City of Indianapolis DPW Department of Public Works
Bart Peterson, Mayor

TO: Interested Parties / Applicant

RE: Citizens Gas & Coke Utility – LNG North / F097-18805-00141

FROM: Felicia A. Robinson
Administrator

Notice of Decision: Approval - Effective Immediately

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the enclosed matter. Pursuant to IC 13-15-5-3, this permit is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Room 1049, Indianapolis, IN 46204, **within fifteen (15) calendar days of the receipt of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:

(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:

(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

If you have technical questions regarding the enclosed documents, please contact the Indianapolis Office of Environmental Services, Air Permits at (317) 327-2234.

Enclosures

Clean air is in
visible
describable
vigorating
valuable
credible
Air Quality Hotline: 317-327-4AIR I knozone.com

Department of Public Works
Office of Environmental Services
2700 Belmont Avenue
Indianapolis, IN 46221
317-327-2234
Fax 327-2274
TDD 327-5186
indygov.org/dpw

FEDERALLY ENFORCEABLE STATE OPERATING PERMIT (FESOP) RENEWAL
OFFICE of AIR QUALITY
and
CITY of INDIANAPOLIS
OFFICE of ENVIRONMENTAL SERVICES

Citizens Gas and Coke Utility - LNG North
4536 West 86th Street
Indianapolis, Indiana 46268

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

The Permittee must comply with all conditions of this permit. Noncompliance with any provision of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; and denial of a permit renewal application. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-8 as required by 42 U.S.C. 7401, et. seq. (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70.6, IC 13-15 and IC 13-17. This permit also addresses new source review requirements and is intended to fulfill the new source review procedures and permit revision requirements pursuant to 326 IAC 2-8-11.1, applicable to those conditions.

Operation Permit No.: F097-18805-00141	
Issued by: Felicia A. Robinson Administrator Office of Environmental Services	Issuance Date: December 21, 2006 Expiration Date: December 21, 2011

Department of Public Works
Office of Environmental Services
2700 Belmont Avenue
Indianapolis, IN 46221
317-327-2234
Fax 327-2274
TDD 327-5186
indygov.org/dpw

SECTION A SOURCE SUMMARY

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

A.1 General Information [326 IAC 2-8-3(b)]

The Permittee owns and operates a liquefied natural gas storage plant.

Authorized individual:	Vice President of Gas Operations
Source Address:	4536 West 86th Street, Indianapolis, IN 46268
Mailing Address:	4536 West 86th Street, Indianapolis, IN 46268
General Source Phone:	(317) 927-6016
SIC Code:	4922
Source Location Status:	Marion County Nonattainment for 8-hour ozone and PM2.5 Attainment for all other criteria pollutants
Source Status:	Federally Enforceable State Operating Permit (FESOP) Minor Source, under PSD and Emission Offset Rules; Minor Source, Section 112 of the Clean Air Act

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-8-3(c)(3)]

This stationary source consists of the following emission units and pollution control devices:

(a) One (1) Allison simple cycle Gas Turbine for refrigerant compressor, identified as Emission Unit ID 01 and exhausting at Stack/Vent ID S01. Natural gas fired at 38.0 million Btu per hour maximum heat input. Model number 501-KC5. Installation date of 1990. Under 40 CFR 60.330, Subpart GG (Standards of Performance for Stationary Gas Turbines), the Allison simple cycle Gas Turbine is considered a stationary gas turbine. Emission Unit ID 01 includes non HAP VOC emissions from the natural gas liquefaction compressor/heat exchange system.

(b) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 02 and exhausting at Stack/Vent ID 02-A1 and 02-A2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 02 is considered a steam generating unit.

(c) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 03 and exhausting at Stack/Vent ID 03-B1 and 03-B2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 03 is considered a steam generating unit.

(d) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 04 and exhausting at Stack/Vent ID 04-C1 and 04-C2.

Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 04 is considered a steam generating unit.

A.3 Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-8-3(c)(3)(I)]

This stationary source also includes the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Natural gas-fired combustion sources with heat input equal to or less than ten (10) million BTU per hour:

(1) Salt Bath heater for mole sieve regeneration, operated while natural gas is being liquefied, identified as Emission Unit ID SBH-01, with a maximum heat input capacity of 6.5 MMBtu/hr. [326 IAC 6-2-4]

(b) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume.

(c) Process vessel degassing and cleaning to prepare for internal repairs.

(d) Purging of gas lines and vessels that is related to routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process.

(e) Equipment used to collect any material that might be released during a malfunction, process upset or spill cleanup including catch tanks, temporary liquid separators, tanks and fluid handling equipment.

(f) On site fire and emergency response training approved by the department.

(g) Natural gas turbines or reciprocating engines not exceeding 16,000 horsepower, including:

(1) Emission Unit ID WEG 1, Waukesha Emergency Generator, natural gas fired at 6.0 million Btu per hour or an equivalent horsepower rating of 2346 at 1750 kilowatts. [326 IAC 2-3]

(h) Stationary fire pumps, including:

(1) Emission Unit ID EFP-01, diesel fuel fired emergency fire pump, rated at 459 horse power. [326 IAC 2-3]

(i) Purge double block and bleed valves.

(j) One (1) ethylene storage tank at 12,000 gallon storage capacity, identified as Emission Unit ID Ethylene Storage Tank, installed in 1990. [326 IAC 8-1-6]

(k) One (1) pentane storage tank at 10,000 gallon storage capacity, identified as Emission Unit ID Pentane Storage Tank, installed in 1990.

(l) One (1) butane storage tank and one (1) propane storage tank, identified as Emission Unit ID Butane Storage Tank, and Emission Unit ID Propane Storage Tank, respectively,

each at 3,500 gallon storage capacity, and one (1) odorant storage tank at 100 gallon capacity, all installed in 1990.

A.4 FESOP Applicability [326 IAC 2-8-2]

This stationary source, otherwise required to have a Part 70 permit as described in 326 IAC 2-7-2(a), has applied to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) and the City of Indianapolis, Office of Environmental Services (OES) to renew a Federally Enforceable State Operating Permit (FESOP).

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-8-1]

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2, and 326 IAC 2-7) shall prevail.

B.2 Permit Term [326 IAC 2-8-4(2)][326 IAC 2-1.1-9.5][IC 13-15-3-6(a)]

(a) This permit, F097-18805-00141, is issued for a fixed term of five (5) years from the issuance date of this permit, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date.

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, until the renewal permit has been issued or denied.

B.3 Term of Conditions [326 IAC 2-1.1-9.5]

Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

B.4 Enforceability [326 IAC 2-8-6]

(a) Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM and the City of Indianapolis, OES, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

(b) Unless otherwise stated, all terms and conditions in this permit that are local requirements, including any provisions designed to limit the source's potential to emit, are enforceable by the City of Indianapolis, OES.

B.5 Severability [326 IAC 2-8-4(4)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-8-4(5)(D)]

This permit does not convey any property rights of any sort, or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-8-4(5)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, and the City of Indianapolis, Office of Environmental Services (OES) within a reasonable time, any information that IDEM, OAQ, and the City of Indianapolis, OES may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The submittal by the Permittee does require the

certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1). Upon request, the Permittee shall also furnish to IDEM, OAQ, and the City of Indianapolis, OES copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1 when furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Compliance Order Issuance [326 IAC 2-8-5(b)]

IDEM, OAQ and the City of Indianapolis, OES may issue a compliance order to this Permittee upon discovery that this permit is in nonconformance with an applicable requirement. The order may require immediate compliance or contain a schedule for expeditious compliance with the applicable requirement.

B.9 Certification [326 IAC 2-8-3(d)] [326 IAC 2-8-4(3)(C)(i)] [326 IAC 2-8-5(1)]

(a) Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by an authorized individual of truth, accuracy, and completeness. This certification, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) One (1) certification shall be included, using the attached Certification Form, with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) An authorized individual is defined at 326 IAC 2-1.1-1(1).

B.10 Annual Compliance Certification [326 IAC 2-8-5(a)(1)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted in letter form no later than April 15 of each year to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

(b) The annual compliance certification report required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document

is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, and the City of Indianapolis, OES on or before the date it is due.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-8-4(3); and

(5) Such other facts as specified in Sections D of this permit, IDEM, OAQ, and the City of Indianapolis, OES may require to determine the compliance status of the source.

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

B.11 Preventive Maintenance Plan [326 IAC 1-6-3] [326 IAC 2-8-4(9)] [326 IAC 2-8-5(a)(1)]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, including the following information on each facility:-

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

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

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

(b) A copy of the PMPs shall be submitted to IDEM, OAQ, and OES upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ and OES. IDEM, OAQ and OES may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions or potential to emit. The PMPs do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

(c) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.12 Emergency Provisions [326 IAC 2-8-12]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation, except as provided in 326 IAC 2-8-12.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a health-based or technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describes the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ and OES, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone No.: 1-800-451-6027 (ask for IDEM, OAQ Compliance Section) or,
Telephone No.: 317-233-0178 (ask for IDEM, OAQ Compliance Section)
Facsimile No.: 317-233-6865

City of Indianapolis OES
Telephone No.: 317/327-2234 (ask for OES Air Compliance Section)
Facsimile No.: 317/327-2274

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

Indianapolis Office of Environmental Services
Air Compliance
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-8-4(3)(C)(ii) and must contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ and OES may require that the Preventive Maintenance Plans required under 326 IAC 2-8-3(c)(6) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ and OES, by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-8 and any other applicable rules.

(g) Operations may continue during an emergency only if the following conditions are met:

(1) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

(2) If an emergency situation causes a deviation from a health-based limit, the Permittee may not continue to operate the affected emissions facilities unless:

(A) The Permittee immediately takes all reasonable steps to correct the emergency situation and to minimize emissions; and

(B) Continued operation of the facilities is necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw material of substantial economic value.

Any operations shall continue no longer than the minimum time required to prevent the situations identified in (g)(2)(B) of this condition.

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report.

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5]

(a) All terms and conditions of permits established prior to F097-18805-00141 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised

(3) deleted

(b) All previous registrations and permits are superseded by this permit.

B.14 Termination of Right to Operate [326 IAC 2-8-9] [326 IAC 2-8-3(h)]

The Permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-8-3(h) and 326 IAC 2-8-9.

B.15 Deviations from Permit Requirements and Conditions [326 IAC 2-8-4(3)(C)(ii)]

(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provision), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. A deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report.

The Quarterly Deviation and Compliance Monitoring Report does require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(b) A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

B.16 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-8-4(5)(C)] [326 IAC 2-8-7(a)] [326 IAC 2-8-8]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a FESOP modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit. [326 IAC 2-8-4(5)(C)] The notification by the Permittee does require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ or the City of Indianapolis, OES determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-8-8(a)]

(c) Proceedings by IDEM, OAQ or the City of Indianapolis, OES, to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-8-8(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-8-8(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ or the City of Indianapolis, OES, at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ or the City of Indianapolis, OES, may provide a shorter time period in the case of an emergency. [326 IAC 2-8-8(c)]

B.17 Permit Renewal [326 IAC 2-8-3(h)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ, and OES and shall include the information specified in 326 IAC 2-8-3. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require the certification by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

Office of Environmental Services
Administration Building
2700 South Belmont Ave.
Indianapolis, IN 46221

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) If the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, and OESon or before the date it is due.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-8 until IDEM, OAQ and

OES takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified in writing by IDEM, OAQ and OES any additional information identified as being needed to process the application.

B.18 Permit Amendment or Revision [326 IAC 2-8-10] [326 IAC 2-8-11.1]

(a) Permit amendments and revisions are governed by the requirements of 326 IAC 2-8-10 or 326 IAC 2-8-11.1 whenever the Permittee seeks to amend or modify this permit.

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

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

Any such application shall be certified by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(c) The Permittee may implement the administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-8-10(b)(3)]

B.19 Operational Flexibility [326 IAC 2-8-15][326 IAC 2-8-11.1]

(a) The Permittee may make any change or changes at this source that are described in 326 IAC 2-8-15(b) through (d), without prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-8-11.1 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-8-15(b) through (d). The Permittee shall make such records available, upon reasonable request, to public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ and OES in the notices specified in 326 IAC 2-8-15(b)(2), (c)(1), and (d).

(b) Emission Trades [326 IAC 2-8-15(c)]
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-8-15(c).

(c) Alternative Operating Scenarios [326 IAC 2-8-15(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-8-4(7). No prior notification of IDEM, OAQ or U.S. EPA is required.

(d) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

B.20 Source Modification Requirement [326 IAC 2-8-11.1]

A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2 and 326 IAC 2-8-11.1

B.21 Inspection and Entry [326 IAC 2-8-5(a)(2)][IC 13-14-2-2][IC 13-17-3-2][IC13-30-3-1]

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

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

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-8-10]

(a) The Permittee must comply with the requirements of 326 IAC 2-8-10 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

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

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-8-10(b)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-8-4(6)] [326 IAC 2-8-16][326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ, within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.

(b) Failure to pay may result in administrative enforcement action, or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-8-4(3)][326 IAC 2-8-5][62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any condition of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emissions Limitations and Standards [326 IAC 2-8-4(1)]

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

C.2 Overall Source Limit [326 IAC 2-8]

The purpose of this permit is to limit this source's potential to emit to less than major source levels for the purpose of Section 502(a) of the Clean Air Act.

(a) Pursuant to 326 IAC 2-8:

(1) The potential to emit any regulated pollutant, except particulate matter (PM), from the entire source shall be limited to less than one-hundred (100) tons per twelve (12) consecutive month period.

(2) The potential to emit any individual hazardous air pollutant (HAP) from the entire source shall be limited to less than ten (10) tons per twelve (12) consecutive month period; and

(3) The potential to emit any combination of HAPs from the entire source shall be limited to less than twenty-five (25) tons per twelve (12) consecutive month period.

(b) This condition shall include all emission points at this source including those that are insignificant as defined in 326 IAC 2-7-1(21). The source shall be allowed to add insignificant activities not already listed in this permit, provided that the source's potential to emit does not exceed the above specified limits.

(c) Section D of this permit contains independently enforceable provisions to satisfy this requirement.

C.3 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of thirty percent (30%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

C.4 Open Burning [326 IAC 4-1] [IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

C.5 Incineration [326 IAC 4-2] [326 IAC 9-1-2(3)]

The Permittee shall not operate an incinerator or incinerate any waste or refuse except as provided in 326 IAC 4-2 and in 326 IAC 9-1-2.

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

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

C.7 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140.

Testing Requirements [326 IAC 2-8-4(3)]

C.8 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 any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

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

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ, and the City of Indianapolis, OES not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ, and the City of Indianapolis, OES,

if the Permittee submits to IDEM, OAQ, a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period.

Compliance Requirements [326 IAC 2-1.1-11]

C.9 Compliance Requirements [326 IAC 2-1.1-11]

The Commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-8-4] [326 IAC 2-8-5(a)(1)]

C.10 Compliance Monitoring [326 IAC 2-8-4(3)] [326 IAC 2-8-5(a)(1)]

Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

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

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a permit revision shall be implemented when operation begins.

C.11 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60 Appendix B, 40 CFR 63 or other approved methods as specified in this permit.

Corrective Actions and Response Steps [326 IAC 2-8-4] [326 IAC 2-8-5(a)(1)]

C.12 Risk Management Plan [326 IAC 2-8-4] [40 CFR 68]

If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.13 Response to Excursions or Exceedances [326 IAC 2-8-4] [326 IAC 2-8-5]

(a) Upon detecting an excursion or exceedance, the Permittee shall restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Corrective actions may include, but are not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;

(2) review of operation and maintenance procedures and records;

(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall maintain the following records:

(1) monitoring data;

(2) monitor performance data, if applicable; and

(3) corrective actions taken.

C.14 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-8-4][326 IAC 2-8-5]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate response actions. The Permittee shall submit a

description of these response actions to IDEM, OAQ, within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one-hundred and twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

Record Keeping and Reporting Requirements [326 IAC 2-8-4(3)]

C.15 General Record Keeping Requirements [326 IAC 2-8-4(3)] [326 IAC 2-8-5]

(a) Records of all required monitoring data, reports and support information required by this permit 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 physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner or the City of Indianapolis, OES makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner or the City of Indianapolis, OES within a reasonable time.

(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance.

C.16 General Reporting Requirements [326 IAC 2-8-4(3)(C)] [326 IAC 2-1.1-11]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the "authorized individual" as defined by 326 IAC2-1.1-1(1).

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

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

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

(d) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(e) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

Stratospheric Ozone Protection

C.17 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with the standards for recycling and emissions reduction:

(a) Persons opening appliances for maintenance, service, repair or disposal must comply with the required practices pursuant to 40 CFR 82.156

(b) Equipment used during the maintenance, service, repair or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

(c) Persons performing maintenance, service, repair or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

SECTION D.1 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-8-4(10)]:

(a) One (1) Allison simple cycle Gas Turbine for refrigerant compressor, identified as Emission Unit ID 01 and exhausting at Stack/Vent ID S01. Natural gas fired at 38.0 million Btu per hour maximum heat input. Model number 501-KC5. Installation date of 1990. Under 40 CFR 60.330, Subpart GG (Standards of Performance for Stationary Gas Turbines), the Allison simple cycle Gas Turbine is considered a stationary gas turbine. Emission Unit ID 01 includes non HAP VOC emissions from the natural gas liquefaction compressor/heat exchange system.

(b) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 02 and exhausting at Stack/Vent ID 02-A1 and 02-A2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 02 is considered a steam generating unit.

(c) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 03 and exhausting at Stack/Vent ID 03-B1 and 03-B2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 03 is considered a steam generating unit.

(d) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 04 and exhausting at Stack/Vent ID 04-C1 and 04-C2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 04 is considered a steam generating unit.

INSIGNIFICANT ACTIVITIES

(a) Natural gas-fired combustion sources with heat input equal to or less than ten (10) million BTU per hour:

(1) Salt bath heater for mole sieve regeneration, operated while natural gas is being liquefied, identified as Emission Unit ID SBH-01, with a maximum heat input capacity of 6.5 MMBtu/hr. [326 IAC 6-2-4]

(g) Natural gas turbines or reciprocating engines not exceeding 16,000 horsepower, including:

(1) Emission Unit ID WEG 1, Waukesha Emergency Generator, natural gas fired at 6.0 million Btu per hour or an equivalent horsepower rating of 2346 at 1750 kilowatts. [326 IAC 2-3]

(h) Stationary fire pumps, including:

(1) Emission Unit ID EFP-01, diesel fuel fired emergency fire pump, rated at 459 horse power. [326 IAC 2-3]

Facility Description [326 IAC 2-8-4(10)]:

(j) One (1) ethylene storage tank at 12,000 gallon storage capacity, identified as Emission Unit ID Ethylene Storage Tank, installed in 1990. [326 IAC 8-1-6]

(k) One (1) pentane storage tank at 10,000 gallon storage capacity, identified as Emission Unit ID Pentane Storage Tank, installed in 1990.

