Synthetic Minor Determination and/or X Netting Determination

Permit To Install: "02-22027"

A. Source Description

Plant 2 is a Title V facility and is major for particulate emissions (PE), and emissions of nitrogen oxides (NOX), carbon monoxide (CO), sulfur dioxide (SO2) and hazardous air pollutant (HAP) as carbonyl sulfide (COS). The facility makes titanium dioxide (TiO2) pigment powders and TiO2 pigment slurries. Plant 1 (02-04-01-0200) is another Title V TiO2 facility that is major for PE, NOX, CO, SO2 and HAP as COS. Both plants are located on Middle Road in Ashtabula Township, Ashtabula County and share steam and electricity generated at the co-generation turbine-steam boilers (B013-B017) associated with Plant 2. The combination of plants 1 and 2 is considered one major source for federal New Source Review.

B. Emissions and Attainment Status

The combined emissions from Plant 2 and Plant 1 are a major source of PE, NOX, CO, SO2 and HAP as COS, which is also a volatile organic compound (VOC). Ashtabula County is in attainment for the emissions standard for PM10, particulate matter which has a maximum diameter of 10 micrometers. However, Ashtabula Township is in non-attainment for PM2.5, particulate matter which has a maximum diameter of 2.5 micrometers. Ashtabula County is in non-attainment for ozone.

C. Project Emissions

The potential PE rate, and the NOX, CO and VOC emissions, based on a maximum of 4,779 mmft^3 natural gas/yr, are above major source significance levels.

Maximum Potential Emissions for B013-B017 with No Restrictions, Tons/Year			
Pollutant	Maximum Potential	Major Source Significance Level	Classification
PE/PM_{10}	16.73	15	major
SO_2	17.08	40	minor
NO_X	250.33	40	major
CO	260.04	100	major
VOC/OC	44.63	40	major
Formaldehyde, a HAP	1.08	10	minor for MACT

In the application see the "Total" row in the "Maximum Emissions" columns in Table 2 and the "B013-B017" row of the "Potential Emissions" columns in Table 4 on p. 66 & 67, respectively. An emissions credit from the permanent shutdown of boilers and a flyash silo during two overlapping time periods is needed to reduce net NO_X and CO emissions and the PE rate to minor source levels. Such a two-phase netting approach was approved for a combined cycle electric generating unit at a power plant in Louisiana; see Attachment 1 - 12/23/03 U.S. EPA letter to Louisiana Dept. of Environmental Quality.

Phase 1 Netting during 2/09/95 - 1/01/01

The co-generation turbine-steam boilers (B013-B017) at Plant 2 were installed on 1/01/01. The five-year contemporaneous period for the phase 1 netting is 2/09/05 - 1/01/01. The major levels of the PE/PM_{10} rate and the emissions of NO_X, CO, and VOC from the installation of the co-generation turbine-steam boilers (B013-B017) at Plant 2 was offset by the permanent shutdown of natural gas-fired & coal-fired boilers (B003, B004, B009 & B012) at Plant 2. At the time of permit application submittal, the 1/01/01 shutdown of (F003) fly ash silo at Plant 2 was overlooked. The 2/15/01 shutdown of two 69 mmBtu/hr natural gas/oil fuel boilers B001 & B002 at Plant 1 can be classified as an emissions credit. A synthetic minor natural gas fuel usage restriction of 3,590 mmft^3 for the B013-B017 group was proposed and included in PTI 02-13197 to further limit the annual NO_X and CO emissions.

Phase 1 - Emissions for B013-B017 with 3,679 mmft^3/rolling 12-month Restriction & Net Change, Tons/Year					
Pollutant	Restricted Potential	Contemporaneous Changes	Phase 1 Net Change	Major Source Significance Level	Classification
PE/PM_{10}	12.88	-10.81	2.07	15	minor
SO_2	13.15	-810.53	-797.38	40	minor
NO_X	192.75	-152.85	39.90	40	minor
CO	200.22	-101.19	99.03	100	minor
VOC/OC	34.36	-5.86	28.50	40	minor

In the application see the last row of Table 4 and the second column of Table 7 on pp. 67 and 68-B, respectively.

Phase 2 Netting during 3/11/98 - 3/11/03

A 3/11/03 shutdown of a 90 mmBtu/hr natural gas-fired boiler (B005) and a 8.5 mmBtu/hr natural gas-fired steam superheater (B006) associated with B005 at Plant 1 is the end of a five-year contemporaneous period that began on 3/11/98. The increase in the annual, allowable limits for the PE/PM_{10} rate, and emissions of NO_X, CO, SO_2 and OC/VOC from a greater natural gas fuel usage at the co-gen group (B013-B017) at Plant 2 is offset by shutdown of B005 & B006 at Plant 1. The proposed, restricted potential emissions of the co-gen group are already considered in the contemporaneous change evaluation so that an increase in emissions from the co-gen group is projected; see "B013-B017" row in Table 5 on p. 68 of the application. The contemporaneous changes are not added to the co-gen group potential emissions, so that the phase 2 net changes are equivalent to the contemporaneous changes.

Phase 2 - Emissions for B013-B017 with 4,064 $mmft^3$/rolling 12-month Restriction & Net Change, Tons/Year					
Pollutant	Restricted Potential	Contemporaneous Changes	Phase 2 Net Change	Major Source Significance Level	Classification
PE/PM_{10}	14.23	14.43	14.43	15	minor
SO_2	14.53	2.65	2.65	40	minor
NO_X	212.91	39.90	39.90	40	minor
CO	221.17	17.04	17.04	100	minor
VOC/OC	37.96	8.67	8.67	40	minor

D. <u>Conclusion</u>

The Phase 1 period for the installation of the co-gen units (B013-B017) at Plant 2 has minor net changes of criteria pollutants due to emissions credits from the shutdown of B003, B004, B009, B012 and F003 at Plant 2 and the shutdown of B001 & B002 at Plant 1. A natural gas fuel usage restriction of 3,590 $mmft^3$/rolling 12-months for the B013-B017 group is included in PTI 02-13197 to further limit the annual NO_X and CO emissions. Phase 1 is a minor addition of emissions to a major source.

The Phase 2 period is for an increased level of fuel usage to 4,064 $mmft^3$/rolling 12-months for the B013-B017 group at Plant 2. The greater, annual potential emissions will be offset by the shutdown of B005 and B006 at Plant 1 to minor levels of criteria pollutant levels. Phase 2 is the minor addition of emissions to a major source.

The net changes from the combined phases have major levels of NO_X and CO emissions and the PE rate; see Table 7 on p. 68B of the application.

Summary of Net Emissions Changes During Phase 1 and Phase 2 Contemporaneous Periods for B013-B017, Tons/Year			
Pollutant	Phase 1 Net Change	Phase 2 Net Change	Project Total Net Change
PE/PM_{10}	2.07	14.43	16.5
SO_2	-797.38	2.65	-794.73
NO_X	39.90	39.90	79.80
CO	99.03	17.04	116.07
VOC/OC	28.50	8.67	37.17

However, each individual phase is a minor addition to a major source. Therefore, the co-gen project will not be subject to the requirements of the Prevention of Significant Deterioration (PSD) regulations for $PM_{10}/PM_{2.5}$, NO_X and CO emissions.

