO	3.96	37.0		10.81		
NO_2	4.08					0.31
PM_{10}	0.63				1.49	0.09
SO_2	0.05		0.25		0.06	0.0

APPENDIX C - RPM-IV RUNS for Duke Energy				
NAAQS Analysis for Ozone (June 25, 1991)				
Time	**Distance**	**Ambient**	**Plume-Injected**	**Source Impact**
(hours)	(meters)	(ppb)	(ppb)	(ppb)
700.0	100.0	15.0	15.4	0.4
800.0	9700.0	37.3	38.1	0.8
900.0	20500.0	56.9	56.4	-0.5
1000.0	58600.0	73.7	73.4	-0.3
1100.0	34200.0	88.3	88	-0.3
1200.0	41700.0	98.9	99	0.1
1300.0	53000.0	106	105	-1
1400.0	67100.0	110	108	-2
1500.0	82400.0	112	109	-3
1600.0	98700.0	113	109	-4
1700.0	115000.0	113	110	-3
1800.0	131000.0	113	110	-3
1900.0	146000.0	113	110	-3
NAAQS Analysis for Ozone (June 18, 1994)				
Time	**Distance**	**Ambient**	**Plume-Injected**	**Source Impact**
(hours)	(meters)	(ppb)	(ppb)	(ppb)
700.0	100.0	27.1	27.3	0.2
800.0	4710.0	53.4	53.6	0.2
900.0	18100.0	74.3	73.9	-0.4
1000.0	33700.0	90.6	89.9	-0.7
1100.0	45400.0	104	104	0
1200.0	57800.0	112	112	0
1300.0	73500.0	117	116	-1
1400.0	88100.0	119	116	-3
1500.0	102000.0	120	116	-4
1600.0	116000.0	120	116	-4
1700.0	130000.0	120	117	-3
1800.0	141000.0	120	118	-2
1900.0	153000.0	120	118	-2

Commercial/Institutional/Residential Combustors
#1 and #2 Fuel Oil
Two (2) emergency generators @ 17.21 MMBtu/hr each

Company Name: **Vermillion Generating Station**
Address, City IN Zip: **SW Quadrant of Intersectionof CR 300N and SR 63, Eugene Township, Indiana**
CP: **165-10476**
Plt ID: **165-00022**
Reviewer: NLJ
Date: 02/08/99

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.05
34.42	2153.70857	

	Pollutant				
	PM	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.1	0.0505 *(1.01S)*	3.2	0.09	0.9
Potential to Emit in tons/yr	15.1	7.6	482.4	13.6	128.1
Lmited Potential to Emit in tons/yr	0.9	0.4	27.5	0.8	7.3

Methodology
Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu
Limited Potential to Emit (tons/yr) = Heat Input Capacity (MMBtu/hr) x 500 hrs/yr x Emission Factor (lb/MMbtu) x ton/2000 lbs
Emission Factors are from AP 42, Tables 3.4-1, 3.4-2, and3.4-3 (SCC 2-02-004-01) 10/96
PM Emission Factor is Condensable and Filterable PM
Emission (tons/yr) = Heat input (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760 hr/yr /2,000 lb/ton

HAPs

	Benzene	Toluene	Xylene	Propylene	Formaldehyde
Emission Factor in lb/mmBtu	7.8E-04	2.8E-04	1.9E-04	2.8E-03	7.9E-05
Potential to Emit in tons/yr	1.170E-01	4.236E-02	2.910E-02	4.206E-01	1.189E-02
Limited Potential to Emit in tons/yr	6.68E-03	2.42E-03	1.66E-03	2.40E-02	6.79E-04

HAPs (continued)

	Acetaldehyde	Acrolein
Emission Factor in lb/mmBtu	2.5E-05	7.9E-06
Potential Emission in tons/yr	3.799E-03	1.188E-03
Limited Potential to Emit in tons/yr	2.17E-04	6.78E-05

Methodology
No data was available in AP-42 for organic HAPs.
Potential to emit (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton
Limited Potential to emit (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*500 hrs/yr / 2,000 lb/ton

Appendix A: Emissions Calculations
Commercial/Institutional/Residential Combustors
#1 and #2 Fuel Oil
One (1) diesel fire pump

Company Name: **Vermillion Generating Station**
Address, City IN Zip: **SW Quadrant of Intersection of CR 300N and SR 63, Eugene Township, Indiana**
CP: **165-10476**
Plt ID: **165-00022**
Reviewer: NLJ
Date: 02/08/99

Heat Input Capacity MMBtu/hr	Potential Throughput kgals/year	S = Weight % Sulfur
		0.05
1.6	100.114286	

	Pollutant				
	PM	SO2	NOx	VOC	CO
Emission Factor in lb/MMBtu	0.1	0.0505 *(1.01S)*	3.2	0.09	0.9
Potential to Emit in tons/yr	0.7	0.4	22.4	0.6	6.0
Limited Potential to Emit in tons/yr	0.04	0.0202	1.28	0.036	0.34

Methodology

1 gallon of No. 2 Fuel Oil has a heating value of 140,000 Btu

Potential Throughput (kgals/year) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1kgal per 1000 gallon x 1 gal per 0.140 MM Btu

Emission Factors are from AP 42, Tables 3.4-1, 3.4-2, and 3.4-3 (SCC 2-02-004-01) 10/96

PM Emission Factor is Condensable and Filterable PM

Emission (tons/yr) = Heat input (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760 hr/yr /2,000 lb/ton