(l) One (1) butane storage tank and one (1) propane storage tank, identified as Emission Unit ID Butane Storage Tank, and Emission Unit ID Propane Storage Tank, respectively, each at 3,500 gallon storage capacity, and one (1) odorant storage tank at 100 gallon capacity, all installed in 1990.

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

Emission Limitations and Standards [326 IAC 2-8-4(1)]

D.1.1 Emission Offset Minor Limit [326 IAC 2-3] [326 IAC 2-8] [Installation Permit 900141-01]

(a) Pursuant to Installation Permit number 900141-01, issued November 6, 1990:

(1) Nitrogen Oxides (NO_X) emissions from Emission Unit ID 01, the one (1) Allison simple cycle Gas Turbine, shall be limited to 32.1 pounds per hour.

(2) The nitrogen content for gas turbine fuel consumed in Emission Unit ID 01, the one (1) Allison simple cycle Gas Turbine, shall be limited to 23.2 percent by weight.

(b) Pursuant to 326 IAC 2-8-4 (FESOP; Permit Content):

(1) Nitrogen Oxides (NO_X) emissions from the Allison simple cycle Gas Turbine, identified as Emission Unit ID 01, shall not exceed 846 pounds per million cubic feet (lbs/MMCF) of natural gas burned.

(2) Nitrogen Oxides (NO_X) emissions from each of the three T-Thermal water submerged Vaporizers, identified as Emission Unit ID 02, 03 and 04, shall not exceed 100 pounds per million cubic feet (lbs/MMCF) of natural gas burned.

(3) Nitrogen Oxides (NO_X) emissions from the Waukesha Emergency Generator, identified as Emission Unit ID WEG 1, shall not exceed 3,170 pounds per million cubic feet (lbs/MMCF) of natural gas burned.

(4) Nitrogen Oxides (NO_X) emissions from the diesel fuel fired emergency fire pump, Emission Unit ID EFP-01, shall not exceed 0.6 pounds per gallon (lbs/gal) of diesel fuel burned.

(5) The combined total Nitrogen Oxides (NO_X) emissions from the Allison simple cycle Gas Turbine, Emission Unit ID 01, the three T-Thermal water submerged Vaporizers, Emission Unit IDs 02 – 04, the Waukesha Emergency Generator, Emission Unit ID WEG 1, and the diesel fuel fired emergency fire pump, Emission Unit ID EFP-01, shall not exceed 93.06 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance with this condition shall limit total NO_X emissions from the source to less than 100 tons per twelve (12) consecutive month period with compliance determined at the end of each month and demonstrates compliance with 326 IAC 2-3 (Emission Offset) and Installation Permit number 900141-01, issued November 6, 1990. Therefore, the requirements of 326 IAC 2-7 (Part 70) and 326 IAC 2-3 (Emission Offset) do not apply to the source.

D.1.2 Volatile Organic Compounds (VOC) [326 IAC 8-1-6]

(a) Pursuant to 326 IAC 8-1-6, VOC input to the natural gas liquefaction compressor/heat exchange system shall be limited such that the potential to emit of VOC is less than ninety (90.0) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) Ethylene (VOC) input not sent to the natural gas liquefaction compressor/heat exchange system from Emission Unit ID Ethylene Storage Tank shall only be vented into the vapor feed line directly into the natural gas distribution system.

D.1.3 Particulate Matter (PM) [326 IAC 6-2-1][326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating), the allowable PM emission rate from the three T-Thermal water submerged Vaporizers, identified as Emission Unit ID 02, 03 and 04, and the Salt Bath heater for mole sieve regeneration, identified as Emission Unit ID SBH-01, based on a total heat input rate of 222.50 MMBtu per hour, shall each be limited to 0.27 pound per MMBtu heat input.

This limitation is based on the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

where: Pt = Pounds of particulate matter emitted per MMBtu heat input.
Q = Total source maximum operating capacity rating in MMBtu per hour.

D.1.4 Preventive Maintenance Plan [326 IAC 2-8-4(9)]

A Preventive Maintenance Plan, in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for Emission Unit ID 01 through 04 and any control devices.

Compliance Determination Requirements

D.1.5 Nitrogen Oxides (NO_X) Emissions

Compliance with Condition D.1.1 shall be determined by the following equation:

E = [(846 lbs/MMCF) x (actual monthly fuel use in MMCF this month in the Allison simple cycle Gas Turbine) + (100 lbs/MMCF) x (combined actual monthly fuel use in MMCF this month in the three T-Thermal water submerged Vaporizers) + (3,170 lbs/MMCF) x (actual monthly fuel use in MMCF this month in the Waukesha Emergency Generator) + (0.6 lbs/gal) x (actual monthly fuel use in gallons this month in the diesel fuel fired emergency fire pump)] + P

Where: E = actual NO_X emissions per twelve (12) consecutive month period
P = actual NO_X emissions in the previous eleven (11) consecutive month period

D.1.6 VOC Organic Compounds (VOC) [326 IAC 8-1-6]

Compliance with Condition D.1.2 shall be determined at the end of each month using the following equation:

E = (VOC input, in tons, this month – ethylene (VOC), in tons, this month sent to the natural gas distribution system) + P

Where: E = actual VOC emissions per twelve (12) consecutive month period
P = actual VOC emissions in the previous eleven (11) consecutive month period

Record Keeping and Reporting Requirements [326 IAC 2-8-4(3)] [326 IAC 2-8-16]

D.1.7 Record Keeping Requirements

(a) To document compliance with Conditions D.1.1, the Permittee shall maintain records in accordance with (1) through (2) below.

(1) Calendar dates covered in the compliance determination period;

(2) Actual natural gas usage in the Allison simple cycle Gas Turbine (Emission Unit ID 01), the three T-Thermal water submerged Vaporizers (Emission Unit IDs 02 – 04), and the Waukesha Emergency Generator (Emission Unit ID WEG-01) and actual diesel fuel usage in the fire pump (Unit ID EFP-01) per month since the last compliance determination period and NO_X emissions;

(b) To document compliance with Condition D.1.2, the Permittee shall maintain records of (1) through (3) below. Records maintained for (1) through (4) shall be taken monthly and shall be complete and sufficient to establish compliance with the VOC emission limits established in Condition D.1.2. Records necessary to demonstrate compliance shall be available within 30 days of the end of each compliance period.

(1) The monthly total amount of VOC input to the natural gas liquefaction compressor/heat exchange system;

(2) VOC purchase records;

(3) VOC sent to the natural gas distribution system;

(4) Total amount of VOC emitted for each compliance period;

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

D.1.8 Reporting Requirements

A quarterly summary of the information to document compliance with Conditions D.1.1 and D.1.2 shall be submitted to the addresses 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. The report submitted by the Permittee does require the certification by an "authorized individual" as defined by 326 IAC 2-1.1-1(1).

New Source Performance Standards (NSPS) Requirements [326 IAC 2-8-4(1)]

D.1.9 General Provisions Relating to NSPS [40 CFR Part 60, Subpart A][326 IAC 12-1]

(a) The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to Emission Unit ID 01 through 04 as described in this section except when otherwise specified in 40 CFR Part 60, Subpart GG or 40 CFR Part 60, Subpart Dc.

(b) Pursuant to 40 CFR 60.7, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue
Indianapolis, IN 46204-2251

and

City of Indianapolis
Office of Environmental Services
Air Quality Management Section
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

D.1.10 Standards of Performance for Stationary Gas Turbines [40 CFR 60.330 Subpart GG] [326 IAC 12]

Pursuant 40 CFR 60.330 Subpart GG (Standards of Performance for Stationary Gas Turbines), the one (1) Allison simple cycle Gas Turbine, identified as Emission Unit ID 01, shall comply with the following:

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

[44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000]

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be

composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150(14.4)/Y + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and
F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NOX percent by volume)
N [le] 0.015	0
0.015 < N[le] 0.1	0.04(N)
0.1 < N [le] 0.25	0.004+0.0067(N-0.1)
N > 0.25	0.005

Where:
N = the nitrogen content of the fuel (percent by weight).
or:
Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41359, July 8, 2004]

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[44 FR 52798, Sept. 10, 1979, as amended at 69 FR 41360, July 8, 2004]

§ 60.334 Monitoring of operations.

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NO_X emission limit under §60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084–82, 94, D5504–01, D6228–98, or Gas Processors Association Standard 2377–86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.*, if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(*1*) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*2*) of this section.

(*2*) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(*3*) of this section.

(*3*) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.*, daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(4) *Emergency fuel.* Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

[44 FR 52798, Sept. 10, 1979, as amended at 47 FR 3770, Jan. 27, 1982; 65 FR 61759, Oct. 17, 2000; 69 FR 41360, July 8, 2004]

§ 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522–00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O_2, is within ±5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:
$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}$ e19 (Ho−0.00633) $(288°K/T_a)^{1.53}$
Where:
NO_X = emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,
NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2,
P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,
P_o = observed combustor inlet absolute pressure at test, mm Hg,
H_o = observed humidity of ambient air, g H_2O/g air,
e = transcendental constant, 2.718, and
T_a = ambient temperature, °K.

(2) The 3-run performance test required by §60.8 must be performed within ±5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in §60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522–00

(incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597–94 (Reapproved 1999), D6366–99, D4629–02, D5762–02 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129–00, D2622–98, D4294–02, D1266–98, D5453–00 or D1552–01 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, ASTM D1072–80, 90 (Reapproved 1994); D3246–81, 92, 96; D4468–85 (Reapproved 2000); or D6667–01 (all of which are incorporated by reference, see §60.17). The applicable ranges of some ASTM methods mentioned above 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 prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section 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.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

[69 FR 41363, July 8, 2004]

D.1.11 Standards of Performance for Small Industrial-Commercial-Intstitutional Steam Generating Units [40 CFR 60.40c, Subpart Dc]

Pursuant 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Intstitutional Steam Generating Units), the three T-Thermal water submerged Vaporizers, identified as Emission Unit ID 02, 03 and 04, shall each comply with the following:

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to

solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396–78, 89, 90, 92, 96, or 98, “Standard Specification for Fuel Oils” (incorporated by reference—see §60.17).

Dry flue gas desulfurization technology means a sulfur dioxide (SO_2) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835–86, 87, 91, or 97, “Standard Specification for Liquefied Petroleum Gases” (incorporated by reference—see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396–78, 89, 90, 92, 96, or 98, “Standard Specification for Fuel Oils” (incorporated by reference—see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000; 71 FR 9884, Feb. 27, 2006]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000; 71 FR 9886, Feb. 27, 2006]

D.1.12 State Only Heat Transfer Medium NSPS Requirements [326 IAC 12]

Pursuant 326 IAC 12, the Permittee shall comply with the provisions of the July 1, 2002 version of 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Intstitutional Steam Generating Units), which is incorporated by reference by 326 IAC 12 for each of the T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04. The Permittee shall comply with the following:

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388-77, "Standard Specification for Classification of Coals by Rank" (incorporated by reference--see Sec. 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000]

§ 60.48c Reporting and recordkeeping requirements.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000]

The requirements of 326 IAC 12 listed in this condition are not federally enforceable.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
and
CITY OF INDIANAPOLIS
OFFICE OF ENVIRONMENTAL SERVICES

FEDERALLY ENFORCEABLE STATE OPERATING PERMIT (FESOP) CERTIFICATION

Source Name: Citizens Gas & Coke Utility – LNG North
Source Address: 4536 West 86th Street, Indianapolis, IN 46268
Mailing Address: 4536 West 86th Street, Indianapolis, IN 46268
FESOP No.: F097-18805-00141

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

☐ Annual Compliance Certification Letter

☐ Test Result (specify)_____

☐ Report (specify)_____

☐ Notification (specify)_____

☐ Affidavit (specify)_____

☐ Other (specify)_____

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Signature:

Printed Name:

Title/Position:

Date:

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE BRANCH
100 North Senate Avenue
Indianapolis, Indiana 46204-2251
Phone: 317-233-0178
Fax: 317-233-6865

CITY OF INDIANAPOLIS
OFFICE OF ENVIRONMENTAL SERVICES
2700 South Belmont Ave.
Indianapolis Indiana 46221
Phone: 317-327-2234
Fax: 317-327-2274

FEDERALLY ENFORCEABLE STATE OPERATING PERMIT (FESOP)
EMERGENCY OCCURRENCE REPORT

Source Name: Citizens Gas & Coke Utility – LNG North
Source Address: 4536 West 86th Street, Indianapolis, IN 46268
Mailing Address: 4536 West 86th Street, Indianapolis, IN 46268
FESOP No.: F097-18805-00141

This form consists of 2 pages **Page 1 of 2**

☐ This is an emergency as defined in 326 IAC 2-7-1(12)
- The Permittee must notify the Office of Air Quality (OAQ), within four (**4**) business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile within two (**2**) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A **Page 2 of 2**

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N Describe:
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by: _____
Title / Position: _____
Date: _____
Phone: _____

A certification is not required for this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
and
CITY OF INDIANAPOLIS
OFFICE OF ENVIRONMENTAL SERVICES

FESOP Quarterly Report

Source Name: Citizens Gas & Coke Utility – LNG North
Source Address: 4536 West 86th Street, Indianapolis, IN 46268
Mailing Address: 4536 West 86th Street, Indianapolis, IN 46268
FESOP No.: F097-18805-00141
Facility: Natural gas liquefaction compressor/heat exchange system for the liquefaction process (Emission Unit ID 01)
Parameter: VOC input, in tons, to the natural gas liquefaction compressor/heat exchange system – ethylene (VOC), in tons, sent to the natural gas distribution system = VOC emissions
Limit: Pursuant to 326 IAC 8-1-6, VOC input to the natural gas liquefaction compressor/heat exchange system shall be limited such that the potential to emit of VOC is less than ninety (90.0) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Quarter :_____ Year:_____

Month	Column 1	Column 2	Column 1 + Column 2
	VOC Emissions (tons) This Month	VOC Emissions (tons) Previous 11 Months	VOC Emissions (tons) 12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

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

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

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
and
CITY OF INDIANAPOLIS
OFFICE OF ENVIRONMENTAL SERVICES

FESOP Quarterly Report

Source Name: Citizens Gas & Coke Utility – LNG North
Source Address: 4536 West 86th Street, Indianapolis, IN 46268
Mailing Address: 4536 West 86th Street, Indianapolis, IN 46268
FESOP No.: F097-18805-00141
Facility: Allison simple cycle Gas Turbine, Emission Unit ID 01, the three T-Thermal water submerged Vaporizers, Emission Unit IDs 02 – 04, the Waukesha Emergency Generator, Emission Unit ID WEG 1, and the diesel fuel fired emergency fire pump, Emission Unit ID EFP-01
Parameter: NO_X emissions
Limit: Combined total Nitrogen Oxides (NO_X) emissions shall not exceed 93.06 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Quarter:_____ Year:_____

Month	Column 1	Column 2	Column 1 + Column 2
	Combined total Nitrogen Oxides (NO_X) emissions (tons) This Month	Combined total Nitrogen Oxides (NO_X) emissions (tons) Previous 11 Months	Combined total Nitrogen Oxides (NO_X) emissions (tons) 12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

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

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

Attach a signed certification to complete this report.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
and
CITY OF INDIANAPOLIS
OFFICE OF ENVIRONMENTAL SERVICES

FEDERALLY ENFORCEABLE STATE OPERATING PERMIT (FESOP)
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Citizens Gas & Coke Utility – LNG North
Source Address: 4536 West 86th Street, Indianapolis, IN 46268
Mailing Address: 4536 West 86th Street, Indianapolis, IN 46268
FESOP No.: F097-18805-00141

Months: _____ to _____ Year: _____

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked ANo deviations occurred this reporting period@.

☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.

☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Page 2 of 2

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed By: _____

Title/Position: _____

Date: _____

Phone: _____

Attach a signed certification to complete this report.

Indiana Department of Environmental Management
Office of Air Quality
and
City of Indianapolis
Office of Environmental Services

Addendum to the Technical Support Document
for a Federally Enforceable State Operating Permit (FESOP) Renewal

Source Background and Description

Source Name:	**Citizens Gas & Coke Utility – LNG North**
Source Location:	**4536 West 86th Street, Indianapolis, IN 46268**
County:	**Marion**
SIC Code:	**4922**
Operation Permit No.:	**F097-10018-00141**
Operation Permit Issuance Date:	**June 1, 1999**
Permit Renewal No.:	**F097-18805-00141**
Permit Reviewer:	**M. Caraher**

On November 14, 2006, the Office of Air Quality (OAQ) and the City of Indianapolis Office of Environmental Services (OES) had a notice published in the Indianapolis Star newspaper stating Citizens Gas & Coke Utility – LNG North (herein identified as Citizens Gas) had applied for a Federally Enforceable State Operating Permit (FESOP) Renewal relating to the operation of a liquefied natural gas storage plant. The FESOP Renewal includes a Best Available Control Technology (BACT) analysis for volatile organic compound emissions from the natural gas liquefaction compressor/heat exchange system. The notice also stated that OAQ and OES proposed to issue a permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice also informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

On December 14, 2006, Hatchett & Hauck, LLP, submitted written comments on the draft FESOP Renewal on behalf of Citizens Gas. The comments and responses, including changes to the permit, are listed below and on the following pages.

The Technical Support Document (TSD) will remain as it originally appeared when published. Changes to the permit or technical support material that occur after the draft permit has published for public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result of ensuring that these types of concerns are documented and part of the record regarding this permit decision. Bolded language has been added and the language with strikeout has been deleted.

Comment 1:

Condition D.1.2(a) – This condition is intended to limit volatile organic compound (VOC) emissions from the liquefaction process. In order to better clarify the applicability of this provision, Citizens Gas requests that this provision be reworded as follows:

"…VOC input shall be limited such that the potential to emit of VOC from the liquefaction process is less than ninety.."