State of Ohio Environmental Protection Agency

RE: DRAFT PERMIT TO INSTALL
ASHTABULA COUNTY

CERTIFIED MAIL
Millennium Inorganic Chemicals Inc Plt2

Street Address:

Lazarus Gov. Center**TELE:** (614) 644

Application No: 02-22027
Fac ID: 0204010193

Rick Hughes
P.O. Box 310 2426 Middle Rd
Ashtabula, OH 44004

DATE: 6/28/2007

	TOXIC REVIEW
	PSD
Y	SYNTHETIC MINOR
	CEMS
	MACT
Dc and GG	NSPS
	NESHAPS
Y	NETTING
	MAJOR NON-ATTAINMENT
	MODELING SUBMITTED
	GASOLINE DISPENSING FACILITY

You are hereby notified that the Ohio Environmental Protection Agency has made a draft action recommending that the Director issue a Permit to Install for the air contaminant source(s) [emissions unit(s)] shown on the enclosed draft permit. This draft action is not an authorization to begin construction or modification of your emissions unit(s). The purpose of this draft is to solicit public comments on the proposed installation. A public notice concerning the draft permit will appear in the Ohio EPA Weekly Review and the newspaper in the county where the facility will be located. Public comments will be accepted by the field office within 30 days of the date of publication in the newspaper. Any comments you have on the draft permit should be directed to the appropriate field office within the comment period. A copy of your comments should also be mailed to Robert Hodanbosi, Division of Air Pollution Control, Ohio EPA, P.O. Box 1049, Columbus, OH, 43216-1049.

A Permit to Install may be issued in proposed of final form based on the draft action, any written public comments received within 30 days of the public notice, or record of a public meeting if one is held. You will be notified in writing of a scheduled public meeting. Upon issuance of a final Permit to Install a fee of **$4700** will be due. Please do not submit any payment now.

The Ohio EPA is urging companies to investigate pollution prevention and energy conservation. Not only will this reduce pollution and energy consumption, but it can also save you money. If you would like to learn ways you can save money while protecting the environment, please contact our Office of Pollution Prevention at (614) 644-3469. If you have any questions about this draft permit, please contact the field office where you submitted your application, or Mike Ahern, Field Operations & Permit Section at (614) 644-3631.

Sincerely,

Michael W. Ahern

Michael W. Ahern, Manager
Permit Issuance and Data Management Section
Division of Air Pollution Control

CC: **USEPA** **NEDO** **EASTGATE DEV & TRANS STUDY** **NY** **PA**

ASHTABULA COUNTY

PUBLIC NOTICE
ISSUANCE OF DRAFT PERMIT TO INSTALL **02-22027** FOR AN AIR CONTAMINANT SOURCE
FOR **Millennium Inorganic Chemicals Inc Plt2**

On 6/26/2007 the Director of the Ohio Environmental Protection Agency issued a draft action of a Permit To Install an air contaminant source for **Millennium Inorganic Chemicals Inc Plt2**, located at **2426 Middle Rd, Ashtabula**, Ohio.

Installation of the air contaminant source identified below may proceed upon final issuance of Permit To Install 02-22027:

Chapter 31 modification of B013-B017 co-gen units and administrative modification of P001.

Comments concerning this draft action, or a request for a public meeting, must be sent in writing to the address identified below no later than thirty (30) days from the date this notice is published. All inquiries concerning this draft action may be directed to the contact identified below.

Dennis Bush, Ohio EPA, Northeast District Office, 2110 East Aurora Road, Twinsburg, OH 44087
[(330)425-9171]

DRAFT PERMIT TO INSTALL 02-22027

Application Number: 02-22027
Facility ID: 0204010193
Permit Fee: **To be entered upon final issuance**
Name of Facility: Millennium Inorganic Chemicals Inc Plt2
Person to Contact: Rick Hughes
Address: P.O. Box 310 2426 Middle Rd
Ashtabula, OH 44004

Location of proposed air contaminant source(s) [emissions unit(s)]:
2426 Middle Rd
Ashtabula, Ohio

Description of proposed emissions unit(s):
Chapter 31 modification of B013-B017 co-gen units and administrative modification of P001.

The above named entity is hereby granted a Permit to Install for the above described emissions unit(s) pursuant to Chapter 3745-31 of the Ohio Administrative Code. Issuance of this permit does not constitute expressed or implied approval or agreement that, if constructed or modified in accordance with the plans included in the application, the above described emissions unit(s) of environmental pollutants will operate in compliance with applicable State and Federal laws and regulations, and does not constitute expressed or implied assurance that if constructed or modified in accordance with those plans and specifications, the above described emissions unit(s) of pollutants will be granted the necessary permits to operate (air) or NPDES permits as applicable.

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Chris Korleski
Director

A. State and Federally Enforceable Permit-To-Install General Terms and Conditions

1. Monitoring and Related Recordkeeping and Reporting Requirements

a. Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall maintain records that include the following, where applicable, for any required monitoring under this permit:

i. The date, place (as defined in the permit), and time of sampling or measurements.

ii. The date(s) analyses were performed.

iii. The company or entity that performed the analyses.

iv. The analytical techniques or methods used.

v. The results of such analyses.

vi. The operating conditions existing at the time of sampling or measurement.

b. Each record of any monitoring data, testing data, and support information required pursuant to this permit shall be retained for a period of five years from the date the record was created. Support information shall include, but not be limited to, all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Such records may be maintained in computerized form.

c. Except as may otherwise be provided in the terms and conditions for a specific emissions unit, the permittee shall submit required reports in the following manner:

i. Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the appropriate Ohio EPA District Office or local air agency.

ii. Quarterly written reports of (i) any deviations from federally enforceable emission limitations, operational restrictions, and control device operating parameter limitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the appropriate Ohio EPA District Office or local air agency. The written reports shall be submitted (i.e., postmarked) quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See B.9 below if no deviations occurred during the quarter.

iii. Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, and reporting requirements contained in this permit shall be submitted (i.e., postmarked) to the appropriate Ohio EPA District Office or local air agency every six months, by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semi-annual report, which states that no deviations occurred during that period.

iv. If this permit is for an emissions unit located at a Title V facility, then each written report shall be signed by a responsible official certifying that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

d. The permittee shall report actual emissions pursuant to OAC Chapter 3745-78 for the purpose of collecting Air Pollution Control Fees.

2. Scheduled Maintenance/Malfunction Reporting

Any scheduled maintenance of air pollution control equipment shall be performed in accordance with paragraph (A) of OAC rule 3745-15-06. The malfunction, i.e., upset, of any emissions units or any associated air pollution control system(s) shall be reported to the appropriate Ohio EPA District Office or local air agency in accordance with paragraph (B) of OAC rule 3745-15-06. (The definition of an upset condition shall be the same as that used in OAC rule 3745-15-06(B)(1) for a malfunction.) The verbal and written reports shall be submitted pursuant to OAC rule 3745-15-06.

Except as provided in that rule, any scheduled maintenance or malfunction necessitating the shutdown or bypassing of any air pollution control system(s) shall be accompanied by the shutdown of the emission unit(s) that is (are) served by such control system(s).

3. Risk Management Plans

If the permittee is required to develop and register a risk management plan pursuant to section 112(r) of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq. ("Act"), the permittee shall comply with the requirement to register such a plan.

4. Title IV Provisions

If the permittee is subject to the requirements of 40 CFR Part 72 concerning acid rain, the permittee shall ensure that any affected emissions unit complies with those requirements. Emissions exceeding any allowances that are lawfully held under Title IV of the Act, or any regulations adopted thereunder, are prohibited.

5. Severability Clause

A determination that any term or condition of this permit is invalid shall not invalidate the force or effect of any other term or condition thereof, except to the extent that any other term or condition depends in whole or in part for its operation or implementation upon the term or condition declared invalid.