Limited Emission (tons/yr) = Heat input (MMBtu/hr) x Emission Factor (lb/MMBtu) * 500 hr/yr /2,000 lb/ton

HAPs

	Benzene	Toluene	Xylene	Propylene	Formaldehyde
Emission Factor in lb/mmBtu	7.8E-04	2.8E-04	1.9E-04	2.8E-03	7.9E-05
Potential Emission in tons/yr	5.438E-03	1.969E-03	1.353E-03	1.955E-02	5.529E-04
Limited Potential to Emit in tons/yr	3.10E-04	1.12E-04	7.72E-05	1.12E-03	3.16E-05

HAPs (continued)

	Acetaldehyde	Acrolein
Emission Factor in lb/mmBtu	2.5E-05	7.9E-06
Potential Emission in tons/yr	1.766E-04	5.522E-05
Limited Potential to Emit in tons/yr	1.01E-05	3.15E-06

Methodology

No data was available in AP-42 for organic HAPs.

Potential to Emit (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*8,760 hrs/yr / 2,000 lb/ton

Limited Potential to Emit (tons/year) = Throughput (mmBtu/hr)*Emission Factor (lb/mmBtu)*500 hrs/yr / 2,000 lb/ton

HAPs Emissions for distillate oil-fired turbines

Company Name: Vermillion Generating Station
Address, City IN Zip: SW Quadrant of Intersection of CR 300N and SR 63, Eugene Township, Indiana
CP: 165-10476
Plt ID: 165-00022
Reviewer: NLJ
Date: 04/27/1999
Eight (8) combustion turbines @ 1272.2 MMBtu/hr each
Heat Input Capacity: 10177.6 MMBtu/hr

Pollutant	Emission Factor (lbs/MMBtu)	Total Emissions (tons/yr)	Emissions Per Turbine (tons/yr)	Total Limited Emissions (tons/yr)	Limited Emissions Per Turbine (tons/yr)
Acetaldehyde	2.52E-05	1.123	0.140	0.064	0.0080
Acrolein	7.88E-06	0.351	0.044	0.020	0.0025
Antimony	2.20E-05	0.981	0.123	0.056	0.0070
Arsenic	4.90E-06	0.218	0.027	0.012	0.0016
Benzene	7.76E-04	34.592	4.324	1.974	0.2468
Beryllium	3.30E-07	0.015	0.002	0.0008	0.0001
Cadmium	4.20E-06	0.187	0.023	0.011	0.0013
Chromium	4.70E-05	2.095	0.262	0.120	0.0149
Cobalt	9.10E-06	0.406	0.051	0.023	0.0029
Formaldehyde	7.89E-05	3.517	0.440	0.201	0.0251
Lead	5.80E-05	2.586	0.323	0.148	0.0184
Manganese	2.30E-04	10.253	1.282	0.585	0.0732
Mercury	9.10E-07	0.041	0.005	0.0023	0.0003
Napthalene	1.30E-04	5.795	0.724	0.331	0.0413
Nickel	1.20E-03	53.493	6.687	3.053	0.3817
Phosphorus	3.00E-04	13.373	1.672	0.763	0.0954
POM	8.20E-05	3.655	0.457	0.209	0.0261
Selenium	5.30E-06	0.236	0.030	0.013	0.0017
Toluene	2.81E-04	12.526	1.566	0.715	0.0894
Xylene	1.93E-04	8.604	1.075	0.491	0.0614
TOTAL		**154.05**	**19.26**	**8.79**	**1.0991**

Methodology
Emission Factors for metal HAPs are from AP-42 (Fifth Edition, October 1996), Table 3.1-4
Emission Factors for organic HAPs have been based on information supplied by Duke Energy (Appendix B of permit application)
Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760 hr/yr / 2,000 lb/ton
Limited Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 500 hr/yr / 2,000 lb/ton

HAPs Emissions for natural gas-fired turbines

Company Name:	Vermillion Generating Station
Address, City IN Zip:	SW Quadrant of Intersection of CR 300N and SR 63, Eugene Township, Indiana
CP:	165-10476
Plt ID:	165-00022
Reviewer:	NLJ
Date:	04/27/1999
	Eight (8) combustion turbines @ 1178.4 MMBtu/hr each
Heat Input Capacity:	9427.2 MMBtu/hr

Pollutant	Emission Factor (lbs/MMBtu)	Total Emissions (tons/yr)	Emissions Per Turbine (tons/yr)	Total Limited Emissions (tons/yr)	Limited Emissions Per Turbine (tons/yr)
Acetaldehyde	6.100E-05	2.519	0.315	0.719	0.090
Acrolein	3.700E-05	1.528	0.191	0.436	0.055
Benzene	7.100E-04	29.317	3.665	8.367	1.046
Formaldehyde	1.750E-03	72.259	9.032	20.622	2.578
Napthalene	4.900E-05	2.023	0.253	0.577	0.072
Toluene	2.300E-04	9.497	1.187	2.710	0.339
Xylene	5.900E-05	2.436	0.305	0.695	0.087
TOTAL		**119.58**	**14.95**	**34.13**	**4.27**

Methodology

Emission Factors for organic HAPs have been based on information supplied by Duke Energy (Appendix B of permit application)
Formaldehyde emissions were assumed to be 100% of the VOC emissions, therefore the vendor VOC information supplied was used.
Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 8760 hr/yr / 2,000 lb/ton
Limited Emissions (tons/yr) = Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu) * 2500 hr/yr / 2,000 lb/ton