Response to Comment 1:

The emission unit description in Condition A.2(a) and Section D.1 identify the natural gas liquefaction compressor/heat exchange system as the process from which VOC emissions are expected to occur. Condition D.1.2(b) and Condition D.1.7(b)(1) identify the natural gas liquefaction compressor/heat exchange system as the specific process for which VOC input is limited and recorded. In order to consistently identify the process for which VOC input is limited and recorded, the following revision was made to Condition D.1.2(a) and the FESOP Quarterly Report Form for VOC emissions from the natural gas liquefaction compressor/heat exchange system:

D.1.2 Volatile Organic Compounds (VOC) [326 IAC 8-1-6]

(a) Pursuant to 326 IAC 8-1-6, VOC input **to the natural gas liquefaction compressor/heat exchange system** shall be limited such that the potential to emit of VOC is less than ninety (90.0) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) Ethylene (VOC) input not sent to the natural gas liquefaction compressor/heat exchange system from Emission Unit ID Ethylene Storage Tank shall only be vented into the vapor feed line directly into the natural gas distribution system.

***

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE DATA SECTION
and
CITY OF INDIANAPOLIS
OFFICE OF ENVIRONMENTAL SERVICES

FESOP Quarterly Report

Source Name:	Citizens Gas & Coke Utility – LNG North
Source Address:	4536 West 86th Street, Indianapolis, IN 46268
Mailing Address:	4536 West 86th Street, Indianapolis, IN 46268
FESOP No.:	F097-18805-00141
Facility:	Natural gas liquefaction compressor/heat exchange system for the liquefaction process (Emission Unit ID 01)
Parameter:	VOC input, in tons, **to the natural gas liquefaction compressor/heat exchange system** – ethylene (VOC), in tons, sent to the natural gas distribution system = VOC emissions
Limit:	Pursuant to 326 IAC 8-1-6, VOC input **to the natural gas liquefaction compressor/heat exchange system** shall be limited such that the potential to emit of VOC is less than ninety (90.0) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Comment 2:

Condition D.1.10 – This condition incorporates New Source Performance Standards (NSPS) which are applicable to the gas turbine. Citizens Gas believes the formula copied from NSPS 60.332(a)(2) [on page 30 of the proposed permit] is incorrect. It should be “STD = 0.0150(14.4)/Y + F”.

Response to Comment 2:

40 CFR 63.332(a)(2) and 40 CFR 63.332(c) were each correctly stated as applicable requirements in the public notice permit. However, the equation was incorrectly stated. Pursuant to 40 CFR 63.332(c), the equation for nitrogen oxides emissions from stationary gas turbines that are not electric utility stationary gas turbines is stated in 40 CFR 63.332(a)(2). Therefore, the equation should have stated 0.0150 as a multiplier instead of 0.0075. Condition D.1.10 is revised as follows:

D.1.10 Standards of Performance for Stationary Gas Turbines [40 CFR 60.330 Subpart GG] [326 IAC 12]

Pursuant 40 CFR 60.330 Subpart GG (Standards of Performance for Stationary Gas Turbines), the one (1) Allison simple cycle Gas Turbine, identified as Emission Unit ID 01, shall comply with the following:

***

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

STD = **0.0150**~~0.0075~~(14.4)/Y + F

Comment 3:

Condition D.1.11 – This condition incorporates NSPS language that is applicable to the vaporizers. The rule language from 60.48c(g) [on page 40 of the permit] does not include additional language added earlier this year allowing the use of monthly records for certain sources (including sources which burn natural gas). Citizens Gas requests that this language be added to the permit.

Response to Comment 3:

On February 27, 2006, U. S. EPA revised 40 CFR 60.40c, Subpart Dc, to eliminate the daily record keeping requirement for natural gas fuel consumption in affected emission units. However, the Indiana Air Pollution Control Board has not completed rule making to adopt these changes. Therefore, the T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04 are still subject to 40 CFR Part 60.40c, Subpart Dc (July 1, 2002 version) and 326 IAC 12. The public notice permit did include 40 CFR 60.40c, July 1, 2002 version, in Condition D.1.11. The public notice permit should have additionally included 40 CFR 60.40c, as revised on February 27, 2006, because it is an existing federally enforceable applicable requirement. Therefore, existing Condition D.1.11 requirements are revised to include 40 CFR 60.40c, as revised on February 27, 2006. The condition title and the first and second sentence of the existing Condition D.1.11 (State Only Heat Transfer Medium NSPS Requirements) are moved to new Condition D.1.12 and Condition D.1.11 is revised as follows:

D.1.11 Standards of Performance for Small Industrial-Commercial-Intstitutional Steam Generating Units [40 CFR 60.40c, Subpart Dc]

Pursuant 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Intstitutional Steam Generating Units), the three T-Thermal water submerged Vaporizers, identified as Emission Unit ID 02, 03 and 04, shall each comply with the following:

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, §60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in §60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under §60.14.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see §60.17), coal refuse, and petroleum coke. **Coal-derived synthetic** ~~Synthetic~~ fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Cogeneration steam generating unit means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (i.e., the heat generated is released to

the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396–78, 89, 90, 92, 96, or 98, “Standard Specification for Fuel Oils” (incorporated by reference—see §60.17).

Dry flue gas desulfurization technology means a sulfur dioxide (SO_2) control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under §60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR Parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835–86, 87, 91, or 97, “Standard Specification for Liquefied Petroleum Gases” (incorporated by reference—see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule [ng/J], or pounds per million Btu [lb/million Btu] heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396–78, 89, 90, 92, 96, or 98, "Standard Specification for Fuel Oils" (incorporated by reference—see §60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of particulate matter (PM) or SO_2.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000; **71 FR 9884, Feb. 27, 2006]**

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as

an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. **The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month.**

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000; **71 FR 9884, Feb. 27, 2006]**

D.1.**12**~~11~~ State Only Heat Transfer Medium NSPS Requirements [326 IAC 12]

Pursuant 326 IAC 12, the Permittee shall comply with the provisions of the July 1, 2002 version of 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial-Commercial-Intstitutional Steam Generating Units), which is incorporated by reference by 326 IAC 12 for **each of** the T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04. The Permittee shall comply with the following:

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

***Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388–77, 90, 91, 95, or 98a, Standard Specification for Classification of Coals by Rank (IBR—see §60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.**

[55 FR 37683, Sept. 12, 1990, as amended at 61 FR 20736, May 8, 1996; 65 FR 61752, Oct. 17, 2000]

§ 60.48c Reporting and recordkeeping requirements.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

[55 FR 37683, Sept. 12, 1990, as amended at 64 FR 7465, Feb. 12, 1999; 65 FR 61753, Oct. 17, 2000]

The requirements of 326 IAC 12 listed in this condition are not federally enforceable.

Indiana Department of Environmental Management
Office of Air Quality
and
City of Indianapolis
Office of Environmental Services

Technical Support Document (TSD) for a Federally Enforceable State Operating Permit (FESOP) Renewal

Source Background and Description

Source Name:	**Citizens Gas & Coke Utility – LNG North**
Source Location:	**4536 West 86th Street, Indianapolis, IN 46268**
County:	**Marion**
SIC Code:	**4922**
Operation Permit No.:	**F097-10018-00141**
Operation Permit Issuance Date:	**June 1, 1999**
Permit Renewal No.:	**F097-18805-00141**
Permit Reviewer:	**M. Caraher**

The Office of Air Quality (OAQ) and the City of Indianapolis Office of Environmental Services (OES) have reviewed a FESOP Renewal application from Citizens Gas & Coke Utility – LNG North (herein identified as Citizens Gas) relating to the operation of a liquefied natural gas storage plant.

In addition, Citizens Gas requested to change existing Condition D.1.4 (Volatile Organic Compounds) of F097-10018-00141 which limited VOC emissions from the natural gas liquefaction process to less than twenty four (24) tons per year such that 326 IAC 8-1-6 (General Provisions Relating to VOC Rules: General Reduction Requirements for New Facilities) does not apply. Citizens Gas requested that the limit on VOC emissions from the natural gas liquefaction process be changed from less than twenty-four (24) tons per year to less than ninety (90) tons per year. Citizens Gas submitted a Best Available Control Technology (BACT) analysis with the FESOP Renewal application in order to satisfy the requirements of 326 IAC 8-1-6 (General Provisions Relating to VOC Rules: General Reduction Requirements for New Facilities).

Permitted Emission Units and Pollution Control Equipment

The source consists of the following permitted emission units and pollution control devices:

(a) One (1) Allison simple cycle Gas Turbine for refrigerant compressor, identified as Emission Unit ID 01 and exhausting at Stack/Vent ID S01. Natural gas fired at 38.0 million Btu per hour maximum heat input. Model number 501-KC5. Installation date of 1990. Under 40 CFR 60.330, Subpart GG (Standards of Performance for Stationary Gas Turbines), the Allison simple cycle Gas Turbine is considered a stationary gas turbine. Emission Unit ID 01 includes non HAP VOC emissions from the natural gas liquefaction compressor/heat exchange system.

(b) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 02 and exhausting at Stack/Vent ID 02-A1 and 02-A2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 02 is considered a steam generating unit.

(c) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 03 and exhausting at Stack/Vent ID 03-B1 and 03-B2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 03 is considered a steam generating unit.

(d) One (1) T-Thermal water submerged Vaporizer for the vaporization of liquefied natural gas, identified as Emission Unit ID 04 and exhausting at Stack/Vent ID 04-C1 and 04-C2. Includes six (6) natural gas fired burners with a combined total heat input capacity of 72.0 million Btu per hour. Installation date of 1990. Under 40 CFR 60.40c, Subpart Dc (Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units), the T-Thermal water submerged Vaporizer identified as Emission Unit ID 04 is considered a steam generating unit.

Unpermitted Emission Units and Pollution Control Equipment

There are no unpermitted emission units operating at this source during this review process.

Insignificant Activities

The source also consists of the following insignificant activities, as defined in 326 IAC 2-7-1(21):

(a) Natural gas-fired combustion sources with heat input equal to or less than ten (10) million BTU per hour:

(1) Salt Bath heater for mole sieve regeneration, operated while natural gas is being liquefied, identified as Emission Unit ID SBH-01, with a maximum heat input capacity of 6.5 MMBtu/hr. [326 IAC 6-2-4]

(b) Activities associated with the treatment of wastewater streams with an oil and grease content less than or equal to 1% by volume.

(c) Process vessel degassing and cleaning to prepare for internal repairs.

(d) Purging of gas lines and vessels that is related to routine maintenance and repair of buildings, structures, or vehicles at the source where air emissions from those activities would not be associated with any production process.

(e) Equipment used to collect any material that might be released during a malfunction, process upset or spill cleanup including catch tanks, temporary liquid separators, tanks and fluid handling equipment.

(f) On site fire and emergency response training approved by the department.

(g) Natural gas turbines or reciprocating engines not exceeding 16,000 horsepower, including:

(1) Emission Unit ID WEG 1, Waukesha Emergency Generator, natural gas fired at 6.0 million Btu per hour or an equivalent horsepower rating of 2346 at 1750 kilowatts. [326 IAC 2-3]

(h) Stationary fire pumps, including:

(1) Emission Unit ID EFP-01, diesel fuel fired emergency fire pump, rated at 459 horse power. [326 IAC 2-3]

(i) Purge double block and bleed valves.

(j) One (1) ethylene storage tank at 12,000 gallon storage capacity, identified as Emission Unit ID Ethylene Storage Tank, installed in 1990. [326 IAC 8-1-6]

(k) One (1) pentane storage tank at 10,000 gallon storage capacity, identified as Emission Unit ID Pentane Storage Tank, installed in 1990.

(l) One (1) butane storage tank and one (1) propane storage tank, identified as Emission Unit ID Butane Storage Tank, and Emission Unit ID Propane Storage Tank, respectively, each at 3,500 gallon storage capacity, and one (1) odorant storage tank at 100 gallon capacity, all installed in 1990.

Existing Approvals

The source has constructed or has been operating under the following previous approvals:

(a) FESOP 097-10018-00141, issued on June 1, 1999; and

(b) Permit re-opening R097-13079-00141, issued on February 7, 2002.

All terms and conditions of previous permits issued pursuant to permitting programs approved into the state implementation plan have been either incorporated as originally stated, revised, or deleted by this permit. All previous registrations and permits are superseded by this permit.

The following applicable requirements from terms and conditions of previous approvals have been revised or deleted in this FESOP Renewal (deletions in ~~strikeout~~ and revisions in **bold**):

Change 1: Condition B.10 (Compliance with Permit Conditions) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason not incorporated in Section B – General Conditions: The provisions of 326 IAC 2-8-4(5)(A) and 326 IAC 2-8-4(5)(B) have been moved to the Title Page for this FESOP Renewal, F097-18805-00141. Therefore, Condition B.10 is deleted from Section B – General Conditions as follows (which causes the subsequent renumbering of all remaining Section B conditions):

~~B.10 Compliance with Permit Conditions [326 IAC 2-8-4(5)(A)] [326 IAC 2-8-4(5)(B)]~~

~~(a) The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit constitutes a violation of the Clean Air Act and is grounds for:~~

~~(1) Enforcement action:~~

~~(2) Permit termination, revocation and reissuance, or modification; and~~

~~(3) Denial of a permit renewal application.~~

~~(b) It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.~~

Change 2: Condition B.13 (Preventive Maintenance Plan) and Condition B.14 (Emergency Provisions) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason each condition is revised: IDEM's Office of Air Management (OAM) has been renamed Office of Air Quality (OAQ) and the City of Indianapolis Environmental Resources Management Division (ERMD) has been renamed the Office of Environmental Services (OES). In addition, the OAQ mail address has changed. To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, IDEM and OES have determined that such a Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit. IDEM and OES have also determined that the Permittee is not required to keep records of all preventive maintenance. However, where the Permittee seeks to demonstrate that an emergency has occurred, the Permittee must provide, upon request, records of preventive maintenance in order to establish that the lack of proper maintenance did not cause or contribute to the deviation. Therefore, IDEM and OES have deleted paragraph (b) of Section B.**11**~~13~~ – Preventive Maintenance Plan, and have amended the Section B.**12**~~14~~ – Emergency Provisions condition as follows:

B.**11**~~13~~ Preventive Maintenance Plan [326 IAC 1-6-3] [326 IAC 2-8-4(9)] [326 IAC 2-8-5(a)(1)]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) within ninety (90) days after issuance of this permit, including the following information on each facility:-

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

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

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

~~If due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the above time frame, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:~~

~~Indiana Department of Environmental Management~~
~~Compliance Branch, Office of Air Quality~~
~~100 North Senate Avenue~~
~~Indianapolis, Indiana 46204~~

~~and~~

~~Indianapolis Office of Environmental Services~~
~~Air Compliance~~
~~2700 South Belmont Avenue~~
~~Indianapolis, IN 46221~~

~~The PMP extension notification does not require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).~~

~~(b)~~ ~~The Permittee shall implement the PMPs, including any required record keeping as necessary to ensure that failure to implement a PMP does not cause or contribute to an exceedance of any limitation on emissions or potential to emit.~~

~~(c)~~ **(b) A copy of the** PMPs shall be submitted to IDEM, **OAQ** ~~OAM~~, and **OES** ~~ERMD~~ upon request **and within a reasonable time,** and shall be subject to review and approval by IDEM, **OAQ** ~~OAM~~ and **OES** ~~ERMD~~. **IDEM, OAQ and OES may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions or potential to emit. The PMPs do not require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).**

(c) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B. **12**~~14~~ Emergency Provisions [326 IAC 2-8-12]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation, except as provided in 326 IAC 2-8-12.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a health-based or technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describes the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, **OAQ** ~~OAM~~, and **OES** ~~ERMD~~, within four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

~~IDEM, OAM~~
Telephone No.: 1-800-451-6027 (ask for **IDEM, OAQ** ~~Office of Air Management~~, Compliance Section) or,
Telephone No.: 317-233-0178 (ask for **IDEM, OAQ,** Compliance Section)
Facsimile No.: 317-233-6865

and

City of Indianapolis OES ~~ERMD~~
Telephone No.: 317-327-2234 **(ask for OES Air Compliance Section)**
Facsimile No.: 317-327-2274

~~Failure to notify IDEM, OAM and ERMD, by telephone or facsimile within four (4) daytime business hours after the beginning of the emergency, or after the emergency is discovered or reasonably should have been discovered, shall constitute a violation of 326 IAC 2-8 and any other applicable rules. [326 IAC 2-8-12(f)]~~

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air **Quality** ~~Management~~
100 North Senate Avenue~~, P.O. Box 6015~~
Indianapolis, Indiana **46206-6015** ~~46204~~

and

Indianapolis Office of Environmental Services
~~Environmental Resources Management Division~~
~~Air Quality Management Section, Compliance Data~~
Air Compliance
2700 South Belmont Avenue
Indianapolis, IN 46221

within two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-8-4(3)(C)(ii) and must contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require the certification by the “authorized individual” as defined by 326 IAC 2-1.1-1(1).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions) ~~for sources subject to this rule after the effective date of this rule~~. This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) **The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However,** IDEM, **OAQ** ~~OAM~~, and **OES** ~~ERMD~~, may require that the Preventive Maintenance Plans required under 326 IAC 2-8-3(c)(6) be revised in response to an emergency.

(f) Failure to notify IDEM, **OAQ** ~~OAM~~, and **OES** ~~ERMD~~, by telephone or facsimile of an emergency lasting more than one (1) hour in **compliance** ~~accordance~~ with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-8 and any other applicable rules.

(g) Operations may continue during an emergency only if the following conditions are met:

(1) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

(2) If an emergency situation causes a deviation from a health-based limit, the Permittee may not continue to operate the affected emissions facilities unless:

(A) The Permittee immediately takes all reasonable steps to correct the emergency situation and to minimize emissions; and

(B) Continued operation of the facilities is necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw material of substantial economic value.

Any operations shall continue no longer than the minimum time required to prevent the situations identified in (g)(2)(B) of this condition.

(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report.