6. General Requirements

a. The permittee must comply with all terms and conditions of this permit. Any noncompliance with the federally enforceable terms and conditions of this permit constitutes a violation of the Act, and is grounds for enforcement action or for permit revocation, revocation and re-issuance, or modification

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 federally enforceable terms and conditions of this permit.

c. This permit may be modified, revoked, or revoked and reissued, for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or revocation, or of a notification of planned changes or anticipated noncompliance does not stay any term and condition of this permit.

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

e. The permittee shall furnish to the Director of the Ohio EPA, or an authorized representative of the Director, upon receipt of a written request and within a reasonable time, any information that may be requested to determine whether cause exists for modifying or revoking this permit or to determine compliance with this permit. Upon request, the permittee shall also furnish to the Director or an authorized representative of the Director, copies of records required to be kept by this permit. For information claimed to be confidential in the submittal to the Director, if the Administrator of the U.S. EPA requests such information, the permittee may furnish such records directly to the Administrator along with a claim of confidentiality.

7. Fees

The permittee shall pay fees to the Director of the Ohio EPA in accordance with ORC section 3745.11 and OAC Chapter 3745-78. The permittee shall pay all applicable permit-to-install fees within 30 days after the issuance of any permit-to-install. The permittee shall pay all applicable permit-to-operate fees within thirty days of the issuance of the invoice.

8. Federal and State Enforceability

Only those terms and conditions designated in this permit as federally enforceable, that are required under the Act, or any its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA and the State and by citizens (to the extent allowed by section 304 of the Act) under the Act. All other terms and conditions of this permit shall not be federally enforceable and shall be enforceable under State law only.

9. Compliance Requirements

a. Any document (including reports) required to be submitted and required by a federally applicable requirement in this permit shall include a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements in the document are true, accurate, and complete.

b. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Director of the Ohio EPA or an authorized representative of the Director to:

i. At reasonable times, enter upon the permittee's premises where a source is located or the emissions-related activity is conducted, or where records must be kept under the conditions of this permit.

ii. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit, subject to the protection from disclosure to the public of confidential information consistent with ORC section 3704.08.

iii. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit.

iv. As authorized by the Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit and applicable requirements.

c. The permittee shall submit progress reports to the appropriate Ohio EPA District Office or local air agency concerning any schedule of compliance for meeting an applicable requirement. Progress reports shall be submitted semiannually, or more frequently if specified in the applicable requirement or by the Director of the Ohio EPA. Progress reports shall contain the following:

i. Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.
ii. An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

10. Permit-To-Operate Application

a. If the permittee is required to apply for a Title V permit pursuant to OAC Chapter 3745-77, the permittee shall submit a complete Title V permit application or a complete Title V permit modification application within twelve (12) months after commencing operation of the emissions units covered by this permit. However, if the proposed new or modified source(s) would be prohibited by the terms and conditions of an existing Title V permit, a Title V permit modification must be obtained before the operation of such new or modified source(s) pursuant to OAC rule 3745-77-04(D) and OAC rule 3745-77-08(C)(3)(d).

b. If the permittee is required to apply for permit(s) pursuant to OAC Chapter 3745-35, the source(s) identified in this permit is (are) permitted to operate for a period of up to one year from the date the source(s) commenced operation. Permission to operate is granted only if the facility complies with all requirements contained in this permit and all applicable air pollution laws, regulations, and policies. Pursuant to OAC Chapter 3745-35, the permittee shall submit a complete operating permit application within ninety (90) days after commencing operation of the source(s) covered by this permit.

11. Best Available Technology

As specified in OAC Rule 3745-31-05, all new sources must employ Best Available Technology (BAT). Compliance with the terms and conditions of this permit will fulfill this requirement.

12. Air Pollution Nuisance

The air contaminants emitted by the emissions units covered by this permit shall not cause a public nuisance, in violation of OAC rule 3745-15-07.

13. Permit-To-Install

A permit-to-install must be obtained pursuant to OAC Chapter 3745-31 prior to "installation" of "any air contaminant source" as defined in OAC rule 3745-31-01, or "modification", as defined in OAC rule 3745-31-01, of any emissions unit included in this permit.

B. State Only Enforceable Permit-To-Install General Terms and Conditions

1. Compliance Requirements

The emissions unit(s) identified in this Permit shall remain in full compliance with all applicable State laws and regulations and the terms and conditions of this permit.

2. Reporting Requirements

The permittee shall submit required reports in the following manner:

a. Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the appropriate Ohio EPA District Office or local air agency.

b. Except as otherwise may be provided in the terms and conditions for a specific emissions unit, quarterly written reports of (a) any deviations (excursions) from state-only required emission limitations, operational restrictions, and control device operating parameter limitations that have been detected by the testing, monitoring, and recordkeeping requirements specified in this permit, (b) the probable cause of such deviations, and (c) any corrective actions or preventive measures which have been or will be taken, shall be submitted to the appropriate Ohio EPA District Office or local air agency. If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted (i.e., postmarked) quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. (These quarterly reports shall exclude deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06.)

3. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The appropriate Ohio EPA District Office or local air agency must be notified in writing

4. Authorization To Install or Modify

If applicable, authorization to install or modify any new or existing emissions unit included in this permit shall terminate within eighteen months of the effective date of the permit if the owner or operator has not undertaken a continuing program of installation or modification or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation or modification. This deadline may be extended by up to 12 months if application is made to the Director within a reasonable time before the termination date and the party shows good cause for any such extension.

5. Construction of New Sources(s)

This permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. This permit does not constitute expressed or implied assurance that the proposed facility has been constructed in accordance with the application and terms and conditions of this permit. The action of beginning and/or completing construction prior to obtaining the Director's approval constitutes a violation of OAC rule 3745-31-02. Furthermore, issuance of this permit does not constitute an assurance that the proposed source will operate in compliance with all Ohio laws and regulations. Issuance of this permit is not to be construed as a waiver of any rights that the Ohio Environmental Protection Agency (or other persons) may have against the applicant for starting construction prior to the effective date of the permit. Additional facilities shall be installed upon orders of the Ohio Environmental Protection Agency if the proposed facilities cannot meet the requirements of this permit or cannot meet applicable standards.

6. Public Disclosure

The facility is hereby notified that this permit, and all agency records concerning the operation of this permitted source, are subject to public disclosure in accordance with OAC rule 3745-49-03.

7. Applicability

This Permit to Install is applicable only to the emissions unit(s) identified in the Permit To Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s).

8. Construction Compliance Certification

If applicable, the applicant shall provide Ohio EPA with a written certification (see enclosed form if applicable) that the facility has been constructed in accordance with the permit-to-install application and the terms and conditions of the permit-to-install. The certification shall be provided to Ohio EPA upon completion of construction but prior to startup of the source.

9. **Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations (See Section A of This Permit)**

   If no deviations occurred during a calendar quarter, the permittee shall submit a quarterly report, which states that no deviations occurred during that quarter. The reports shall be submitted quarterly (i.e., postmarked), by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters.

C. Permit-To-Install Summary of Allowable Emissions

The following information summarizes the total allowable emissions, by pollutant, based on the individual allowable emissions of each air contaminant source identified in this permit.