Change 3: Condition B.19 (Changes Under Section 502(b)(10) of the Clean Air Act) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason not incorporated: The Permit condition for changes under Section 502(b)(10) of the Clean Air Act has been moved to Condition B.**19**~~20~~(b) (Operational Flexibility) for this FESOP Renewal, F097-18805-00141. Therefore, Condition B.19 (Changes Under Section 502(b)(10) of the Clean Air Act) of FESOP 097-10018-00141 is deleted as follows (which causes the subsequent renumbering of all remaining Section B conditions):

~~B.19 Changes Under Section 502(b)(10) of the Clean Air Act [326 IAC 2-8-15(b)]~~

~~The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-8-15(a) and the following additional condition:~~

~~For each such change, the required written notification shall include a brief description of the change within the source, the date on which the change will occur, any changes in emissions, and any permit term or condition that is no longer applicable as a result of the change.~~

Change 4: Condition B.20 (Operational Flexibility) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason revised: IDEM, OAQ and OES have clarified the Condition B.**19**~~20~~ (Operational Flexibility) condition as follows:

B.**19**~~20~~ Operational Flexibility [326 IAC 2-8-15] **[326 IAC 2-8-11.1]**

(a) The Permittee may make any change or changes at this source that are described in 326 IAC 2-8-15(b) through (d) without prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any **preconstruction** approval required by **326 IAC 2-8-11.1** ~~326 IAC 2-1.1~~ has been obtained;

(3) The changes do not result in emissions which exceed the **limitations provided in** ~~emissions allowable under~~ this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permits Branch, Office of Air **Quality** ~~Management~~
100 North Senate Avenue~~, P.O. Box 6015~~
Indianapolis, Indiana **46204-2251** ~~46206~~

and

City of Indianapolis
Office of Environmental Services
~~Environmental Resources Management Division~~
Air Quality Management Section~~, Permits~~
2700 South Belmont Avenue
Indianapolis Indiana 46221-2097

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site**, on a rolling five (5) year basis,** which document~~, on a rolling five (5) year basis,~~ all such changes and emission~~s~~ ~~trading~~ **trades** that are subject to 326 IAC 2-8-15(b) through (d) ~~and makes~~ **The Permittee shall make** such records available, upon reasonable request, to public review.

Such records shall consist of all information required to be submitted to IDEM, **OAQ** ~~OAM~~ and ~~the~~ **OES** ~~ERMD~~, in the notices specified in 326 IAC 2-8-15(b)(2), (c)(1), and (d).

~~(b) For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:~~

~~(1) A brief description of the change within the source;~~

~~(2) The date on which the change will occur;~~

~~(3) Any change in emissions; and~~

~~(4) Any permit term or condition that is no longer applicable as a result of the change.~~

(b) ~~(c)~~ Emission Trades [326 IAC 2-8-15(c)]
The Permittee may trade **emissions** increases and decreases **at** ~~in emissions in~~ the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-8-15(c).

(c) ~~(d)~~ Alternative Operating Scenarios [326 IAC 2-8-15(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that are described in the terms and conditions of this permit in accordance with 326 IAC 2-8-4(7). No prior notification of IDEM, **OAQ** ~~OAM~~ or U.S. EPA is required.

(d) ~~(e)~~ Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

Change 5: Condition C.2 (Particulate Matter Limitations For Processes with Process Weight Rate Less Than One Hundred (100) Pounds per Hour) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason revised: The 326 IAC 6-3 rule revisions that became effective on June 12, 2002 were approved into the State Implementation Plan on September 23, 2005. These rules replace the previous version of 326 IAC 6-3 (Process Operations) that had been part of the SIP. Therefore, the requirements of the previous version of 326 IAC 6-3-2 are no longer applicable to this source. Condition C.2 has been revised to remove (c), which contained these requirements. Particulate emission limitations for processes with process weight rates less than one hundred (100) pounds per hour that are not exempted by 326 IAC 6-3-1(b) or (c) and are not subject to the provisions of 326 IAC 6-3-2(b) through (d), are subject to 326 IAC 6-3-2(e)(2). Therefore, Condition C.**1**~~2~~ (Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour) is revised as follows:

C.**1**~~2~~ Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2~~(c)~~]

Pursuant to 326 IAC 6-3-2**(e)(2)**~~(c)~~, particulate emissions ~~rate~~ from any process not ~~already regulated by 326 IAC 6-1 or any New Source Performance Standard,~~ exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour **and the methods in 326 IAC 6-3-2(b) through (d) do not apply** shall not exceed 0.551 pounds per hour.

Change 6: C.8 (Asbestos Abatement Projects) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason revised: A shorter version stating the applicable requirements for asbestos abatement projects was requested by Citizens Gas and is revised as follows:

C.~~7~~8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140.

~~(a) Notification requirements apply to each owner or operator. If the combined amount of regulated asbestos containing material (RACM) to be stripped, removed or disturbed is at least 260 linear feet on pipes or 160 square feet on other facility components, or at least thirty-five (35) cubic feet on all facility components, then the notification requirements of 326 IAC 14-10-3 are mandatory. All demolition projects require notification whether or not asbestos is present.~~

~~(b) The Permittee shall ensure that a written notification is sent on a form provided by the Commissioner at least ten (10) working days before asbestos stripping or removal work or before demolition begins, per 326 IAC 14-10-3, and shall update such notice as necessary, including, but not limited to the following:~~

~~(1) When the amount of affected asbestos containing material increases or decreases by at least twenty percent (20%); or~~

~~(2) If there is a change in the following:~~

~~(A) Asbestos removal or demolition start date;~~

~~(B) Removal or demolition contractor; or~~

~~(C) Waste disposal site.~~

~~(c) The Permittee shall ensure that the notice is postmarked or delivered according to the guidelines set forth in 326 IAC 14-10-3(2).~~

~~(d) The notice to be submitted shall include the information enumerated in 326 IAC 14-10-3(3).~~

~~All required notifications shall be submitted to:~~

~~Indiana Department of Environmental Management
Asbestos Section, Office of Air Quality
100 North Senate Avenue
Indianapolis, Indiana 46204~~

~~and~~

~~Indianapolis Office of Environmental Services
Asbestos Section
2700 South Belmont Avenue
Indianapolis, IN 46221~~

~~The notice shall include a signed certification from the owner or operator that the information provided in this notification is correct and that only Indiana licensed workers and project supervisors will be used to implement the asbestos removal project. The notifications do not require a certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).~~

~~(e) Procedures for Asbestos Emission Control~~
~~The Permittee shall comply with the applicable emission control procedures in 326 IAC 14-10-4 and 40 CFR 61.145(c). Per 326 IAC 14-10-1 emission control requirements are applicable for any removal or disturbance of RACM greater than three (3) linear feet on pipes or three (3) square feet on any other facility components or a total of at least 0.75 cubic feet on all facility components.~~

~~(f) Demolition and renovation~~
~~The Permittee shall thoroughly inspect the affected facility or part of the facility where the demolition or renovation will occur for the presence of asbestos pursuant to 40 CFR 61.145(a).~~

~~(g) Indiana Accredited Asbestos Inspector~~
~~The Permittee shall comply with 326 IAC 14-10-1(a) that requires the owner or operator, prior to a renovation/demolition, to use an Indiana Accredited Asbestos Inspector to thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Accredited Asbestos inspector is not federally enforceable.~~

Change 7: Condition C.13 (Compliance Monitoring Plan – Failure to Take Response Steps) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason revised: IDEM and OES have reconsidered the requirement to develop and follow a Compliance Response Plan. The Permittee will still be required to take reasonable response steps when a compliance monitoring parameter is determined to be out of range or abnormal. Replacing the requirement to develop and follow a Compliance Response Plan with a requirement to take reasonable response steps will ensure that the control equipment is returned to proper operation as soon as practicable, while still allowing the Permittee the flexibility to respond to situations that were not anticipated. The Section D conditions that refer to this condition have been revised to reflect the new condition title, and the following changes have been made to the Section C condition:

C.13 ~~Compliance Monitoring Plan - Failure to Take Response Steps~~ **Response to Excursions or Exceedances** [326 IAC 2-8-4][326 IAC 2-8-5]

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

~~(1) This condition;~~

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

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

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

~~(5) A Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. CRP's shall be submitted to IDEM, OAM and ERMD upon request and shall be subject to review and approval by IDEM, OAM and ERMD. The CRP shall be prepared within ninety (90) days after issuance of this permit by the Permittee and maintained on site, and is comprised of:~~

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

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

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

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

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

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

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

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

~~(d) Records shall be kept of all instances in which the compliance related information was not met and of all response steps taken. In the event of an emergency, the provisions of 326 IAC 2-7-16 (Emergency Provisions) requiring prompt corrective action to mitigate emissions shall prevail.~~

(a) Upon detecting an excursion or exceedance, the Permittee shall restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Corrective actions may include, but are not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not limited to, the following:

(1) monitoring results;

(2) review of operation and maintenance procedures and records;

(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall maintain the following records:

(1) monitoring data;

(2) monitor performance data, if applicable; and

(3) corrective actions taken.

Change 8: Condition C.15 (Emission Statement) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason not incorporated: Rule revisions to 326 IAC 2-6 (Emission Reporting) became effective March 27, 2004. Due to the revision to the state rule, this source is no longer subject to 326 IAC 2-6-1(a) (Emission Reporting) because it is located in Marion County, it does not have an operating permit under 326 IAC 2-7 (Part 70 Permit Program), and it does not emit lead into the ambient air at levels equal to or greater than five (5) tons per year. Therefore, the emission reporting requirement of 326 IAC 2-6 (Emission Reporting) is not incorporated into the FESOP Renewal, 097-19373-00141, for this source to reflect the March 27, 2004 rule revisions and is deleted as follows (which causes the subsequent renumbering of all remaining Section C conditions):

~~C.15 Emission Statement [326 IAC 2-6] [326 IAC 2-8-4(3)]~~

~~(a) The Permittee shall submit an annual emission statement certified pursuant to the requirements of 326 IAC 2-6, that must be received by April 15 of each year and must comply with the minimum requirements specified in 326 IAC 2-6-4. The submittal should cover the period defined in 326 IAC 2-6-2(8) (Emission Statement Operating Year).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~~

~~and~~

~~Environmental Resources Management Division~~
~~Air Quality Management Section, Compliance Data~~
~~2700 South Belmont Avenue~~
~~Indianapolis Indiana 46221~~

~~(b)~~ ~~The annual emission statement required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ, and ERMD on or before the date it is due.~~

Change 9: Condition D.2.2 of FESOP 097-10018-00141, issued on June 1, 1999.

Reason revised: The allowable particulate matter emission rate, pursuant to 326 IAC 6-2-4, has been revised to be consistent with the number of significant digits utilized in the equation. In addition, the Salt Bath heater for mole sieve regeneration, identified as Emission Unit ID SBH-01, is an indirect heating unit installed after September 21, 1983. Therefore, 326 IAC 6-2-4 is an applicable requirement for this Insignificant Activity. Condition D.2.2 of FESOP 097-10018-00141, issued on June 1, 1999 has been incorporated as Condition D.1.3 of the FESOP Renewal and is revised as follows:

D.**1.3**~~2.2~~ Particulate Matter (PM) [326 IAC 6-2-1][326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-1 (Particulate Emission Limitations for Sources of Indirect Heating), the allowable PM emission rate from **the three T-Thermal water submerged Vaporizers, identified as** Emission Unit ID~~s~~ 02, 03 and 04, **and the Salt Bath heater for mole sieve regeneration, identified as Emission Unit ID SBH-01, based on a total heat input rate of 222.50 MMBtu per hour**, ~~each shall not exceed the allowable PM emission rate as specified pursuant to 326 IAC 6-2-4 (Particulate Emissions for Facilities Specified in 326 IAC 6-2-1(c)) and stated below~~, **shall each be limited to 0.27 pound per MMBtu heat input.**

This limitation is based on the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

where: Pt = Pounds of particulate matter emitted per MMBtu heat input.
Q = Total source maximum operating capacity rating in MMBtu per hour.

~~For Q = 216 million Btu per hour (72.0 million Btu per hour for each of 3 Emission Unit ID's), Pt shall not exceed 0.3 pounds per million Btu.~~

Change 10: Condition D.2.3 and Condition D.3.2 of FESOP 097-10018-00141, issued on June 1, 1999.

Reason revised: The applicable NO_X pound per hour limit for the vaporizers in Installation Permit No. 900141-01, issued on November 6, 1990, is moved to Condition D.1.1 of this FESOP Renewal, 097-18805-00141. In addition, a NO_X emission limit in pounds per million cubic feet of natural gas burned is inserted in Condition D.1.1(b) in order to enforceably limit NO_X emissions such that 328 IAC 2-7 (Part 70 Permit Program) and 326 IAC (2-3) (Emission Offset) continue to not apply to the source (see discussion under State Rule Applicability). Citizens Gas specifically requested that the NO_X emissions from significant and insignificant activity emission units sum to, approximately, 95.0 tons per twelve consecutive month period. The revision is as follows:

~~D.2.3 Emission Offset Minor Limit [326 IAC 2-3][326 IAC 2-8-4]~~

~~Pursuant to Installation Permit number 900141-01, issued on November 6, 1990, each Emission Unit ID 02, 03, and 04 shall be limited to 11.1 pounds of NO_x per hour and shall be limited to a combined total 3.3 tons NO_x emissions per rolling twelve (12) consecutive month period. Pursuant to 326 IAC 2-8-4 (FESOP; Permit Content), Emission Unit ID 02, 03 and 04 are limited to a combined total of 43.2 million cubic feet of natural gas consumption per rolling twelve (12) consecutive month period. The natural gas consumption limitation is required to limit the potential to emit NO_x to less than 3.3 tons per rolling twelve (12) consecutive month period. Compliance with this limit makes 326 IAC 2-3 (Emission Offset and 326 IAC 2-7 (Part 70 Permit Program) not applicable.~~

~~D.3.2 Nitrogen Oxides (NO_x) [326 IAC 2-8-4]~~

~~Pursuant to 326 IAC 2-8-4 (FESOP; Permit Content):~~

~~(a) Emission Unit ID WEG-01 is limited to 3.0 million cubic feet of natural gas consumption per rolling twelve consecutive month period. This limitation is equivalent to 500 annual operating hours at maximum capacity.~~

~~(b) Emission Unit ID EFP-01 is limited to 4379 gallons per year of diesel fuel consumption per rolling twelve (12) consecutive month period. This limitation is equivalent to 500 annual operating hours at maximum capacity.~~

~~Compliance with this limit makes 326 IAC 2-3 (Emission Offset) and 326 IAC 2-7 (Part 70 Operating Permit Program) not applicable.~~

D.1.1 Emission Offset Minor Limit [326 IAC 2-3][326 IAC 2-8-4] **[Installation Permit 900141-01]**

(a) Pursuant to Installation Permit number 900141-01, issued November 6, 1990**:** ~~Emission Unit ID 01 shall be limited to 32.1 pounds of NOX emissions per hour and 83.6 tons of NOX per year. Pursuant to 326 IAC 2-8-4 (FESOP; Permit Content), Emission Unit ID 01 is limited to 197.6 million cubic feet of natural gas consumption per rolling twelve (12) consecutive month period and is limited to a nitrogen content for gas turbine fuel of 23.2 percent by weight. The natural gas consumption limitation and nitrogen content limitation of the fuel is required to limit the potential to emit NOX to less than 83.6 tons per rolling twelve (12) consecutive month period. Compliance with this limit makes 326 IAC 2-3 (Emission Offset) and 326 IAC 2-7 (Part 70 Operating Permit Program) not applicable~~

(1) Nitrogen Oxides (NO_X) emissions from Emission Unit ID 01, the one (1) Allison simple cycle Gas Turbine, shall be limited to 32.1 pounds per hour.

(2) The nitrogen content for gas turbine fuel consumed in Emission Unit ID 01, the one (1) Allison simple cycle Gas Turbine, shall be limited to 23.2 percent by weight.

(b) Pursuant to 326 IAC 2-8-4 (FESOP; Permit Content):

(1) Nitrogen Oxides (NO_X) emissions from the Allison simple cycle Gas Turbine, identified as Emission Unit ID 01, shall not exceed 846 pounds per million cubic feet (lbs/MMCF) of natural gas burned.

(2) Nitrogen Oxides (NO_X) emissions from each of the three T-Thermal water submerged Vaporizers, identified as Emission Unit ID 02, 03 and 04, shall

not exceed 100 pounds per million cubic feet (lbs/MMCF) of natural gas burned.

(3) Nitrogen Oxides (NO_X) emissions from the Waukesha Emergency Generator, identified as Emission Unit ID WEG 1, shall not exceed 3,170 pounds per million cubic feet (lbs/MMCF) of natural gas burned.

(4) Nitrogen Oxides (NO_X) emissions from the diesel fuel fired emergency fire pump, Emission Unit ID EFP-01, shall not exceed 0.6 pounds per gallon (lbs/gal) of diesel fuel burned.

(5) The combined total Nitrogen Oxides (NO_X) emissions from the Allison simple cycle Gas Turbine, Emission Unit ID 01, the three T-Thermal water submerged Vaporizers, Emission Unit IDs 02 – 04, the Waukesha Emergency Generator, Emission Unit ID WEG 1, and the diesel fuel fired emergency fire pump, Emission Unit ID EFP-01, shall not exceed 93.06 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Compliance with this condition shall limit total NO_X emissions from the source to less than 100 tons per twelve (12) consecutive month period with compliance determined at the end of each month and demonstrates compliance with 326 IAC 2-3 (Emission Offset) and Installation Permit number 900141-01, issued November 6, 1990. Therefore, the requirements of 326 IAC 2-7 (Part 70) and 326 IAC 2-3 (Emission Offset) do not apply to the source.

Change 11: Condition D.1.4 of FESOP 097-10018-00141, issued on June 1, 1999.

Reason for the revision: The City of Indianapolis OES issued a Notice of Violation (NOV) on February 17, 2004 to Citizens Gas for violation of Condition D.1.4 for the period of February 2003 through December 2003. IDEM, OAQ issued a NOV to Citizens Gas on July 14, 2005 for violation of Condition D.1.4 and 326 IAC 8-1-6 based on the evidence stated in the City of Indianapolis' NOV. IDEM, OAQ resolved the July 14, 2005 NOV on August 1, 2005. As a result of the IDEM resolution of the July 14, 2005 NOV, OES rescinded the February 17, 2004 NOV on August 1, 2005. As a result of these two (2) NOV's, Citizens Gas requested to change the existing limit of twenty four (24) tons per year of VOC emissions from the liquefaction process to less than ninety (90) tons per year of VOC. Citizens Gas requested this change because actual VOC losses from the liquefaction process had been underestimated in the initial FESOP review. Therefore, Citizens Gas has submitted a Best Available Control Technology (BACT) analysis pursuant to 326 IAC 8-1-6 as part of the FESOP Renewal application. Based on the application and BACT analysis (see TSD Appendix B), Condition D.1.**24** is revised as follows:

D.1. **24** Volatile Organic Compounds (VOC) [326 IAC 8-1-6]

~~Fugitive volatile organic compound (VOC) emissions from Emission Unit ID 01, which includes the gas liquefaction compressor/heat exchange system are limited to 24.0 tons per rolling twelve (12) consecutive month period such that 326 IAC 8-1-6 (Volatile Organic Compound Rules: New Facilities; General Reduction Requirements) does not apply~~.

(a) Pursuant to 326 IAC 8-1-6, VOC input shall be limited such that the potential to emit of VOC is less than ninety (90.0) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) Ethylene (VOC) input not sent to the natural gas liquefaction compressor/heat exchange system from Emission Unit ID Ethylene Storage Tank shall only be vented into the vapor feed line directly into the natural gas distribution system.

Change 12: Conditions D.3.1 and D.3.4(a) of FESOP 097-10018-00141, issued on June 1, 1999.

Reason not incorporated: The one (1) 12,000 gallon ethylene storage tank, identified as Emission Unit ID Ethylene Storage Tank, had been subject to the record keeping requirements of the New Source Performance Standard, 40 CFR 60.110b, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984), because the storage tank is a volatile organic liquid storage tank for which construction, modification or reconstruction commenced after July 23, 1984 and the storage tank has a capacity greater than 40 cubic meters (10,568 gallons). On October 15, 2003, U. S. EPA amended 40 CFR 60.110b to eliminate the record keeping requirement for storage vessels with a capacity less than 75 cubic meters (19,815 gallons). In the March 1, 2005 Indiana Register, the Indiana Air Pollution Control Board published a Proposed Rule Notice to adopt in 326 IAC 1-1-3 (CFR References) the July 1, 2004 Code of Federal Regulations (CFR) version in order to incorporate all Federal Rule revisions in CFR through July 1, 2004. The proposed rule became effective November 13, 2005. Therefore, the Ethylene Storage Tank is no longer subject to 40 CFR Part 60, Subpart Kb and 326 IAC 12. Therefore, Conditions D.3.1 and D.3.4(a) of FESOP 097-10018-00141, issued on June 1, 1999 are deleted as follows:

~~D.3.1 General Provisions Relating to NSPS [326 IAC 12-1] [40 CFR Part 60, Subpart A]~~

~~The provisions of 40 CFR Part 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to Emission Unit ID Ethylene Storage Tank as described in this section except when otherwise specified in 40 CFR Part 60, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984).~~

~~D.3.4 Record Keeping Requirements~~

~~(a) Pursuant to the New Source Performance Standard 40 CFR Part 60.116b Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984, the Permittee shall keep readily accessible records showing the dimension or tank capacity of Emission Unit ID Ethylene Storage Tank. This record shall be kept for the life of the source.~~

Change 13: Semi-annual reporting forms of FESOP 097-10018-00141, issued on June 1, 1999.

Reason for the revision: IDEM, OAQ and OES have the authority to require quarterly reports. At a minimum, reports must be submitted at least every six months under 326 IAC 2-7-5(3)(C)(i). However, IDEM, OAQ and OES believe that a period of time longer than every quarter will usually not provide sufficient reporting of continuous compliance. Therefore, the semi-annual reporting requirement for VOC emissions is changed from semi-annual reporting to quarterly reporting to coincide with other quarterly reporting already required and to provide sufficient reporting of continuous compliance.

Enforcement Issue

There are no enforcement actions pending.

Recommendation

The staff recommends to the Administrator that the FESOP Renewal be approved. This recommendation is based on the following facts and conditions:

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

An administratively complete FESOP Renewal application for the purposes of this review was received on August 26, 2003, at least nine (9) months in advance of the June 1, 2004 expiration date of the existing FESOP for this source, 097-10018-00141. Additional information was received on March 9, 2004, April 12, 2004, May 28, 2004, September 14, 16 and 20, 2004, October 18, 2004, December 10 and 20, 2004, October 24, 2005 and December 21, 2005. A plant tour of the liquefaction process was conducted on August 2, 2005. Additional information was also received on September 9, and 22, 2006.

Emission Calculations

See Appendix A (pages 1 through 7 of 7) of this document for detailed emission calculations.

Unrestricted Potential Emissions

This table reflects the unrestricted potential emissions of the source, excluding the emission limits that were contained in the previous FESOP.

Pollutant	Unrestricted Potential Emissions (tons/yr)
PM	3.06
PM-10	8.65
SO_2	1.20
VOC	98.47
CO	95.79
NO_x	244.31

HAPs	Unrestricted Potential Emissions (tons/yr)
Hexane	1.75
Formaldehyde	0.27
Total	Less than 25

Note: Hexane and Formaldehyde are the highest single HAP emissions. See Appendix A.

The unrestricted potential emissions of nitrogen oxides (NO_X) are equal to or greater than one hundred (100) tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7. The source will be issued a FESOP Renewal because the source will continue to limit its NO_X emissions below the Part 70 Operating Permit Program levels.

Potential to Emit After Issuance

The source has opted to remain a FESOP source. The table below summarizes the potential to emit, reflecting all limits of the emission units. Any control equipment is considered enforceable only after issuance of this FESOP and only to the extent that the effect of the control equipment is made practically enforceable in the permit. Since the source has not constructed any new emission units, the source's potential to emit is based on the emission units included in the original FESOP and the revision to VOC emission losses from the liquefaction process.

	Potential To Emit (tons/year)						
Process/emission unit	PM	PM-10	SO_2	VOC	CO	NO_x	HAPs
Allison Turbine, Emission Unit ID 01 (includes VOC losses from liquefaction process & Ethylene Storage Tank)	1.10	1.10	0.53	91.83 [1]	13.65		0.12 / 0.17
Three Vaporizers, Emission Unit ID 02-04	1.80	7.19	0.57	5.20	79.47	93.06 [2]	1.70 / 1.79
Emergency Generator, Emission Unit ID WEG 1	0.01	0.06	0.00	0.18	0.00		0.08 / 0.12
Fire Pump, Emission Unit ID EFP-01	0.09	0.09	0.08	0.11	0.28		0.00 / 0.00
Salt Bath Heater, Emission Unit ID SBH-01	0.05	0.22	0.02	0.16	2.39	2.85	0.05 / 0.05
Insignificant Activity (Pentane & Butane Storage Tanks)	Negl.	Negl.	Negl.	0.99	Negl.	Negl.	Negl.
Total Emissions	3.06	8.65	1.2	98.47	95.79	95.91	1.75 / 2.12 [3]

1. Sum total VOC = PTE VOC from fuel combustion in Allison Turbine + 326 IAC 8-1-6 limit for VOC loss from the entire liquefaction process (see TSD Appendix A page 1 of 7).
2. Limited PTE based on NO_X emissions cap of 93.06 tons per year (see TSD Appendix A page 1 of 7).
3. Largest single HAP is hexane (see TSD Appendix A page 1 of 7).

County Attainment Status

The source is located in Marion County.

Pollutant	Status
PM-10	Unclassifiable
PM2.5	Nonattainment
SO_2	Maintenance attainment
NO_2	Attainment
8-hour Ozone	Basic nonattainment
CO	Attainment
Lead	Unclassifiable

(a) Volatile organic compounds (VOC) and Nitrogen Oxides (NO_X) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NO_X emissions are considered when evaluating the rule applicability relating to the ozone standards. Marion County has been designated as nonattainment of the 8-hour ozone standard. Therefore, VOC and NO_X emissions were reviewed pursuant to the requirements for Emission Offset, 326 IAC 2-3.

(b) Marion County has been classified as nonattainment for PM2.5 in 70 FR 943 dated January 5, 2005. Until U.S. EPA adopts specific New Source Review rules for PM2.5 emissions, it has directed states to regulate PM-10 emissions as a surrogate for PM2.5 emissions pursuant to the Nonattainment New Source Review requirements. See the State Rule Applicability – Entire Source section.

(c) Marion County has been classified as attainment or unclassifiable for all other criteria pollutants. Therefore, PM-10, SO_2, Lead and CO emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration, 326 IAC 2-2.

Fugitive Emissions

(d) This type of operation is not one of the 28 listed source categories under 326 IAC 2-2 or 326 IAC 2-3. However, 40 CFR 60.330 Subpart GG (September 10, 1979) is an applicable New Source Performance Standard that was in effect prior to August 7, 1980. Therefore, fugitive emissions, to the extent quantifiable, are included toward determination of PSD and Emission Offset applicability.

(e) On October 25, 2006, the Indiana Air Pollution Control Board finalized a rule revision to 326 IAC 1-4-1 redesignating Delaware, Greene, Jackson, Vanderburgh, Vigo and Warrick Counties to attainment for the eight-hour ozone standard, redesignating Lake County to attainment for the sulfur dioxide standard, and revoking the one-hour ozone standard in Indiana.

Source Status

Existing Source FESOP Definition (emissions after controls, based on 8760 hours of operation per year at rated capacity and/or as otherwise limited):

Pollutant	Emissions (tons/yr)
PM	3.06
PM-10	8.65
SO_2	1.20
VOC	98.47
CO	95.79
NO_x	95.91
Highest Single HAP	1.75
Combination HAPs	2.12

This existing source is not a major stationary source because no attainment regulated pollutant is emitted at a rate of 250 tons per year or greater and no nonattainment regulated pollutant is emitted at a rate of 100 tons per year or greater, and it is not in one of the 28 listed source categories.

Federal Rule Applicability

The following federal rules are applicable to the source:

(a) The One (1) Allison simple cycle Gas Turbine for refrigerant compressor, identified as Emission Unit ID 01, is subject to the requirements of the New Source Performance Standard, 40 CFR 60.330, Subpart GG (Standards of Performance for Stationary Gas Turbines) which is incorporated by reference as 326 IAC 12. The Allison simple cycle Gas Turbine identified as Emission Unit ID 01 is an affected facility stationary gas turbine because it was constructed after the rule applicability date of October 3, 1977, and has a heat input at peak load greater than or equal to 10.7 gigajoules (38 MMBtu per hour x 10^6 Btu/MMBtu x 1.055^3 joules/Btu x gigajoule/10^9 joules = 40.1 gigajoules).

Nonapplicable portions of the NSPS will not be included in the permit. The Allison simple cycle Gas Turbine, identified as Emission Unit ID 01, is subject to the following portions of Subpart GG:

(1) 40 CFR 60.330
(2) 40 CFR 60.331
(3) 40 CFR 60.332(a)(2)

(4) 40 CFR 60.332(c)
(5) 40 CFR 60.332(k)
(6) 40 CFR 60.333
(7) 40 CFR 60.334(c)
(8) 40 CFR 60.334(h)
(9) 40 CFR 60.334(i)
(10) 40 CFR 60.334(j)(1)(ii)
(11) 40 CFR 60.334(j)(2)
(12) 40 CFR 60.334(4)
(13) 40 CFR 60.334(5)
(14) 40 CFR 60.335

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12, apply to the one (1) Allison simple cycle Gas Turbine for refrigerant compressor, identified as Emission Unit ID 01, except when otherwise specified in 40 CFR 63 Subpart, Subpart GG.

(b) Emission Unit ID 02, 03 and 04, the T-Thermal Vaporizers, are each subject to 40 CFR 60.40c Subpart Dc (New Source Performance Standards - Standards of Performance for Small Industrial - Commercial - Institutional Steam Generating Units) which is incorporated by reference as 326 IAC 12. 40 CFR 60.41c defines *steam generating unit* as a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. *Heat transfer medium* is defined as any material that is used to transfer heat from one point to another point. Each of the three T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04, heat water to utilize as a *heat transfer medium* in order to vaporize liquefied natural gas for the distribution system. Subpart Dc is applicable to each affected facility steam generating unit for which construction, modification or reconstruction is commenced after June 9, 1989 and has a maximum design heat input capacity of 100 million Btu per hour or less but greater than or equal to 10 million Btu per hour. Emission Unit ID 02, 03 and 04 commenced construction after June 9, 1989 and each have a heat input greater than 10 million Btu per hour. On February 27, 2006, U. S. EPA amended 40 CFR 60.40c to eliminate the daily record keeping requirement for natural gas fuel consumption in affected emission units. However, the Indiana Air Pollution Control Board has not completed rule making to adopt these changes. Therefore, the T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04 are still subject to 40 CFR Part 60, Subpart Dc (July 1, 2002 version) and 326 IAC 12.

Nonapplicable portions of the NSPS will not be included in the permit. The T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04, are each subject to the following portions of Subpart Dc:

(1) 40 CFR 60.40c
(2) 40 CFR 60.41c
(3) 40 CFR 60.48c(a)
(4) 40 CFR 60.48c(g)

The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12, apply to the T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04, except when otherwise specified in 40 CFR 60, Subpart Dc.

(c) The one (1) 12,000 gallon ethylene storage tank, identified as Emission Unit ID Ethylene Storage Tank, had been subject to the record keeping requirements of the New Source Performance Standard, 40 CFR 60.110b, Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for

Which Construction, Reconstruction, or Modification Commenced After July 23, 1984), because the storage tank is a volatile organic liquid storage tank for which construction, modification or reconstruction commenced after July 23, 1984 and the storage tank has a capacity greater than 40 cubic meters (10,568 gallons). On October 15, 2003, U. S. EPA amended 40 CFR 60.110b to eliminate the record keeping requirement for storage vessels with a capacity less than 75 cubic meters (19,815 gallons). In the March 1, 2005 Indiana Register, the Indiana Air Pollution Control Board published a Proposed Rule Notice to adopt in 326 IAC 1-1-3 (CFR References) the July 1, 2004 Code of Federal Regulations (CFR) version in order to incorporate all Federal Rule revisions in CFR through July 1, 2004. The proposed rule became effective November 13, 2005. Therefore, the Ethylene Storage Tank is no longer subject to 40 CFR Part 60, Subpart Kb and 326 IAC 12.

The one (1) 10,000 gallon pentane storage tank and the one (1) 3,500 gallon butane storage tank, each installed in 1990, are each not subject to the New Source Performance Standard, 326 IAC 12, (40 CFR Part 60.110b, Subpart Kb), (Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction or Modification Commenced after July 23, 1984), because each tank has a storage capacity of less than 75 cubic meters (19,815 gallons).

(d) Citizens Gas is not subject to 40 CFR Part 60, Subpart KKK (Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants) because this processing site is not engaged in the extraction of natural gas liquids from field gas or the fractionation of mixed natural gas liquids to natural gas products. Therefore, pursuant to 40 CFR 60.630(e), Subpart KKK does not apply to this source.

(e) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs)(326 IAC 14, 40 CFR Part 61, 326 IAC 20, or 40 CFR Part 63) included in this permit.

This source is not subject to the requirements of the National Emission Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart HHH (Natural Gas Transmission and Storage Facilities), 40 CFR Part 63, Subpart YYYY (Stationary Combustion Turbines), 40 CFR Part 63, Subpart DDDDD (Industrial, Commercial and Institutional Boilers and Process Heaters) and 40 CFR Part 63, Subpart ZZZZ (Stationary Reciprocating Internal Combustion Engines) because this source is not a major source of hazardous air pollutants (HAP).

(e) The requirements of 40 CFR Part 64, Compliance Assurance Monitoring, are not applicable to this source. Such requirements apply to a pollutant specific emissions unit (PSEU), as defined in 40 CFR 64.1, at a major source that is required to obtain a Part 70 or 71 permit if the PSEU meets the following criteria:

(1) the unit is subject to an emission limitation or standard for an applicable regulated air pollutant;

(2) the unit uses a control device as defined in 40 CFR 64.1 to comply with that emission limitation or standard; and

(3) the unit has a potential to emit (PTE) before controls equal or greater than 100 percent of the amount (tons per year) of the pollutant required for a source to be classified as a Part 70 major source.

This source is operating as a FESOP and is not operating under a Part 70 Operating Permit source. Therefore, the requirements of 40 CFR 64, Compliance Assurance Monitoring, are not applicable to this source.

State Rule Applicability – Entire Source

326 IAC 1-7 (Stack Height Provisions)

This source does not have potential or actual PM or SO_2 emissions greater than twenty (25) tons per year. Therefore, the source is not subject to 326 IAC 1-7 (Stack Height Provisions).

326 IAC 2-1.1-5 (Air Quality Requirements)

Marion County has been designated as nonattainment for PM2.5. According to an EPA guidance memo dated April 5, 2005, PM-10 is to be utilized as a surrogate for PM2.5 until the EPA can promulgate the PM2.5 implementation rule. PM-10 emissions, and therefore PM2.5 emissions, from this source are less than one hundred (100) tons per twelve consecutive month period. There have been no modifications to this source such that it is a major source of PM-10 emissions. Therefore, this source is not subject to nonattainment new source review requirements for PM2.5 emissions.

326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements) and 326 IAC 2-3 (Emission Offset)

This existing source is not a major stationary source because no attainment regulated pollutant emissions are equal to or greater than two hundred fifty (250) tons per year, this source is not one of the 28 listed source categories under 326 IAC 2-2 or 326 IAC 2-3 and no attainment or nonattainment regulated pollutant emissions are equal to or greater than one hundred (100) tons per year. This source commenced construction and operation in 1990. See State Rule Applicability – Individual Facilities for an additional discussion of individual facilities limited by Installation Permit number 900141-01 on November 6, 1990 such that 326 IAC 2-3 does not apply to NO_X emissions from this source. There have been no modifications or revisions to this source that were major modifications pursuant to 326 IAC 2-2 or 326 IAC 2-3. Therefore, 326 IAC 2-2 (Prevention of Significant Deterioration (PSD) Requirements) and 326 IAC 2-3 (Emission Offset) are each not applicable to the source.

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

This existing source commenced operation prior to July 27, 1997 and does not have the potential to emit any individual single hazardous air pollutant (HAP) equal to or greater than ten (10) tons per year nor does this source have the potential to emit HAP of equal to or greater than twenty-five (25) tons per year for any combination of HAP. This source did not undergo construction or reconstruction of a major HAP source after July 27, 1997. Therefore, this source is not subject to 326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants).

326 IAC 2-6 (Emission Reporting)

Pursuant to 326 IAC 2-6-1(a)(1), (2), and (3), this source is not subject to 326 IAC 2-6 (Emission Reporting) because, as a FESOP source, it is not required to have an operating permit under 326 IAC 2-7, it does not emit lead into the ambient air at levels equal to or greater than five (5) tons per year, and it is not located in Lake or Porter Counties. However, pursuant to 326 IAC 2-6-1(b), as a permitted source in Indiana, it is subject to 326 IAC 2-6-5 (Additional Information Requests).