SUMMARY (for informational purposes only)
TOTAL PERMIT TO INSTALL ALLOWABLE EMISSIONS

Pollutant	Tons Per Year
$N0_x$	240.09
CO	226.91
OC/VOC	39.29
PE/PM_{10}	28.23
$S0_2$	14.53

A. State and Federally Enforceable Permit To Install Facility Specific Terms and Conditions

1. Pursuant to the application for this permit, the terms and conditions in this permit to install are contingent upon the following sequential events occurring:

   a. Phase 1 (2/09/95 - 1/01/01)

      i. the installation, start-up, and initial operation of emissions units B013 through B017 at Plant 2; and

      ii. the permanent shut-down and removal (or removal of a critical piece of operating equipment (boiler feed pump, main steam line, gas supply line, coal feeders, etc.) to render an emissions unit physically inoperable) of the following emissions units:

         (1) B003, B004, B008, B009, B012 and F003 at Plant 2; and

         (2) B001 and B002 at Plant 1.

   b. Phase 2 - 3/11/98 - 3/11/03 - the permanent shut-down and removal (or removal of a critical piece of operating equipment (boiler feed pump, main steam line, gas supply line, coal feeders, etc.) to render an emissions unit physically inoperable) of the following emissions units: B005 and B006 at Plant 1.

2. The permittee shall notify the Ohio EPA is writing of the dates on which installation of emissions units B013 through B017 at Plant 2 commenced and were completed. The permittee shall also notify the Ohio EPA in writing of the dates on which emissions units B003, B004, B008, B009, B012 and F003 at Plant 2 and B001, B002, B005 and B006 at Plant 1 were permanently shut down and removed from the property (or rendered completely inoperable). These notifications shall be submitted to the Northeast District Office within 15 days after an event occurs, or within 30 days of permit issuance if the event has occurred prior to permit issuance.

B. State Only Enforceable Permit To Install Facility Specific Terms and Conditions

None

Emissions Unit ID: B013

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B013) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 2 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
OAC rule 3745-31-05(A)(3)	All Egress Points - Nitrogen oxides (NO_X) emissions shall not exceed 12.53 lbs/hr and 54.88 TPY; see sections A.I.2.a. and A.I.2.b. Carbon monoxide (CO) emissions shall not exceed 12.70 lbs/hr and 55.63 TPY see section A.I.2.c. Organic compound (OC) emissions shall not exceed 2.12 lbs/hr and 9.29 TPY; see section A.I.2.c. Particulate emissions (PE) shall not exceed 0.85 lb/hr and 3.71 TPY; see section A.I.2.e. Sulfur dioxide (SO_2) emissions shall not exceed 0.86 lb/hr and 3.77 TPY. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A) and 3745-21-08(B) and the fuel sulfur content requirements of 40 CFR Part 60, Subpart GG.
OAC rule 3745-17-07(A)(1)	All Egress Points - Visible PE shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
OAC rule 3745-17-10(B)(1)	The PE rate from the duct heater shall not exceed 0.020 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-17-11(B)(4)	The PE rate from the turbine shall not exceed 0.040 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-18-06(F)	SO_2 emissions from the turbine shall not exceed 0.5 lb/mmBtu of actual heat input; see section A.I.2.d.
OAC rule 3745-21-08(B)	See section A.I.2.g.
40 CFR Part 60, Subpart Dc	See section A.I.2.h.

Emissions Unit ID: B013

40 CFR Part 60, Subpart GG	NO_X emissions from the turbine shall not exceed 190.0 parts per million, by volume (ppmv), at 15% oxygen, on a dry basis; see section A.I.2.d. The sulfur content of natural gas burned in the turbine shall not exceed 0.8 percent by weight.
40 CFR Part 63, Subpart YYYY	See section A.VI.3.
40 CFR Part 63, Subpart DDDDD	See section A.VI.4.
OAC rule 3745-31-05(C) - federally enforceable restrictions to avoid PSD requirements.	All Egress Points - The total annual emissions of NO_X and CO from emissions units B013 through B017 shall not exceed 212.91 tons and 221.17 tons, respectively. These annual NO_x and CO emissions limitations shall be achieved by restricting the maximum quantity of natural gas burned to a cumulative total volume of 4,064 million cubic feet based on a rolling 12-month summation.

2. Additional Terms and Conditions

2.a The combustion turbine shall be equipped with a dry, low NO_X emissions combustion system, a low NO_X steam injection system or an equivalent, alternate NO_X emissions control technology.

2.b The allowable rate of 12.53 lbs/hour for NO_X emissions is based on manufacturer's performance guarantees and is established to reflect the potential to emit for this emissions unit.

2.c The allowable rates of 12.70 lbs/hour for CO emissions and 2.12 lbs/hour OC emissions are based on manufacturer's performance guarantees and are established to reflect the potential to emit for this emissions unit.

2.d The emissions limitation(s) specified by this rule is less stringent than the emissions limitation(s) established pursuant to OAC rule 3745-31-05(A)(3).

2.e Per OAC rule 3745-17-10(B), the PE rate from the duct heater portion of this combined cycle unit shall not exceed 0.020 lb/mmBtu. Since the duct burner can not be operated independently of the combustion turbine, the weighted average particulate emissions from this combined cycle emissions unit, when operating at 100 percent load (with total combined cycle heat input of 120.1 mmBtu/hr actual heat input measured at 0^0 F) shall not exceed 0.0308 lb/mmBtu of actual heat input; this is equivalent to an hourly emissions rate of 3.70 pounds at 0^0 Fahrenheit.

2.f These PE rate limitations are equal to or less stringent than the corresponding limitation(s) specified in A.I.2.e.

2.g The permittee shall satisfy the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available technology (BAT) requirements established pursuant to OAC rule 3745-31-05(A)(3) in this permit to install. The design of the emissions unit and the technology associated with the current operating practices satisfy the BAT requirements.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. This rule revision was submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Until the U.S. EPA approves the revision to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

2.h The duct heater is exempted from the SO_2 emissions limits and from the PE limits referenced in 40 CFR Part 60.42c and in 40 CFR Part 60.43c, respectively, as long as this steam generation unit burns only natural gas as a fuel.

II. Operational Restrictions

1. The permittee shall burn only natural gas in this emissions unit.

2. Emissions units B013 through B017 have been in operation for more than 12 months and, as such, the permittee has existing records to generate the rolling, 12-month summation of the natural gas fuel usage rate, upon issuance of this permit. The maximum quantity of natural gas fuel which may be burned in emissions units B013 through B017 shall not exceed 4,064 million cubic feet per year based on a rolling 12-month summation of fuel usage.

3. In accordance with 40 CFR Part 60.333(b), the fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

III. Monitoring and/or Recordkeeping Requirements

1. In accordance with 40 CFR 60.334(h), the permittee shall analyze and maintain records of the fuel-bound sulfur content of the natural gas fuel being fired in the turbine in the following manner:

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a. Monitoring of the sulfur content shall be performed by either the facility, a service contractor retained by the facility, or the fuel supplier.

b. In accordance with 40 CFR 60.334(h)(1), analysis for total sulfur content of the natural gas fuel shall be conducted using the methods described in 40 CFR 60.335(b)(10)(ii). 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, D4404-01, D5228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see 40 CFR 60.17), which measure the major sulfur compound may be used.

c. In accordance with 40 CFR 60.334(h)(3), notwithstanding the provisions of 40 CFR 60.334(h)(1), the permittee 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 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the U.S. EPA administrator for 40 CFR Part 60 subpart GG requires such monitoring. The permittee 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 contact 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 20.0 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 40 CFR.

d. In accordance with 40 CFR 60.334(h)(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 been approved, the owner or operator may, without submitting a special petition to the U.S. EPA administrator, continue monitoring on this schedule. During the first six (6) months of operation of this emissions unit, fuel sulfur content monitoring was performed twice per month. The monitoring data showed little variability in the fuel sulfur content, and indicated consistent compliance with 40 CFR 60.333, so that sampling and analysis for fuel sulfur content shall continue to be conducted once per quarter.

2. For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

3. The permittee shall install, maintain, and operate a properly calibrated natural gas flow rate meter on both the combustion turbine and the duct heater portions of this

emissions unit to allow for accurate determination of the fuel consumption of each portion of this combined cycle unit.