326 IAC 4-2 (Incinerators)

This source does not have an incinerator. Therefore, this source is not subject to 326 IAC 4-2 (Incinerators).

326 IAC 5-1 (Opacity Limitations)

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

(a) Opacity shall not exceed an average of thirty percent (30%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

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

326 IAC 6.5-1-2 (Particulate Matter Limitations Except Lake County) and 326 IAC 6.5-6 (Marion County)

This source has the potential to emit particulate of less than one hundred (100) tons per year and has actual emissions less than ten (10) tons per year. Citizens Gas & Coke Utility – LNG North is not specifically identified in 326 IAC 6.5-6 (Marion County). Therefore, 326 IAC 6.5-1-2 (Particulate Matter Limitations Except Lake County) and 326 IAC 6.5-6 (Marion County) each do not apply to this source.

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)

See discussion under State Rule Applicability – Individual Facilities of this Technical Support Document.

326 IAC 6-4 (Fugitive Dust Emissions)

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

326 IAC 6-5 (Fugitive Particulate Matter Emissions)

This source does not have the potential to emit fugitive particulate matter equal to or greater than twenty five (25) tons per year. Therefore, this source is not subject to 326 IAC 6-5 (Fugitive Particulate Matter Emissions).

326 IAC 7 (Sulfur Dioxide Rules)

Neither the source or any specific emission unit at this source has the potential to emit twenty five (25) tons per year or ten (10) pounds per hour of sulfur dioxide (SO_2). Therefore, this source is not subject to 326 IAC 326 IAC 7 (Sulfur Dioxide Rules).

326 IAC 7-4-2 (Marion County Sulfur Dioxide Emission Limitations)

Neither the source or any specific emission unit at this source is specifically identified in 326 IAC 7-4-2. Therefore, 326 IAC 7-4-2 (Marion County Sulfur Dioxide Emission Limitations) does not apply to this source.

326 IAC 8 (Volatile Organic Compound Rules)

See discussion under State Rule Applicability – Individual Facilities of this Technical Support Document.

326 IAC 9 (Carbon Monoxide Emission Rules)

There are no provisions under 326 IAC 9 (Carbon Monixide Emission Rules) applicable to any specific emission unit or operation at this source. Therefore, this source is not subject to 326 IAC 9 (Carbon Monoxide Emission Rules).

326 IAC 10 (Nitrogen Oxide Rules)

There are no provisions under 326 IAC 10 (Nitrogen Oxide Rules) applicable to any specific emission unit or operation at this source. This source has not opted in to 326 IAC 10 (Nitrogen Oxide Rules). Therefore, this source is not subject to 326 IAC 10 (Nitrogen Oxide Rules).

326 IAC 11 (Emission Limitations for Specific Types of Operations)

This liquefied natural gas storage plant does not perform any specific type of operation identified in 326 IAC 11 (Emission Limitations for Specific Types of Operations). Therefore, this source is not subject to 326 IAC 11 (Emission Limitations for Specific Types of Operations).

326 IAC 12 (New Source Performance Standards)

See discussion under Federal Rule Applicability and State Rule Applicability – Individual Facilities of this Technical Support Document.

326 IAC 14 (Emission Standards for Hazardous Air Pollutants)

There are no provisions under 326 IAC 14 (Emission Standards for Hazardous Air Pollutants) and 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants) applicable to any specific emission unit or operation at this source. Therefore, this source is not subject to the provisions of 326 IAC 14 (Emission Standards for Hazardous Air Pollutants) and 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

326 IAC 15 (Lead Rules)

Citizens Gas & Coke Utility – LNG North is not specifically identified in 326 IAC 15 (Lead Rules) and there are no provisions under 326 IAC 15 (Lead Rules) applicable to any specific emission unit or operation at this source. Therefore, this source is not subject to 326 IAC 15 (Lead Rules).

326 IAC 17 (Public Records; Confidential Information; Confidentiality Agreements)

This source has not filed or claimed any application, source or permit information as confidential, pursuant to 326 IAC 17-1-6 (Public Records: Confidentiality Claims), for this review and FESOP Renewal issuance, 097-18805-00141.

326 IAC 20 (Hazardous Air Pollutants)

This source is not a major source of hazardous air pollutants (HAP) and does not perform operations specifically identified in 326 IAC 20. Therefore, this source is not subject to 326 IAC 20 (Hazardous Air Pollutants) and 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants).

326 IAC 21 (Acid Deposition Control)

Citizens Gas & Coke Utility – LNG North operations are not subject to the Acid Rain Program Provisions of Title IV of the 1990 Clean Air Act Amendments as listed in 40 CFR Part 72 through 78 and are, therefore, not subject to 326 IAC 21 (Acid Deposition Control).

State Rule Applicability – Individual Facilities

326 IAC 2-3 (Emission Offset) and 326 IAC 2-8 (FESOP); Installation Permit number 900141-01

(a) Installation Permit number 900141-01 issued by the City of Indianapolis on November 6, 1990 limited NO_X emissions from the Allison simple cycle Gas Turbine, Emission Unit ID 01, to 32.1 pounds per hour and 83.6 tons per year such that 326 IAC 2-3 (Emission Offset) did not apply to this source. The Allison simple cycle Gas Turbine, Emission Unit ID 01, was additionally limited by the Installation Permit to 5200 annual operating hours and the nitrogen content for gas turbine fuel consumed in the Allison simple cycle Gas Turbine was limited to 23.2 percent by weight. The initial FESOP issued to this source, F097-10018-00141, on June 1, 1999 did not retain the annual operating hour limitation because it was not practically enforceable. At the nitrogen content limitation of 23.2 percent by weight for gas turbine fuel consumed, NO_X emissions from the Allison simple cycle Gas Turbine equate to 32.1 pounds per hour and 846 pounds per million cubic feet (lbs/MMCF) of natural gas burned (see Appendix A page 2 of 7).

Therefore, pursuant to 326 IAC 2-3 (Emission Offset) and 326 IAC 2-8 (FESOP), the nitrogen content for gas turbine fuel consumed shall not exceed 23.2 percent by weight, NO_X emissions from the Allison simple cycle Gas Turbine, Emission Unit ID 01, shall not exceed 32.1 pounds per hour and shall not exceed 846 pounds per million cubic feet (lbs/MMCF) of natural gas burned (see Appendix A page 2 of 7). Compliance with this condition demonstrates compliance with Installation Permit number 900141-01, issued November 6, 1990.

(b) Installation Permit number 900141-01 issued by the City of Indianapolis on November 6, 1990 limited NO_X emissions from the three T-Thermal water submerged Vaporizers (Unit IDs 02 – 04) to 11.1 pounds per hour and 3.3 tons per year. The three T-Thermal water submerged Vaporizers (Unit IDs 02 – 04) were additionally limited by the Installation Permit to a combined total 600 annual operating hours. The initial FESOP issued to this source, F097-10018-00141 on June 1, 1999 did not retain the annual operating hour limitation because it was not practically enforceable. At the NO_X emission factor of 100 pounds per million cubic feet (lbs/MMCF) of natural gas burned (see Appendix A page 3 of 7), NO_X emissions from each Vaporizer equate to 7.19 pounds per hour. Therefore, the NO_X emission rates from Installation Permit number 900141-01 for the three T-Thermal water submerged Vaporizers (Unit IDs 02 – 04) of 11.1 pounds per hour and 3.3 tons per year are not retained for this FESOP Renewal, F097-18805-00141.

Pursuant to 326 IAC 2-3 (Emission Offset) and 326 IAC 2-8 (FESOP), NO_X emissions from each T-Thermal water submerged Vaporizer, identified as Emission Unit ID 02, 03 and 04, shall not exceed 100 pounds per million cubic feet (lbs/MMCF) of natural gas burned. Compliance with this condition demonstrates compliance with Installation Permit number 900141-01, issued November 6, 1990.

(c) Pursuant to 326 IAC 2-8-4 (FESOP; Permit Content), NO_X emissions from the Waukesha Emergency Generator, identified as Emission Unit ID WEG 1, shall not exceed 3,170 pounds per million cubic feet (lbs/MMCF) of natural gas burned (see Appendix A page 5 of 7).

(d) Pursuant to 326 IAC 2-8-4 (FESOP; Permit Content), NO_X emissions from the diesel fuel fired emergency fire pump, Emission Unit ID EFP-01, shall not exceed 0.6 pounds per gallon (lbs/gal) of diesel fuel burned (see Appendix A page 6 of 7).

(e) Citizens Gas specifically requested in the FESOP Renewal application that NO_X emissions from significant and insignificant activity emission units and the source sum to, approximately, 95.0 tons per twelve consecutive month period. Pursuant to 326 IAC 2-3 (Emission Offset) and 326 IAC 2-8 (FESOP), the combined total NO_X emissions from the Allison simple cycle Gas Turbine, Emission Unit ID 01, the three T-Thermal water submerged Vaporizers, Emission Unit IDs 02 – 04, the Waukesha Emergency Generator, Emission Unit ID WEG 1, and the diesel fuel fired emergency fire pump, Emission Unit ID EFP-01, shall not exceed 93.06 tons per twelve (12) consecutive month period with compliance determined at the end of each month (see Appendix A page 1 of 7).

Compliance with this condition shall be determined by the following equation:

E = [(846 lbs/MMCF) x (actual monthly fuel use in MMCF this month in the Allison simple cycle Gas Turbine) + (100 lbs/MMCF) x (combined actual monthly fuel use in MMCF this month in the three T-Thermal water submerged Vaporizers) + (3,170 lbs/MMCF) x (actual monthly fuel use in MMCF this month in the Waukesha Emergency Generator) + (0.6 lbs/gal) x (actual monthly fuel use in gallons this month in the diesel fuel fired emergency fire pump)] + P

Where: E = actual NO_X emissions per twelve (12) consecutive month period
P = actual NO_X emissions in the previous eleven (11) consecutive month period

Compliance with this condition shall limit total NO_X emissions from the source to less than 100 tons per twelve (12) consecutive month period with compliance determined at the end of each month and demonstrates compliance with and 326 IAC 2-3 (Emission Offset) and Installation Permit number 900141-01, issued November 6, 1990. Therefore, the requirements of 326 IAC 2-7 (Part 70) and 326 IAC 2-3 (Emission Offset) do not apply to the source (see Appendix A page 1 of 7).

326 IAC 6-2-4 (Particulate Emission Limitations for Facilities Specified in 326 IAC 6-2-1(d))

This rule establishes limitations for sources of indirect heating, receiving permits to construct on or after September 21, 1983. The three (3) T-Thermal Vaporizers (Unit ID 02, 03 and 04) for this source, each with maximum heat input capacity of 72.0 million Btu per hour (MMBtu/hr), are subject 326 IAC 6-2-4 (Particulate Emissions Limitations for Sources of Indirect Heating specified in 326 IAC 6-2-1(d)), because each were installed in 1990, after the September 21, 1983 rule applicability date. The Salt Bath heater for mole sieve regeneration, identified as Emission Unit ID SBH-01, operated while natural gas is being liquefied, is also subject to 326 IAC 6-2-4 because it is a natural gas fired indirect heating unit with a maximum heat input capacity of 6.5 MMBtu/hr and was installed in 1990, after the September 21, 1983 rule applicability date.

Pursuant to 326 IAC 6-2-4(a), PM emissions rate from the three (3) Vaporizers and the Salt Bath heater for mole sieve regeneration, based on a total heat input rate of 222.50 MMBtu per hour, shall each be limited to 0.27 pounds per MMBtu heat input.

This limitation is based on the following equation:

$Pt = \frac{1.09}{Q^{0.26}}$ where: Pt = Pounds of particulate matter emitted per MMBtu heat input.
Q = Total source maximum operating capacity rating in MMBtu per hour.
Q = 222.50 MMBtu/hr

$Pt = \frac{1.09}{(222.50)^{0.26}}$ = 0.27 pound per MMBtu heat input each.

The potential particulate matter emissions from the vaporizers and the Salt Bath heater for mole sieve regeneration are each 0.002 pound per MMBtu heat input (see Appendix A page 3 of 7). Therefore, the three (3) vaporizers and the Salt Bath heater for mole sieve regeneration are each capable of complying with 326 IAC 6-2-4.

326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes)

Reciprocating internal combustion engines are not specifically identified in 326 IAC 6-3-2(b) through (d). Pursuant to 326 IAC 1-2-59, “Process weight; weight rate,” states that liquid and gaseous fuels will not be considered as part of the process rate. Therefore, the Waukesha Emergency Generator, identified as Emission Unit ID WEG 1, and the diesel fuel fired emergency fire pump, identified as Emission Unit ID EFP-01, are each not subject to 326 IAC 6-3-2(e). Therefore, 326 IAC 6-3 (Particulate Emission Limitations for Manufacturing Processes) does not apply to Emission Unit ID WEG 1 and Emission Unit ID EFP-01.

326 IAC 8-1-6 (General Volatile Organic Compound Reduction Requirements)

This rule applies to facilities located anywhere in the state that were constructed on or after January 1, 1980, which have potential volatile organic compound (VOC) emissions of twenty five (25) tons per year or more, and which are not otherwise regulated by other provisions of 326 IAC 8 (Volatile Organic Compound Rules).

Condition D.1.4 of the initial FESOP issued to this source, 097-10018-00141, on June 1, 1999 had limited volatile organic compound (VOC) emissions from Emission Unit ID 01, which includes the natural gas liquefaction compressor/heat exchange system, to less than twenty four (24.0) tons per rolling twelve (12) consecutive month period such that 326 IAC 8-1-6 does not apply. For compliance determination purposes, every ton of VOC delivered to the natural gas liquefaction compressor/heat exchange system is determined to be emitted. Citizens Gas had previously underestimated the actual amount of VOC needed, input and used in the natural gas liquefaction process. As a result, past actual VOC emissions have exceeded twenty-five (25) tons per year. Therefore, it is subject to the requirements of 326 IAC 8-1-6. Citizens Gas submitted a BACT analysis with the FESOP Renewal application. After conducting the top-down BACT analysis (refer to Appendix B of TSD), BACT for VOC emissions from the natural gas liquefaction process at Citizens Gas & Coke Utility - LNG North has been determined as follows (see Appendix B of TSD):

Pursuant to 326 IAC 8-1-6, VOC input shall be limited such that the potential to emit of VOC is less than ninety (90.0) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Ethylene (VOC) input not sent to the natural gas liquefaction compressor/heat exchange system from Emission Unit ID Ethylene Storage Tank shall only be vented into the vapor feed line directly into the natural gas distribution system.

Compliance shall be determined at the end of each month using the following equation:

E = (VOC input, in tons, this month – ethylene (VOC), in tons, this month sent to the natural gas distribution system) + P

Where: E = actual VOC emissions per twelve (12) consecutive month period
P = actual VOC emissions in the previous eleven (11) consecutive month period

326 IAC 12 (New Source Performance Standards)

(a) The one (1) Allison simple cycle Gas Turbine for refrigerant compressor, identified as Emission Unit ID 01, is subject to 326 IAC 12. 326 IAC 12 incorporates by reference 40 CFR 60.330, Subpart GG. The permittee will comply with the provisions of 40 CFR 60.330, Subpart GG as detailed in the Federal Rule Applicabilty Determination section above.

(b) The T-Thermal Vaporizers, identified as Emission Unit ID 02, 03 and 04, are each subject to 326 IAC 12. The permittee will comply with the provisions of 40 CFR 60.40c, Subpart Dc as detailed in the Federal Rule Applicabilty section.

Testing Requirements

NO_X emissions testing for the one (1) Allison simple cycle Gas Turbine for refrigerant compressor, identified as Emission Unit ID 01, was conducted on April 15, 2003. The NO_X stack test concentration of 118.6 ppmv verified compliance with the requirements of 40 CFR 60.330 Subpart GG (Standards of Performance for Stationary Gas Turbines). The NO_X stack testing emission rate of 17.55 pounds per hour verified compliance with the Condition D.1.2 limit in FESOP 097-10018-00141 of 32.1 pounds per hour. The Permittee will be allowed to skip one five (5) year test cycle of NO_X emissions testing for Emission Unit ID 01 because the Permittee monitors the nitrogen content of natural gas fired in the Gas Turbine daily to verify compliance with the provisions of 40 CFR 60.330 Subpart GG (Standards of Performance for Stationary Gas Turbines) and the previous emission test (April 15, 2003) at maximum unit capacity resulted in emissions of equal to or less than fifty five percent (55%) (17.55 lbs per hour / 32.1 pounds per hour x 100 = 55%) of the allowable short term NO_X emission rate.

Compliance Requirements

Permits issued under 326 IAC 2-8 are required to ensure that sources can demonstrate compliance with applicable state and federal rules on a more or less continuous basis. All state and federal rules contain compliance provisions, however, these provisions do not always fulfill the requirement for a more or less continuous demonstration. When this occurs IDEM, OAQ in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-8-4. As a result, compliance requirements are divided into two sections: Compliance Determination Requirements and Compliance Monitoring Requirements.

Compliance Determination Requirements in Section D of the permit are those conditions that are found more or less directly within state and federal rules and the violation of which serves as grounds for enforcement action. If these conditions are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the approporiate corrective actions within a specific time period.

Other than monitoring required pursuant to 40 CFR 60.40c, Subpart Dc and 40 CFR 60.330, Subpart GG (see Federal Rule Applicability section of this TSD), there are no compliance monitoring conditions.

Conclusion

The operation of this liquefied natural gas storage plant shall be subject to the conditions of FESOP Renewal 097-18805-00141.

Appendix A: Emission Calculations
Summary

Company Name: Citizens Gas & Coke Utility - LNG North
Address City IN Zip: 4536 West 86th Street, Indianapolis, IN 46268
Permit No.: 097-18805-00141
Reviewer: M. Caraher
Date: October 13, 2006

(Uncontrolled) Potential to Emit (tons/year)

	Emissions Generating Activity						
Pollutant	Allison Turbine *	Vaporizers	Salt Bath	Emergency Generator	Fire Pump	Pentane Tank	**TOTAL**
PM	1.10	1.80	0.05	0.01	0.09	0.00	3.06
PM10	1.10	7.19	0.22	0.06	0.09	0.00	8.65
SO2	0.53	0.57	0.02	0.00	0.08	0.00	1.20
NOx	140.81	94.61	2.85	4.76	1.29	0.00	244.31
VOC	1.83	5.20	0.16	0.18	0.11	0.99	8.47
CO	13.65	79.47	2.39	0.00	0.28	0.00	95.79
total HAPs	0.17	1.79	0.05	0.12	3.45E-04	0.00	2.12
Hexane - HAP	0.00	1.70	0.05	0.00	0.00	0.00	1.75
Formaldehyde - HAP	0.12	0.07	2.14E-03	0.08	3.45E-04	0.00	0.27

Total emissions based on rated capacity at 8,760 hours/year. * Add 90 tons VOC refrigerant loss to Allison Turbine VOC total.