4. The permittee shall maintain monthly records of the following information:

   a. The volume of natural gas burned in this emissions unit for the calendar month (in millions of cubic feet);

   b. The volume of natural gas burned in emissions units B013 through B017 collectively during the month (in millions of cubic feet);

   c. The volume of natural gas burned for the rolling, 12-month summation period for emissions units B013 through B017 collectively;

   d. The number of hours of operation of this emissions unit for each calendar month;

   e. The collective number of hours of operation of emissions units B013 through B017;

   f. An estimate of the NO_X and CO emissions, in tons/month, from this emissions unit based on the compliance methods listed in sections A.V.1.f. and A.V.1.g., respectively, or upon emissions factors developed from the most recent performance/emissions compliance test data; and

   g. An estimate of the NO_X and CO emissions, in tons/month, from emissions units B013 through B017 collectively.

5. The permittee shall maintain daily records of the following information for this emissions unit:

   a. Except as provided in 40 CFR 60.334 (b) on any day when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, the permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. The permittee shall collect and record the following information each day:

      i. the fuel consumption, in cubic feet on an hourly basis;

      ii. the water or steam injection volume, in lbs/hr ;

iii. the hourly ratio of water or steam to fuel;

iv. if applicable, other operating parameter(s) identified in an on-site parameter monitoring plan, required by 40 CFR 60.334(g); and

v. the operating times for the capture (collection) system, control device, monitoring equipment, and the associated emissions unit.

b. In accordance with 40 CFR 60.334 (b) for any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous fuel and steam(water) monitoring system described in 40 CFR 60.334(a), the permittee shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F of 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

i. Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(1) on a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or
(2) on a ppm at 15 percent O_2 basis; or
(3) on a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

ii. As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

iii. For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

(1) For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.334(b)(2), is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under 40 CFR 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in 40 CFR 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(2) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(3) If the owner or operator has installed a NO_X CEMS to meet the requirements of 40 CFR Part 75, and is continuing to meet the ongoing requirements of 40 CFR Part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR Part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c).

c. In accordance with 40 CFR 60.334(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 permittee may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of 40 CFR 60.334(b). Also, if the permittee has previously submitted and received U.S. EPA, or Ohio EPA approval of a procedure for monitoring compliance with the applicable NO_X emissions limit under 40 CFR 60.332, that approved procedure may continue to be used.

IV. Reporting Requirements

1. The permittee shall submit annual deviation reports which identify all periods during which the sulfur content of the fuel fired in this emissions unit exceeded 0.8%, by weight. These reports shall be submitted by January 31 of each year.

2. The permittee shall submit deviation (excursion) reports that identify all periods during which the emissions limitations listed above in these terms and conditions were exceeded or the required records were not maintained. Such report shall be sent to the Northeast District Office within 30 days following the end of the calendar month during which the exceedance or deviation occurred.

3. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

4. The permittee shall submit quarterly deviation (excursion) reports which identify all exceedances of the rolling, 12-month natural gas usage limitation for emissions units B013-B017.

5. Permittee shall submit an annual report which summarizes the monthly and cumulative annual hours of operation of this emissions unit. This report shall be submitted to the Northeast District Office of the Ohio EPA by January 31 of each year for data recorded during the previous calendar year.

6. The permittee shall also submit annual reports which specify the total NO_X emissions and total CO emissions (in tons per year) from this emissions unit for the previous calendar year. These reports shall be submitted by January 31 of each year.

7. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, excess emissions reports shall be submitted in accordance with 40 CFR 60.334(j). An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water fuel ration needed to demonstrate compliance with the NO_X emissions standard in 40 CFR 60.332, as established during the performance test required in 40 CFR 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

   The permittee shall submit quarterly deviation (excursion) reports that identify all periods of time during which the operating parameter(s) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the emissions unit. The quarterly report shall include the following information:

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a. date(s) and time(s) of parameter deviation;

b. average steam or water-to-fuel ratio;

c. average fuel consumption, in cubic feet;

d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

e. gas turbine load, in kilowatts.

The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

8. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, monitor downtime reports shall be submitted in accordance with 40 CFR 60.334(j). A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

   The permittee shall submit semi-annual deviation (excursion) reports that identify all periods of monitor downtime and shall include the following information:

   a. date(s) and time(s) of monitor downtime(s);

   b. average steam or water-to-fuel ratio, if available;

   c. average fuel consumption, in cubic feet;

   d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

   e. gas turbine load, in kilowatts.

   The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

9. The permittee shall submit a notification report 30 days prior to any conversion from a low NO_X steam injection emissions control technology to another NO_X emissions control technology.

V. Testing Requirements

1. Compliance with the emissions limitation(s) and fuel restriction in Sections A.I. and A.II. of these terms and conditions shall be determined in accordance with the following method(s):

    a. Emissions Limitation: Visible particulate emissions from the exhaust stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

    Applicable Compliance Method: If required, compliance shall be determined through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

    b. Emission Limitation: The PE rate from this emissions unit shall not exceed 0.85 lbs/hr and 3.71 TPY.

    Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

    i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0075 lbs/mmBtu as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 3.1, Table 3.1-2a (4/00) to determine an hourly emissions value.

    ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 7.6 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity), to determine an hourly emissions value.

    The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. Compliance with the annual emissions limitation shall be determined by applying

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the calculated hourly emissions limit to the summation of the monthly hours of operation as required by section A.III.4. .

If required pursuant to OAC rule 3745-15-04, the permittee shall demonstrate compliance with the particulate emissions limits of this permit by means of physical testing of the effluent from this emissions unit in accordance with testing procedures listed in 40 CFR Part 60, Appendix A, Methods 1-5.

c. Fuel Sulfur Content Limitation: The gaseous fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

Applicable Compliance Method: Compliance with the fuel sulfur content limitation shall be determined in accordance with the procedures specified in 40 CFR 60.334(h)(1) or 40 CFR 60.334(h)(3) as is required in section A.III.1.-A.III.1.d. If the applicable ranges of some compliance methods in the aforementioned rules are not adequate to measure the levels of sulfur in the gaseous fuel , dilution of samples before analysis (with verification of the dilution ratio) may be conducted, with prior approval from the U.S. EPA Administrator.

d. Emissions Limitations: SO_2 emissions from this emissions unit shall not exceed 0.86 lb/hr and 3.77 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

For the entire emissions unit, multiply the maximum rated heat input capacity of 120.1 mmBtu/hr by an emissions factor of 0.0072 lb/mmBtu, as specified in the application for this permit, to determine an hourly emissions value. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly SO_2 emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

e. Emissions Limitations: OC emissions from this emissions unit shall not exceed 2.12 lbs/hr and 9.29 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0263 lb/mmBtu (per manufacturer's emissions test data supplied by applicant) to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 11 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity) to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

If required, the permittee shall demonstrate compliance with this emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4 and 18, 25 or 25A as appropriate.

f. Emissions Limitations: NOx emissions from this emissions unit shall not exceed 12.53 lbs/hr and 54.88TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.108 lb/mmBtu as specified by manufacturer’s test data for this machine using a low NOx control system to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) by an emissions factor of 0.10 lb/mmBtu as specified in the manufacturer’s guaranteed performance data to determine an hourly emissions value.

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The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly NO_X emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

g. Emissions Limitations: CO emissions from this emissions unit shall not exceed 12.70 lbs/hr and 55.63 TPY.

Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.1316 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 0.0750 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly CO emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

h. Emissions Limitations: NO_x emissions shall not exceed 212.91 TPY and CO emissions shall not exceed 221.17 TPY from emissions units B013 through B017

Applicable Compliance Method: Compliance with the annual emissions limitations for B013 through B017 shall be determined by the summation of monthly emissions from emissions units B013 through B017 collectively, as required by section A.III.4.

2. Emissions Testing Requirements:

   a. Not later than 30 days prior to the proposed test date(s) required in section A.V.2.b., the permittee shall submit an "Intent to Test" notification to the Ohio EPA Northeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA Northeast District Office's refusal to accept the results of the emission test(s).

   b. Within 60 days but not later than 180 days after startup of this emissions unit after the conversion of a NO_X emissions control technology to another NO_X emissions control technology (per 40 CFR 60.8), the permittee shall conduct, or have conducted, performance testing for this emissions unit in accordance with the following requirements:

      i. The emissions testing shall be conducted to demonstrate compliance with the allowable mass emission rates for NO_X, SO_2, and CO.

      ii. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):
      (1) for NO_X , Method 20 of 40 CFR Part 60, Appendix A, ASTM D6522-00 (incorporated by reference, see 40 CFR 60.17), or Method 7E and either EPA Method 3 or 3A of 40 CFR Part 60, Appendix A to determine NO_X and diluent concentration [as specified in 40 CFR 60.335(a)];

      (2) for SO_2, Method 20 or Method 6C of 40 CFR Part 60, Appendix A; and

      (3) for CO, Method 10 of 40 CFR Part 60, Appendix A.
      Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

      iii. The 3-run performance NO_X tests shall be conducted while the combustion turbine portion of this emissions unit is operating within $\pm$ 5 percent at 50, 75, 90 and 100% of peak load or at four other load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-100 percent of peak load, or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. The minimum point and the maximum point turbine operating conditions 3-run sample sets shall be conducted when the duct heater is operating at or near 100% of peak capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice.

iv. A 3-run test for SO_2 emissions shall be conducted while the duct heater portion of this emissions unit is operating at or more than 90% of rated capacity (or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice) while the combustion turbine is also at the highest achievable load point.

v. Two 3-run tests for CO emissions shall be conducted while the combustion turbine portion of the emissions unit is operating at or near 50 and 100% of peak load, or at or near 2 points including the minimum point in the normal operating range of the gas turbine and the highest achievable load point of the gas turbine, while the duct heater is operating at or more than 90% of rated capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. (This testing may be used to establish a CO emissions factor for the combined cycle system.)

vi. In accordance with 40 CFR 60.334(g) the steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of 40 CFR 60.334 shall be monitored during the performance test required under 40 CFR 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to 40 CFR Part 75 and that use the low mass emissions methodology in 40 CFR 75.19 or the NO_X emission measurement methodology in appendix E of 40 CFR Part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in 40 CFR 75.19(e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to 40 CFR Part 75.

c. Personnel from the Ohio EPA Northeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

d. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA Northeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA Northeast District Office.

e. For any conversion of a NO_X emissions control technology to another NO_X emissions control technology, including dry, low NO_X emissions combustion system, additional emissions testing as specified in sections A.V.2.a. - A.V.2.d. shall be required.

VI. Miscellaneous Requirements

1. This emissions unit was initially installed on January 1, 2001 with a low NO_X combustor burner within the combustion turbine. The third administrative permit modification of PTI 02-13197, issued on December 14, 2006, allows the use of steam injection for NO_X emissions control at the turbine.

2. The fuel-bound nitrogen content will be assumed to be zero as long as natural gas fuel is employed in the turbine. Therefore the permittee is exempt from the nitrogen content monitoring of the fuel specified in 40 CFR 60.334(h)(2).

3. Since this emissions unit was installed prior to January 14, 2003, the turbine is considered an "existing stationary combustion turbine" per 40 CFR 63.6090 and is therefore not subject to the formaldehyde concentration exhaust gas limitation(s) within 40 CFR 63.6100. According to 40 CFR 63.6090(a)(3) turbine engine replacement may be considered a reconstructed stationary combustion turbine if it meets the definition of reconstruction in 40 CFR 63.2 of subpart A and if reconstruction commenced after January 14, 2003.

4. The duct heater/recovery boiler is an existing, large, gas fuel fired, watertube boiler as defined in 40 CFR 63.7575 and is therefore subject to only the initial notification requirements of the National Emission Standards for Hazardous Air Pollutants (HAPs) for Industrial, Commercial and Institutional Boilers and Process Heaters 40 CFR Part 63 Subpart DDDDD required by 40 CFR 63.7545.

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B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B013) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology (a dry, low NO_X emissions combustion system, a steam injection system or an equivalent NO_X emissions control technology) and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 2 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

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Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B014) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 3 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
OAC rule 3745-31-05(A)(3)	All Egress Points - Nitrogen oxides (NO_X) emissions shall not exceed 12.53 lbs/hr and 54.88 TPY; see sections A.I.2.a. and A.I.2.b. Carbon monoxide (CO) emissions shall not exceed 12.70 lbs/hr and 55.63 TPY see section A.I.2.c. Organic compound (OC) emissions shall not exceed 2.12 lbs/hr and 9.29 TPY; see section A.I.2.c. Particulate emissions (PE) shall not exceed 0.85 lb/hr and 3.71 TPY; see section A.I.2.e. Sulfur dioxide (SO_2) emissions shall not exceed 0.86 lb/hr and 3.77 TPY. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A) and 3745-21-08(B) and the fuel sulfur content requirements of 40 CFR Part 60, Subpart GG.
OAC rule 3745-17-07(A)(1)	All Egress Points - Visible PE shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
OAC rule 3745-17-10(B)(1)	The PE rate from the duct heater shall not exceed 0.020 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-17-11(B)(4)	The PE rate from the turbine shall not exceed 0.040 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-18-06(F)	SO_2 emissions from the turbine shall not exceed 0.5 lb/mmBtu of actual heat input; see section A.I.2.d.

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OAC rule 3745-21-08(B)	See section A.I.2.g.
40 CFR Part 60, Subpart Dc	See section A.I.2.h.
40 CFR Part 60, Subpart GG	NO_X emissions from the turbine shall not exceed 190.0 parts per million, by volume (ppmv), at 15% oxygen, on a dry basis ; see section A.I.2.d. The sulfur content of natural gas burned in the turbine shall not exceed 0.8 percent by weight ; see section A.I.2.d.
40 CFR Part 63, Subpart YYYY	See section A.VI.3.
40 CFR Part 63, Subpart DDDDD	See section A.VI.4.
OAC rule 3745-31-05(C) - federally enforceable restrictions to avoid PSD requirements.	All Egress Points - The total annual emissions of NO_X and CO from emissions units B013 through B017 shall not exceed 212.91 tons and 221.17 tons, respectively. These annual NO_x and CO emissions limitations shall be achieved by restricting the maximum quantity of natural gas burned to a cumulative total volume of 4,064 million cubic feet based on a rolling 12-month summation.

2. Additional Terms and Conditions

2.a The combustion turbine shall be equipped with a dry, low NO_X emissions combustion system, a low NO_X steam injection system or an equivalent, alternate NO_X emissions control technology.

2.b The allowable rate of 12.53 lbs/hour for NO_X emissions is based on manufacturer's performance guarantees and is established to reflect the potential to emit for this emissions unit.

2.c The allowable rates of 12.70 lbs/hour for CO emissions and 2.12 lbs/hour OC emissions are based on manufacturer's performance guarantees and are established to reflect the potential to emit for this emissions unit.

2.d The emissions limitation(s) specified by this rule is less stringent than the emissions limitation(s) established pursuant to OAC rule 3745-31-05(A)(3).