Limited Potential to Emit (tons/year)

	Emissions Generating Activity						
Pollutant	Allison Turbine *	Vaporizers	Salt Bath	Emergency Generator	Fire Pump	Pentane Tank	**TOTAL**
PM	1.10	1.80	0.05	0.01	0.09	0.00	3.06
PM10	1.10	7.19	0.22	0.06	0.09	0.00	8.65
SO2	0.53	0.57	0.02	0.00	0.08	0.00	1.20
NOx	93.06		2.85	**		0.00	95.91
VOC	1.83	5.20	0.16	0.18	0.11	0.99	98.47
CO	13.65	79.47	2.39	0.00	0.28	0.00	95.79
total HAPs	0.17	1.79	0.05	0.12	3.45E-04	0.00	2.12
Hexane - HAP	0.00	1.70	0.05	0.00	0.00	0.00	1.75
Formaldehyde - HAP	0.12	0.07	2.14E-03	0.08	3.45E-04	0.00	0.27

*** Added 90 tons VOC refrigerant loss to Allison Turbine VOC total.**

Total emissions based on rated capacity at 8,760 hours/year, after enforceable control and limits. 18885calc.xls

**Note: NOX emissions from the Allison Turbine, Vaporizers, Emergency Generator and Fire Pump shall be limited to less than 93.06 tpy such that 326 IAC 2-3 and 326 IAC 2-7 do not apply.

Appendix A: Emission Calculations
Natural Gas - Gas Turbine - Simple Cycle
(for refrigerant compressor)
Company Name: Citizens Gas & Coke Utility - LNG North
Address City IN Zip: 4536 West 86th Street, Indianapolis, IN 46268
Permit No.: 097-18805-00141
Reviewer: M. Caraher
Date: October 13, 2006

A. One (1) Allison Gas Turbine (Unit ID 01).

Heat Input Capacity: 38.00 MMBtu/hr
Hours of Operation: 8760 hour/year
Limited PTE for NOX at: 220.00 MMCF/yr

	Emission Factors		Potential to Emit		Limited Potential to Emit
Pollutant	AP-42 Factor		lb/hr	ton/yr	ton/yr
	lb/MMBtu	lb/MMCF			
PM	6.60E-03	6.60E+00	0.2508	1.10	1.10
PM10	6.60E-03	6.60E+00	0.2508	1.10	1.10
SO2*	3.20E-03	3.20E+00	0.1214	0.53	0.53
NOx ** (Subpart GG)	n/a	8.46E+02	32.1480	140.81	93.06
VOC	1.1E-02	1.1E+01	0.4180	1.83	1.83
CO	8.20E-02	8.20E+01	3.1160	13.65	13.65
Refrigerant VOC	*n/a*	*n/a*		*90.00*	*90.00*
HAPs	AP-42 Factor		lb/hr	ton/yr	ton/yr
	lb/MMBtu				
Acetaldehyde	4.00E-05		1.52E-03	6.66E-03	
Acrolein	6.40E-06		2.43E-04	1.07E-03	
Benzene	1.20E-05		4.56E-04	2.00E-03	
Ethylbenzene	3.20E-05		1.22E-03	5.33E-03	
Formaldehyde ***	7.10E-04	7.10E-01	2.70E-02	1.18E-01	1.18E-01
Napthalene	1.30E-06		4.94E-05	2.16E-04	
PAH	2.20E-06		8.36E-05	3.66E-04	
Toluene	1.30E-04		4.94E-03	2.16E-02	
Xylene	6.40E-05		2.43E-03	1.07E-02	
Total	9.98E-04	9.98E-01	3.79E-02	1.66E-01	1.66E-01

Note: Citizens Gas LNG North estimates max emissions of VOC for refrigerant compressor at 90 tpy

Actual emissions will be determined and recorded daily using a mass balance approach.

Methodology

* SO2 emission factor is based on default value as per AP-42 Table 3.1-2a (footnote h) (April 2000).
** NOx emission factor based on Subpart GG allowable NO_X emissions of 32.148 lbs/hr.

NO_X emfac = 38 MMBtu/hr / 1000 Btu x X lb/MMCF = 32.148 lbs/hr (X = 846 lb/MMCF)

*** Highest Single HAP

VOC, HAP, PM, PM10, and SO2 emission factors are from AP 42, Chapter 3.1, Table 3.1-1, 3.1-2a, and 3.1-3.
(Natural Gas-fired Stationary Gas Engines) (Supplemental F, 4/2000).

PM equals PM10. Total PM consists of PM condensible and PM filterable.

Emission (tons/yr) = [Heat input rate (MMBtu/hr) x Emission Factor (lb/MMBtu)] * 8760 hr/yr / (2,000 lb/ton)
Emission factor in lb/MMCF=lb/MMBtu * 1000; Limited PTE for NO_X=enforceable emission factor * estimated fuel use under emissions cap

NOX emission limitation for Allison Turbine: 18805calcs.xls

The following calculations determine the amount of NO_X emissions created by natural gas combustion

based on a maximum fuel usage of 220.00 MMCF

Natural Gas: 220.00 MMCF/yr / 2,000 lb/ton * Ef (lb/MMCF) = (ton/yr)

N O x: 846.0 lb/MMCF = **93.06 ton/yr**

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Vaporizers & Salt Bath

Company Name: Citizens Gas & Coke Utility - LNG North
Address City IN Zip: 4536 West 86th Street, Indianapolis, IN 46268
Permit Number: 097-18805-00141
Reviewer: M. Caraher
Date: October 13, 2006

Heat Input Capacity MMBtu/hr		Potential Throughput MMCF/yr
216.0	= 3 vaporizers @ 72 MMBtu each	1892.2
6.5	= 1 salt bath heater	56.9

	Pollutant					
	PM*	PM10*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	0.6	100.0	5.5	84.0
Emission Factor in lb/MMBtu	0.002		0.0006	**see below		
Potential Emission in tons/yr (Vaporizers)	1.80	7.19	0.57	94.61	5.20	79.47
Potential Emission in tons/yr (Salt Bath)	0.05	0.22	0.02	2.85	0.16	2.39

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology

All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu
MMCF = 1,000,000 Cubic Feet of Gas
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,000 MMBtu
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03 (SUPPLEMENT D 3/98)
Emission (tons/yr) = Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

See page 4 for HAPs emissions calculations.

Appendix A: Emissions Calculations
Natural Gas Combustion Only
MM BTU/HR <100
Vaporizers & Salt Bath
HAPs Emissions

Company Name: Citizen's Gas & Coke Utility (LNG North)
Address City IN Zip: 4536 West 86th Street, Indianapolis, IN 46268
Permit Number: 097-18805-00141
Reviewer: M. Caraher
Date: October 13, 2006

	HAPs - Organics				
	Benzene	Dichlorobenze	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Potential Emission in tons/yr (Vaporizers)	1.987E-03	1.135E-03	7.096E-02	1.703E+00	########
Potential Emission in tons/yr (Salt Bath)	5.979E-05	3.416E-05	2.135E-03	5.125E-02	########

	HAPs - Metals					Total HAPS
	Lead	Cadmium	Chromium	Manganese	Nickel	
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03	
Potential Emission in tons/yr (Vaporizers)	4.730E-04	1.041E-03	1.325E-03	3.595E-04	########	1.79
Potential Emission in tons/yr (Salt Bath)	1.424E-05	3.132E-05	3.986E-05	1.082E-05	########	0.05

Methodology is the same as page 3.

The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emission Calculations
Internal Combustion Engines - Natural Gas
> 600 HP
Reciprocating

Company Name: **Citizens Gas & Coke Utility - LNG North**
Address City IN Zip: **4536 West 86th Street, Indianapolis, IN 46268**
Permit Number: **097-18805-00141**
Reviewer: **M. Caraher**
Date: **October 13, 2006**

Emission Unit ID WEG1 Emergency Generator:

Max Engine Capacity: 2346 horsepower
6 MMBtu/hr =0.006 MMCF/hr

Hours of Operation: 500 hour/year =3 MMCF/yr

	Emission Factors	Total Emissions	
Pollutant	AP-42 Factor	lb/hr	ton/yr
	lb/10^6 Btu		
PM	9.91E-03	0.0595	0.0149
PM10	3.84E-02	0.230400	0.0576
SO2	5.88E-04	0.0035	0.0009
NOx *	3.17E+00	19.0200	4.7550
VOC	1.2E-01	0.7200	0.1800
CO	3.86E-04	0.0023	0.0006
HAPs	AP-42 Factor	lb/hr	ton/yr
	lb/10^6 Btu		
Acetaldehyde	7.76E-03	0.04656	0.01164
Acrolein	7.78E-03	0.04668	0.01167
Benzene	1.94E-03	0.01164	0.00291
Biphenyl	3.95E-06	0.00002	0.00001
1,3-Butadiene	8.20E-04	0.00492	0.00123
Carbon Tetrachloride	6.07E-05	0.00036	0.00009
Chlorobenzene	4.44E-05	0.00027	0.00007
Chloroform	4.71E-05	0.00028	0.00007
1,3-Dichloropropene	4.38E-04	0.00263	0.00066
Ethylbenzene	1.08E-04	0.00065	0.00016
Ethylene Dibromide	7.34E-05	0.00044	0.00011
Formaldehyde	5.52E-02	0.33120	0.08280
Methanol	2.48E-03	0.01488	0.00372
Methylene Chloride	1.47E-04	0.00088	0.00022
Napthalene	9.63E-05	0.00058	0.00014
Phenol	4.21E-05	0.00025	0.00006
Styrene	5.48E-05	0.00033	0.00008
Toluene	9.63E-04	0.00578	0.00144
1,1,2,2-Tetrachloroethane	6.63E-05	0.00040	0.00010
1,1,2-Trichloroethane	5.27E-05	0.00032	0.00008
2,2,4-Trimethylpentane	8.46E-04	0.00508	0.00127
Vinyl Chloride	2.47E-05	0.00015	0.00004
Xylene	2.68E-04	0.00161	0.00040
Total HAPs		4.8E-01	0.12
Highest Single HAP:	Formaldehyde		0.08

Methodology

Emfacs in lb/MMBtu from AP-42 Table 3.2-1, SCC# 2-02-002-52 Criteria Emission Factors for Natural Gas (2-Cycle Lean Burn)

Potential Emissions (lbs / hr): MMBtu / hr x lbs / MMBtu

Potential Emissions (tons / yr): lbs / hr emissions x 500 operating hrs / yr x ton / 2000 lbs

*** NOX emissions in lb/MMCF = 3.17 lbs/MMBtu x 1000 Btu/cubic foot x 10^6 cubic feet/ 10^6 Btu = 3170 lbs/MMCF**

Appendix A: Emissions Calculations
Diesel Fuel Combustion Only
Internal Combustion Engines - Industrial Reciprocating
< 600 hp

Emergency Fire Pump
diesel fuel fired
460 HP
Emission Unit ID EFP-01

Company Name: **Citizens Gas & Coke Utility - LNG North**
Address City IN Zip: **4536 West 86th Street, Indianapolis, IN 46268**
Permit Number: **097-18805-00141**
Reviewer: **M. Caraher**
Date: **October 13, 2006**

maximum heat input MMBtu / hr	maximum heat input MCCF / hr	equivalent kilowatt hr
1.2	0.0012	342.5

fuel S = 0.4 percent by weight

equivalent horsepower
459

	PM	PM10	SOx	NOx	VOC	CO	Highest Single HAP Formadehyde
Emission Factor lbs / MMBtu	0.31	0.31	0.29	4.41	0.36	0.95	1.18E-03
Potential Emissions lbs / hr	0.36	0.36	0.34	5.15	0.42	1.11	1.38E-03
tons / yr @ 500 hrs / yr	0.09	0.09	0.08	1.29	0.11	0.28	3.45E-04

Methodology

AP-42 Appendix A Conversion Factor: 1 kilowatt hour = 3410 Btu
AP-42 Appendix A Conversion Factor: 1 horsepower = 2.5435E03 Btu

Equivalent kw hr rating: (max heat input MMBtu / hr) / (3410 Btu / kw hr)
Equivalent Horsepower: million Btu / 2.5435E03
Emission Factor (lbs / MMBtu): from AP-42 Table 3.3-1 & 3.3-2 Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines
Diesel fuel Btu: 137000 Btu/gal (per AP-42 Appendix A)
Potential Emissions (lbs / hr): emfac x heat input
Potential Emissions (tons / yr): lbs / hr emissions x 500 operating hrs / yr x ton / 2000 lbs
if limited to: 500 annual operating hours, then 4379.6 gal/yr max annual diesel fuel consumption
diesel consumption gal/yr limitation: MMBtu/hr / (Btu/gal / 10^6) * 500 hrs/yr

NOX emissions in lb/gallon = 4.41 lbs/MMBtu x 137,000 Btu/gallon x 1 MMBtu/ 10^6 Btu = 0.6 lbs/gallon

Above ground Insignificant Activity Pentane Storage Tank

Appendix A: Emission Calculations
Tank Storage

Company Name: Citizens Gas & Coke Utility - LNG North
Address City IN Zip: 4536 West 86th Street, Indianapolis, IN 46268
Permit Number: 097-18805-00141
Reviewer: M. Caraher
Date: October 13, 2006

TANKS 4.0
Emissions Report - Summary Format

Tank Identification

User Identification:	Pentane Storage Tank
Type of Tank:	Horizontal
Description:	10000 gal

Tank Dimensions

Shell Length (ft):	15.0
Diameter (ft):	11.0
Liquid Height (ft):	15.0
Average Liquid Height (ft):	7.5
Volume (gal):	10000.0
Turnovers:	1.0
Net Throughput (gal/yr):	10000.0
Heated tank (y/n?)	No

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig):	0.0

Liquid Contents of Storage Tank

Component	Pentane

Daily Liquid Surface Temp (F)

Avg.:	54.0
Min.:	48.9
Max.:	59.1
Liquid Bulk Temp (F):	52.3

Vapor Pressure (psia):

Avg.:	5.97
Min.:	5.3
Max.:	6.7000
Vapor Molecular Wt.:	72.2
Molecular Wt.:	72.2

	Losses (lbs)		
Components	**Working Loss**	**Breathing Loss**	**Total Emissions**
Pentane	102.65	1883.8	1986.46
			0.99 (tons)

Methodology

Emission calculations based on EPA program "TANKS" Version 4.09b

Indiana Department of Environmental Management
Office of Air Quality
and
City of Indianapolis
Office of Environmental Services

Appendix B
Best Available Control Technology (BACT) Determination

Source Background and Description

Source Name:	**Citizens Gas & Coke Utility – LNG North**
Source Location:	**4536 West 86th Street, Indianapolis, IN 46268**
County:	**Marion**
SIC Code:	**4922**
Operation Permit No.:	**F097-10018-00141**
Operation Permit Issuance Date:	**June 1, 1999**
Permit Renewal No.:	**F097-18805-00141**
Permit Reviewer:	**M. Caraher**

The Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) and the City of Indianapolis, Office of Environmental Services (OES) have performed the following BACT review for the natural gas liquefaction process owned and operated by Citizens Gas & Coke Utility – LNG North (herein identified as Citizens Gas), located in Indianapolis, Indiana.

The source is located in Marion County, which is designated as nonattainment for the 8-hour ozone standard, nonattainment for PM2.5 and attainment for all other criteria pollutants. Based upon emission calculations completed by OAQ, OES and Citizens Gas, the natural gas liquefaction compressor/heat exchange system for the liquefaction process emits greater than twenty-five (25) tons per year of volatile organic compounds (VOC). The natural gas liquefaction compressor/heat exchange system for the liquefaction process was constructed on or after January 1, 1980. Therefore, pursuant to 326 IAC 8-1-6 (General Volatile Organic Compound Reduction Requirements) the source shall reduce VOC emissions from the liquefaction process, which are not otherwise regulated by other provisions of 326 IAC 8 (Volatile Organic Compound Rules), using best available control technology (BACT). BACT determinations pursuant to 326 IAC 8-1-6 do not require an ambient air quality analysis or additional environmental impact analyses. The purpose of this BACT Analysis is to evaluate the level of control that constitutes BACT for the affected facility.

The specific facilities requiring evaluation in this analysis include the refrigerant compressor and the natural gas liquefaction compressor/heat exchange system, including the ethylene storage tank identified as Emission Unit ID Ethylene Storage Tank. The One (1) Allison simple cycle Gas Turbine, identified as Emission Unit ID 01, is utilized to drive the refrigerant compressor. A mixture of refrigerant gases (including ethylene, propane, n-butane, i-pentane, methane and ethane) is circulated in a closed loop multi-pass heat exchanger to cool the natural gas feed to the liquefaction temperature of -260^0F. Ethylene, a VOC, typically comprises the highest amount of any VOC used in the refrigerant mixture. A maximum of 7.5 million standard cubic feet (approximately, 9 inches of liquid tank height) of liquefied natural gas can be produced daily during liquefaction events. The frequency and duration of liquefaction events depend on the amount of liquefied natural gas required or desired to replenish the storage tank of liquefied natural gas sent to the distribution system during peaking demand periods. VOC emissions due to liquefaction events only occur during tank storage of ethylene leading up to and after a liquefaction event and from refrigerant gas loss from the refrigerant compressor and the natural gas liquefaction compressor/heat exchange system. The refrigerant mixture used for a liquefaction event cannot be utilized for a subsequent liquefaction event because the refrigerant mixture utilized is dependent on ambient temperature and pressure. Therefore, Citizens Gas is constantly adjusting the desired relative concentration of each material in the mixed refrigerant system during a liquefaction event as the temperatures and pressures fluctuate.

IDEM, OAQ and OES conduct BACT analyses in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft USEPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. The steps are discussed as follows:

(a) Identify all potentially available control options;
(b) Eliminate technically infeasible control options;
(c) Rank remaining control technologies by control effectiveness;
(d) Evaluate the most effective controls considering environmental, economic and energy impacts and document the results; and
(e) Select BACT.

The following BACT determination is based on the following information:

(a) The BACT analysis submitted by Citizens Gas & Coke Utility – LNG North as part of the FESOP Renewal application on August 26, 2003. Additional information was submitted by Citizens Gas on September 8, 2005, on September 22, 2005, on December 21, 2005, on September 9, 2006, on September 22, 2006 and on November 10, 2006.
(b) Information from vendors/suppliers;
(c) The EPA RACT/BACT/LAER Clearinghouse (RBLC); and
(d) State, and Local air quality permits.

BACT Analysis for VOC emissions from the natural gas liquefaction process

(a) Identify all potentially available control options

The first step in evaluating potential applicable control technologies involves a review of control technology determinations made for permitted natural gas transmission and storage of natural gas sources. The USEPA's RACT /BACT /LAER Clearinghouse (RBLC) database was searched for the purpose of identifying comparable sources that have implemented BACT for the affected facilities. This search was performed in the following steps:

(1) A search was first conducted in the Natural Gas/Gasoline Processing Plants (50.002) category. Thirty (30) facilities and sixty-two (62) processes were identified in the RBLC database for the past ten (10) years. However, none of these sources listed ethylene use or VOC emissions from liquefied natural gas refrigerant compressor/heat exchange systems. In addition, none of these identified facilities are similar to this source.

(2) A search was then conducted in the Volatile Organic Liquid Storage (42.009) category. Forty-one (41) facilities and one hundred and fourteen (114) processes were identified in the RBLC database for the past ten (10) years. However, none of these sources listed ethylene use or VOC emissions from liquefied natural gas refrigerant compressor/heat exchange systems. In addition, none of these identified facilities are similar to this source.

(3) A search was conducted in the Inorganic Liquid/Gas Storage and Handling (62.020) category. No matching RBLC facilities were found for the past ten (10) years.

(4) A search was conducted in the Synthetic Organic Chemical Manufacturing Industry (SOCMI) for Storage Tanks (64.004) category. Twelve (12) facilities and forty-eight (48) processes were identified in the RBLC database for the past eleven (11) years. One (1) facility, Daikin America, Inc., listed an ethylene storage tank. The BACT determination for Daikin America, Inc. is an add-on control device with an efficiency of 99.99% as listed in the table below from the RBLC.

ID	Date	BACT /LAER	Determination	Facility
AL-0153	2/1/94	BACT	99.99% DRE Thermal Incinerator	Daikin America, Inc.

(5) A search was conducted of the entire RBLC for storage tanks not identified in the Natural Gas/Gasoline Processing Plants, Volatile Organic Liquid Storage, Inorganic Liquid/Gas Storage and Handling or Synthetic Organic Chemical Manufacturing Industry (SOCMI) for Storage Tanks category. Four (4) facilities were identified in the RBLC database for the past ten (10) years. However, none of these sources listed ethylene use or VOC emissions from liquefied natural gas refrigerant compressor/heat exchange systems. In addition, none of these identified facilities are similar to this source.

(6) Citizens Gas included in the BACT Analysis portion of the FESOP Renewal application, and in the additional information submitted December 21, 2005, on September 8, 2005 and on September 22, 2005, the following potentially available control options:

(A) Flare;
(B) Leak Detection and Repair Program;
(C) Liquid Nitrogen Cooling System for ethylene storage tank losses;
(D) Microturbine to combust ethylene emissions;
(E) Recuperative Thermal Incineration;
(F) Regenerative Thermal Incineration;
(G) Recuperative Catalytic Incineration;
(H) Regenerative Catalytic Incineration;
(I) Rerouting ethylene storage tank losses into the natural gas distribution system. Thus, the ethylene becomes part of the natural gas stream and is combusted off-site by end-users of the natural gas stream. This allows the capture of the following variable VOC emissions which would otherwise have been emitted from the site:

(i) Ethylene which “boils off” from tank storage during a liquefaction event. Pressure fluctuations in the ethylene storage tank result in boil off of ethylene during a liquefaction event.
(ii) Ethylene which is contained in the ethylene storage tank at the completion of a liquefaction event. Any ethylene which still remains in the storage tank is vented to the atmosphere due to the difficulty in keeping ethylene in a liquid state.

During the summer of 2005, Citizens Gas completed the rerouting of ethylene storage tank losses into the natural gas distribution system by adding a vapor feed line directly to the natural gas distribution system. This was verified by an OES plant tour of the liquefaction process on August 2, 2005. Therefore, the rerouting of ethylene storage tank emissions to the natural gas distribution is now part of the normal operation of the source.

(b) Eliminate technically infeasible control options

(1) Flare – This method is not considered technically feasible for Citizens Gas because an open flame within the facility represents a safety concern at a liquefied natural gas storage plant. In addition, the entire ethylene system for natural gas liquefaction is functioning for a limited period of time during the course of the year and only during natural gas liquefaction events. Also, a flare would increase the potential and actual CO and NO_X emission rates for this source which already has enforceable limitations on the potential to emit NO_X such that 326 IAC 2-3 and 326 IAC 2-7 does not otherwise apply to this source. In addition, a flare may not reasonably be stack tested to verify CO or NO_X

emission rates for these pollutants.

(2) Leak detection and repair program – A leak detection and repair program was evaluated and is considered not technically feasible for the following reasons:

(A) Many of the components, the numerous valves, flanges and fittings in the liquefaction compressor/heat exchange system, are inaccessible and can not be checked.
(B) The ethylene system is functioning for a limited period of time during the course of the year, thus inspections have limited benefits.

Due to the difficulty in accessing many components and the limited benefit to be gained, it has been determined that a LDAR program is not a feasible approach to reduce VOC emissions.

(3) Liquid Nitrogen Cooling System for ethylene storage tank losses – Installing a liquid nitrogen cooling system would be utilized to control ethylene storage tank losses. During the summer of 2005, Citizens Gas completed the rerouting of ethylene storage tank losses into the natural gas distribution system by adding a vapor feed line directly to the natural gas distribution system. Therefore, controlling ethylene storage tank losses with a liquid nitrogen cooling system is no longer evaluated as BACT for VOC emissions from the ethylene storage tank.

(4) Microturbine – Citizens Gas investigated the possibility of installing a microturbine that could be used to combust ethylene emissions that would otherwise be emitted to the atmosphere. The following summarizes the findings regarding the feasibility and potential benefits of this technology:

(A) The technology for this type of application is unproven. There are no known instances where a system of this type has been utilized on a LNG plant to combust volatile organic compounds.
(B) The period of time during which ethylene emissions would be available for combustion in the turbine would be relatively small, meaning that natural gas would be needed to run the microturbine during other periods including ethylene tank storage.
(C) While a microturbine would control some of the ethylene emissions that occur during the liquefaction process (specifically, those where ethylene would ordinarily be vented to the atmosphere after the process was complete), it could not control other ethylene emissions that might occur during the process.

(c) Rank remaining control technologies by control effectiveness

(1) Recuperative Thermal Incineration, Regenerative Thermal Incineration, Recuperative Catalytic Incineration and Regenerative Catalytic Incineration.

Each control option has an estimated minimum control efficiency of ninety-nine percent (99%) control efficiency for mixed refrigerant VOC used and not sent to the distribution system from the ethylene tank storage. Therefore, each control efficiency is evenly ranked as the most effective control technology.

Citizens Gas claims there are fugitive VOC emissions from the refrigerant compressor seal and numerous valves, flanges and fittings in the liquefaction compressor/heat exchange system. Citizens Gas estimates that the portion of the requested ninety (90) ton VOC emission limit potentially controlled by any one of these control technologies may represent up to eighty percent (80%) of the emission rate or seventy-two (72) tons. However, for the purposes of this review, the total requested amount of ninety (90) tons of VOC emitted from the natural gas liquefaction compressor/heat exchange system shall

be used in evaluating the most effective controls.

(d) Evaluate the most effective controls and document the results

Citizens Gas submitted the following cost analysis for control systems on December 21, 2005, with updated cost information submitted on November 10, 2006, in accordance with the EPA Air Pollution Control Cost Manual (see TSD Appendix C for a detailed cost analysis):

CAPITOL COST

Option	Base Price $	Direct Cost $	Indirect Cost $	Total $
Recuperative Thermal Incineration	441,007	198,453	136,712	776,172
Regenerative Thermal Incineration	817,849	368,032	253,533	1,439,414
Recuperative Catalytic Incineration	637,897	287,053	197,748	1,122,698
Regenerative Catalytic Incineration	1,428,954	643,029	442,976	2,514,958

ANNUAL OPERATING, MAINTENANCE and RECOVERY COST

Option	Direct Cost $	Indirect Cost $	Capitol Recovery Cost $	Total $
Recuperative Thermal Incineration	1,660,974	56,905	102,046	1,819,925
Regenerative Thermal Incineration	668,145	83,425	189,245	940,816
Recuperative Catalytic Incineration	1,242,464	70,779	121,260	1,434,502
Regenerative Catalytic Incineration	544,161	126,474	304,477	975,112

EVALUATION

Option	Total Annualized Cost ($)	Potential Emissions (tons/yr)	Emissions Removed (tons/yr)	Control Efficiency (%)	Total $/ton Emissions Removed
Recuperative Thermal Incineration	1,819,925	90.0	89.1	99.0	20,426
Regenerative Thermal Incineration	940,816	90.0	89.1	99.0	10,559
Recuperative Catalytic Incineration	1,434,502	90.0	89.1	99.0	16,100
Regenerative Catalytic Incineration	975,112	90.0	89.1	99.0	10,944

(e) Select BACT

IDEM, OAQ and OES have evaluated the BACT Analysis submitted by Citizens Gas, the information supplied by vendors/suppliers as part of the submitted analysis, conducted a search of the RBLC information and searched for previous similar determinations in state and local air quality permits. There are no previous determinations in state and local air quality permits for VOC emissions from liquefied natural gas refrigerant compressor/heat exchange systems. In addition, neither ethylene nor any other VOC component of the mixed refrigerant is a hazardous air pollutant. Therefore, IDEM, OAQ and OES conclude that lowest cost figure of $10,559 per ton of VOC removed for this evaluation is cost prohibitive. IDEM, OAQ and OES, propose the following as BACT for VOC emissions from the liquefaction process at Citizens Gas:

Pursuant to 326 IAC 8-1-6, VOC input shall be limited such that the potential to emit of VOC is less than ninety (90.0) tons per twelve (12) consecutive month period with compliance determined at the end of each month.

Ethylene (VOC) input not sent to the natural gas liquefaction compressor/heat exchange system from Emission Unit ID Ethylene Storage Tank shall only be vented into the vapor feed line directly into the natural gas distribution system.

Compliance shall be determined at the end of each month using the following equation:

E = (VOC input, in tons, this month – ethylene (VOC), in tons, this month sent to the natural gas distribution system) + P

Where: E = actual VOC emissions per twelve (12) consecutive month period
P = actual VOC emissions in the previous eleven (11) consecutive month period

APPENDIX C - BACT COST ANALYSIS

Company Name: Citizen's Gas & Coke Utility - LNG North
Address City IN Zip: 4536 West 86th Street, Indianapolis, IN 46268
Permit Number: 097-18805-00141
Reviewer: M. Caraher
Date: November 10, 2006

Direct Capital Costs (A) (see footnote (1))	Basis	Recuperative Thermal Incineration	Regenerative Thermal Incineration	Recuperative Catalytic Incineration	Regenerative Catalytic Incineration
1. Equip Costs (EC)					
Basic Equip (TC)	footnote (1)	$335,109	$684,036	$517,414	$1,143,658
Aux Equip (AE)	Dampers,fan, ductwork	$73,231	$73,231	$73,231	$179,447
2. Instrumentation	included in (AE)	$0	$0	$0	$0
3. Sales Tax & Freight	8% basic equipment cost	$32,667	$60,581	$47,252	$105,848
4. Freight	(included above)	$0	$0	$0	$0
5. Other	NA	$0	$0	$0	$0
6. Purchased Equip Sub (PE)	Sum of 1 thru 5	$441,007	$817,849	$637,897	$1,428,954
		$0	$0	$0	$0
Direct Installation Costs (B) (see footnote (1))		$0	$0	$0	$0
7. Foundations and Supports	8% * (PE)	$35,281	$65,428	$51,032	$114,316
8. Auxiliares	(included in AE above)	$0	$0	$0	$0
9. Handling and Erection	14% * (PE)	$61,741	$114,499	$89,306	$200,054
10. Piping	2% * (PE)	$8,820	$16,357	$12,758	$28,579
11. Insulation and Painting	2% * (PE)	$8,820	$16,357	$12,758	$28,579
12. Electrical	4% * (PE)	$17,640	$32,714	$25,516	$57,158
13. Site Prep	10% * (PE)	$44,101	$81,785	$63,790	$142,895
14. Other (Building)	5% * (PE)	$22,050	$40,892	$31,895	$71,448
15. Direct Installation Costs	Sum of 7 thru 14	$198,453	$368,032	$287,053	$643,029
16. Direct Capital Costs Subtotal	Sum of 1 thru 15	$639,460	$1,185,881	$924,950	$2,071,983
		$0	$0	$0	$0
Indirect Installation Costs (C) (see footnote (1))		$0	$0	$0	$0
1. Engineering and Supervision	10% *(PE)	$44,101	$81,785	$63,790	$142,895
2. Lost Production	NA	$0	$0	$0	$0
3. Construction and Field Expenses	5% * (PE)	$22,050	$40,892	$31,895	$71,448
4. Contractor Fees	10% *(PE)	$44,101	$81,785	$63,790	$142,895
5. Start-up and Performance Tests	3% * (PE)	$13,230	$24,535	$19,137	$42,869
6. Over-all Contingencies	3% * (PE)	$13,230	$24,535	$19,137	$42,869
7. Working Capital	NA	$0	$0	$0	$0
8. Other	NA	$0	$0	$0	$0
9. Indirect Installation Costs Subtotal	Sum of 1 thru 8	$136,712	$253,533	$197,748	$442,976
		$0	$0	$0	$0
Capital Cost Summary (D) (see footnote (1))		$0	$0	$0	$0
1. Total Capital Investment Subtotal (TCC)	(B) + (C)	$776,172	$1,439,414	$1,122,698	$2,514,958
2. Capital Recovery Factor (CRF)	Based on 10% interest with 15 year recovery period	$0	$0	$0	$0
a. Interest Rate		$0	$0	$0	$0
b. Economic Lifetime	15 yr	15 yr	15 yr	15 yr	
3. Capital Recovery Cost	(CRF)*(TCC)	$102,046	$189,245	$121,260	$304,477
		$0	$0	$0	$0
Direct Annual Cost (E) (see footnote (1))		$0	$0	$0	$0
1. Operating Labor		$0	$0	$0	$0
Operator	[(0.5hr/shift)/(8hr/shift)](8760hrs/yr)($25/hr)	$13,688	$13,688	$13,688	$13,688
Supervisor	0.15(Operating Labor)	$2,053	$2,053	$2,053	$2,053
2. Maintenance Labor	[(0.5hr/shift)/(8hr/shift)](8760hrs/yr)($25/hr)	$13,688	$13,688	$13,688	$13,688
3. Materials	equal to maintenance labor cost	$13,688	$13,688	$13,688	$13,688
4. Utilities		$0	$0	$0	$0
Gas	$6.70/1000 scf	$1,584,138	$580,944	$989,777	$278,528
Electric	$0.036/kWh	$33,721	$44,086	$102,662	$116,307
Steam	NA -	-	-	-	
Cooling Water	NA -	-	-	-	
5. Waste Treatment and Disposal	NA	$0	$0	$0	$0
6. Replacement Parts (Catalyst Replace)	Every 2 years for catalyst replacement	$0	$0	$106,909	$106,210
7. Other	NA	$0	$0	$0	$0
8. Direct Annual Cost Subtotal	Sum of 1 thru 7	$1,660,974	$668,145	$1,242,464	$544,161

APPENDIX C - BACT COST

Company Name: Citizen's Gas & Coke Utility - LNG North
Address City IN Zip: 4536 West 86th Street, Indianapolis, IN 46268
Permit Number: 097-18805-00141
Reviewer: M. Caraher
Date: November 10, 2006

		Recuperative Thermal Incineration	Regenerative Thermal Incineration	Recuperative Catalytic Incineration	Regenerative Catalytic Incineration
Indirect Annual Costs (F) (see footnote (1))	Basis				
1. Overhead	60% * (operating + maintenance cost)	$25,869	$25,869	$25,869	$25,869
2. Property Taxes, Admin, insurance	4% * (TCC)	$31,036	$57,556	$44,910	$100,604
3. Other	NA	$0	0	0	0
4. Indirect Annual Costs Subtotal	Sum of 1 thru 3	$56,905	$83,425	$70,779	$126,474
Recovery Credits (G) (see footnote (1))					
1. Mat Recovered	NA	0	0	0	0
2. Energy Recovered	NA	0	0	0	0
3. Other	NA	0	0	0	0
4. Recovery Credits Subtotal	NA	0	0	0	0
Total Annual Cost Summary (H)					
1. Direct Annual Costs Subtotal	Item (E)8. above	$1,660,974	$668,145	$1,242,464	$544,161
2. Indirect Annual Costs Subtotal	Item (F)4. above	$56,905	$83,425	$70,779	$126,474
3. Recovery Credits Subtotal	NA	$0	$0	$0	$0
4. Total Annual Cost Subtotal	Sum of 1 thru 3	$1,717,879	$751,570	$1,313,243	$670,634
Total Annualized Cost Summary (I)					
1. Capital Recovery Cost	Item (D)3. above	$102,046	$189,245	$121,260	$304,477
2. Total Annual Cost Subtotal	Item (H)4. above	$1,717,879	$751,570	$1,313,243	$670,634
3. Total Annualized Cost	Sum of 1 and 2	$1,819,925	$940,816	$1,434,502	$975,112
Cost Effectiveness					
1. Baseline Emission Rate (tons)	estimated rate	90.00	90.00	90.00	90.00
2. Post BACT Emission Rate (tons)	90*(1-control eff)	0.9	0.9	0.9	0.9
3. Total Pollutant Removed (tons)	90*(control eff)	89.10	89.10	89.10	89.10
4. Average Cost Effectiveness of BACT	((I) / 89.10)	$20,426	$10,559	$16,100	$10,944

Notes:

(1) Direct and Indirect Installation costs determined using "EPA Air Pollution Control Cost Manual" Sixth Edition EPA/452/B-02-001 January 2002.

(2) Operating labor cost of $25/hr and Maintenance labor cost of $25/hr do not include benefits.

(3) All cost analysis information is on file at OES as part of the BACT Analysis application and support information received.