2.e Per OAC rule 3745-17-10(B), the PE rate from the duct heater portion of this combined cycle unit shall not exceed 0.020 lb/mmBtu. Since the duct burner can not be operated independently of the combustion turbine, the weighted average particulate emissions from this combined cycle emissions unit, when operating at 100 percent load (with total combined cycle heat input of 120.1 mmBtu/hr actual heat input measured at 0^0 F) shall not exceed 0.0308 lb/mmBtu of actual heat input; this is equivalent to an hourly emissions rate of 3.70 pounds at 0^0 Fahrenheit.

2.f These PE rate limitations are equal to or less stringent than the corresponding limitation(s) specified in A.I.2.e.

2.g The permittee shall satisfy the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available technology (BAT) requirements established pursuant to OAC rule 3745-31-05(A)(3) in this permit to install. The design of the emissions unit and the technology associated with the current operating practices satisfy the BAT requirements.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. This rule revision was submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Until the U.S. EPA approves the revision to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

2.h The duct heater is exempted from the SO_2 emissions limits and from the PE limits referenced in 40 CFR Part 60.42c and in 40 CFR Part 60.43c, respectively, as long as this steam generation unit burns only natural gas as a fuel.

II. Operational Restrictions

1. The permittee shall burn only natural gas in this emissions unit.

2. Emissions units B013 through B017 have been in operation for more than 12 months and, as such, the permittee has existing records to generate the rolling, 12-month summation of the natural gas fuel usage rate, upon issuance of this permit. The maximum quantity of natural gas fuel which may be burned in emissions units B013 through B017 shall not exceed 4,064 million cubic feet per year based on a rolling 12-month summation of fuel usage.

3. In accordance with 40 CFR Part 60.333(b), the fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

III. Monitoring and/or Recordkeeping Requirements

1. In accordance with 40 CFR 60.334(h), the permittee shall analyze and maintain records of the fuel-bound sulfur content of the natural gas fuel being fired in the turbine in the following manner:

   a. Monitoring of the sulfur content shall be performed by either the facility, a service contractor retained by the facility, or the fuel supplier.

   b. In accordance with 40 CFR 60.334(h)(1), analysis for total sulfur content of the natural gas fuel shall be conducted using the methods described in 40 CFR 60.335(b)(10)(ii). 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, D4404-01, D5228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see 40 CFR 60.17), which measure the major sulfur compound may be used.

c. In accordance with 40 CFR 60.334(h)(3), notwithstanding the provisions of 40 CFR 60.334(h)(1), the permittee 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 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the U.S. EPA administrator for 40 CFR Part 60 subpart GG requires such monitoring. The permittee 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 contact 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 20.0 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 40 CFR.

d. In accordance with 40 CFR 60.334(h)(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 been approved, the owner or operator may, without submitting a special petition to the U.S. EPA administrator, continue monitoring on this schedule. During the first six (6) months of operation of this emissions unit, fuel sulfur content monitoring was performed twice per month. The monitoring data showed little variability in the fuel sulfur content, and indicated consistent compliance with 40 CFR 60.333, so that sampling and analysis for fuel sulfur content shall be continue to be conducted once per quarter.

2. For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

3. The permittee shall install, maintain, and operate a properly calibrated natural gas flow rate meter on both the combustion turbine and the duct heater portions of this

emissions unit to allow for accurate determination of the fuel consumption of each portion of this combined cycle unit.

4. The permittee shall maintain monthly records of the following information:

   a. The volume of natural gas burned in this emissions unit for the calendar month (in millions of cubic feet);

   b. The volume of natural gas burned in emissions units B013 through B017 collectively during the month (in millions of cubic feet);

   c. The volume of natural gas burned for the rolling, 12-month summation period for emissions units B013 through B017 collectively;

   d. The number of hours of operation of this emissions unit for each calendar month;

   e. The collective number of hours of operation of emissions units B013 through B017;

   f. An estimate of the NO_X and CO emissions, in tons/month, from this emissions unit based on the compliance methods listed in sections A.V.1.f. and A.V.1.g., respectively, or upon emissions factors developed from the most recent performance/emissions compliance test data; and

   g. An estimate of the NO_X and CO emissions, in tons/month, from emissions units B013 through B017 collectively.

5. The permittee shall maintain daily records of the following information for this emissions unit:

   a. Except as provided in 40 CFR 60.334 (b) on any day when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, the permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. The permittee shall collect and record the following information each day:

      i. the fuel consumption, in cubic feet on an hourly basis;

      ii. the water or steam injection volume, in lbs/hr ;

      iii. the hourly ratio of water or steam to fuel;

      iv. if applicable, other operating parameter(s) identified in an on-site parameter monitoring plan, required by 40 CFR 60.334(g); and

v. the operating times for the capture (collection) system, control device, monitoring equipment, and the associated emissions unit.

b. In accordance with 40 CFR 60.334 (b) for any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous fuel and steam(water) monitoring system described in 40 CFR 60.334(a), the permittee shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F of 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

i. Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(1) on a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or
(2) on a ppm at 15 percent O_2 basis; or
(3) on a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

ii. As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

iii. For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

(1) For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.334(b)(2), is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under 40 CFR 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in 40 CFR 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(2) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(3) If the owner or operator has installed a NO_X CEMS to meet the requirements of 40 CFR Part 75, and is continuing to meet the ongoing requirements of 40 CFR Part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR Part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c).

c. In accordance with 40 CFR 60.334(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 permittee may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of 40 CFR 60.334(b). Also, if the permittee has previously submitted and received U.S. EPA, or Ohio EPA approval of a procedure for monitoring compliance with the applicable NO_X emissions limit under 40 CFR 60.332, that approved procedure may continue to be used.

IV. Reporting Requirements

1. The permittee shall submit annual deviation reports which identify all periods during

which the sulfur content of the fuel fired in this emissions unit exceeded 0.8%, by weight. These reports shall be submitted by January 31 of each year.

2. The permittee shall submit deviation (excursion) reports that identify all periods during which the emissions limitations listed above in these terms and conditions were exceeded or the required records were not maintained. Such report shall be sent to the Northeast District Office within 30 days following the end of the calendar month during which the exceedance or deviation occurred.

3. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

4. The permittee shall submit quarterly deviation (excursion) reports which identify all exceedances of the rolling, 12-month natural gas usage limitation for emissions units B013-B017.

5. Permittee shall submit an annual report which summarizes the monthly and cumulative annual hours of operation of this emissions unit. This report shall be submitted to the Northeast District Office of the Ohio EPA by January 31 of each year for data recorded during the previous calendar year.

6. The permittee shall also submit annual reports which specify the total NO_X emissions and total CO emissions (in tons per year) from this emissions unit for the previous calendar year. These reports shall be submitted by January 31 of each year.

7. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, excess emissions reports shall be submitted in accordance with 40 CFR 60.334(j). An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water fuel ration needed to demonstrate compliance with the NO_X emissions standard in 40 CFR 60.332, as established during the performance test required in 40 CFR 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

   The permittee shall submit quarterly deviation (excursion) reports that identify all periods of time during which the operating parameter(s) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the emissions unit. The quarterly report shall include the following information:

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a. date(s) and time(s) of parameter deviation;

b. average steam or water-to-fuel ratio;

c. average fuel consumption, in cubic feet;

d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

e. gas turbine load, in kilowatts.

The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

8. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, monitor downtime reports shall be submitted in accordance with 40 CFR 60.334(j). A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

The permittee shall submit semi-annual deviation (excursion) reports that identify all periods of monitor downtime and shall include the following information:

a. date(s) and time(s) of monitor downtime(s);

b. average steam or water-to-fuel ratio, if available;

c. average fuel consumption, in cubic feet;

d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

e. gas turbine load, in kilowatts.

The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

9. The permittee shall submit a notification report 30 days prior to any conversion from a low NO_X steam injection emissions control technology to another NO_X emissions control technology.

V. Testing Requirements

1. Compliance with the emission limitation(s) and fuel restriction in Sections A.I. and A.II. of these terms and conditions shall be determined in accordance with the following method(s):

   Emission Limitation: Visible particulate emissions from the exhaust stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

   Applicable Compliance Method: If required, compliance shall be determined through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

   b. Emission Limitation: The PE rate from this emissions unit shall not exceed 0.85 lbs/hr and 3.71 TPY.

   Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

   i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0075 lbs/mmBtu as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 3.1, Table 3.1-2a (4/00) to determine an hourly emissions value.

   ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 7.6 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity), to determine an hourly emissions value.

   The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of the monthly hours of operation as required by section A.III.4. .

If required pursuant to OAC rule 3745-15-04, the permittee shall demonstrate compliance with the particulate emissions limits of this permit by means of physical testing of the effluent from this emissions unit in accordance with testing procedures listed in 40 CFR Part 60, Appendix A, Methods 1-5.

c. Fuel Sulfur Content Limitation: The gaseous fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

Applicable Compliance Method: Compliance with the fuel sulfur content limitation shall be determined in accordance with the procedures specified in 40 CFR 60.334(h)(1) or 40 CFR 60.334(h)(3) as is required in section A.III.1.-A.III.1.d. If the applicable ranges of some compliance methods in the aforementioned rules are not adequate to measure the levels of sulfur in the gaseous fuel, dilution of samples before analysis (with verification of the dilution ratio) may be conducted, with prior approval from the U.S. EPA Administrator.

d. Emissions Limitations: SO_2 emissions from this emissions unit shall not exceed 0.86 lb/hr and 3.77 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

For the entire emissions unit, multiply the maximum rated heat input capacity of 120.1 mmBtu/hr by an emissions factor of 0.0072 lb/mmBtu, as specified in the application for this permit, to determine an hourly emissions value. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly SO_2 emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

e. Emissions Limitations: OC emissions from this emissions unit shall not exceed 2.12 lbs/hr and 9.29 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0263 lb/mmBtu (per manufacturer's emissions test data supplied by applicant) to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 11 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity) to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

If required, the permittee shall demonstrate compliance with this emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4 and 18, 25 or 25A as appropriate.

f. Emissions Limitations: NOx emissions from this emissions unit shall not exceed 12.53 lbs/hr and 54.88TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.108 lb/mmBtu as specified by manufacturer's test data for this machine using a low NOx control system to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) by an emissions factor of 0.10 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component

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should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly NO_X emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

g. Emissions Limitations: CO emissions from this emissions unit shall not exceed 12.70 lbs/hr and 55.63 TPY.

Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.1316 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 0.0750 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly CO emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

h. Emissions Limitations: NO_x emissions shall not exceed 212.91 TPY and CO emissions shall not exceed 221.17 TPY from emissions units B013 through B017

Applicable Compliance Method: Compliance with the annual emissions limitations for B013 through B017 shall be determined by the summation of monthly emissions from emissions units B013 through B017 collectively, as required by section A.III.4.

2. Emissions Testing Requirements:

a. Not later than 30 days prior to the proposed test date(s) required in section A.V.2.b., the permittee shall submit an "Intent to Test" notification to the Ohio EPA Northeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA Northeast District Office's refusal to accept the results of the emission test(s).

b. Within 60 days but not later than 180 days after startup of this emissions unit after the conversion of a NO_X emissions control technology to another NO_X emissions control technology (per 40 CFR 60.8), the permittee shall conduct, or have conducted, performance testing for this emissions unit in accordance with the following requirements:

i. The emissions testing shall be conducted to demonstrate compliance with the allowable mass emission rates for NO_X, SO_2, and CO.

ii. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):
(1) for NO_X , Method 20 of 40 CFR Part 60, Appendix A, ASTM D6522-00 (incorporated by reference, see 40 CFR 60.17), or Method 7E and either EPA Method 3 or 3A of 40 CFR Part 60, Appendix A to determine NO_X and diluent concentration [as specified in 40 CFR 60.335(a)];

(2) for SO_2, Method 20 or Method 6C of 40 CFR Part 60, Appendix A; and

(3) for CO, Method 10 of 40 CFR Part 60, Appendix A.
Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

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iii. The 3-run performance NO_X tests shall be conducted while the combustion turbine portion of this emissions unit is operating within ± 5 percent at 50, 75, 90 and 100% of peak load or at four other load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-100 percent of peak load, or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. The minimum point and the maximum point turbine operating conditions 3-run sample sets shall be conducted when the duct heater is operating at or near 100% of peak capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice.

iv. A 3-run test for SO_2 emissions shall be conducted while the duct heater portion of this emissions unit is operating at or more than 90% of rated capacity (or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice) while the combustion turbine is also at the highest achievable load point.

v. Two 3-run tests for CO emissions shall be conducted while the combustion turbine portion of the emissions unit is operating at or near 50 and 100% of peak load, or at or near 2 points including the minimum point in the normal operating range of the gas turbine and the highest achievable load point of the gas turbine, while the duct heater is operating at or more than 90% of rated capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. (This testing may be used to establish a CO emissions factor for the combined cycle system.)

vi. In accordance with 40 CFR 60.334(g) the steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of 40 CFR 60.334 shall be monitored during the performance test required under 40 CFR 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to 40 CFR Part 75 and that use the low mass emissions methodology in 40 CFR 75.19 or the

NO_X emission measurement methodology in appendix E of 40 CFR Part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in 40 CFR 75.19(e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to 40 CFR Part 75.

c. Personnel from the Ohio EPA Northeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

d. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA Northeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA Northeast District Office.

e. For any conversion of a NO_X emissions control technology to another NO_X emissions control technology, including dry, low NO_X emissions combustion system, additional emissions testing as specified in sections A.V.2.a. - A.V.2.d. shall be required.

VI. Miscellaneous Requirements

1. This emissions unit was initially installed on January 1, 2001 with a low NO_X combustor burner within the combustion turbine. This third administrative permit modification allows the use of steam injection for NO_X emissions control at the turbine.

2. The fuel-bound nitrogen content will be assumed to be zero as long as natural gas fuel is employed in the turbine. Therefore the permittee is exempt from the nitrogen content monitoring of the fuel specified in 40 CFR 60.334(h)(2).

3. Since this emissions unit was installed prior to January 14, 2003, the turbine is considered an "existing stationary combustion turbine" per 40 CFR 63.6090 and is therefore not subject to the formaldehyde concentration exhaust gas limitation(s) within 40 CFR 63.6100. According to 40 CFR 63.6090(a)(3) turbine engine replacement may be considered a reconstructed stationary combustion turbine if it meets the definition of reconstruction in 40 CFR 63.2 of subpart A and if reconstruction commenced after

January 14, 2003.

4. The duct heater/recovery boiler is an existing, large, gas fuel fired, watertube boiler as defined in 40 CFR 63.7575 and is therefore subject to only the initial notification requirements of the National Emission Standards for Hazardous Air Pollutants (HAPs) for Industrial, Commercial and Institutional Boilers and Process Heaters 40 CFR Part 63 Subpart DDDDD required by 40 CFR 63.7545.

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B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B014) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 3 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
None	None

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

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Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - **(B015) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 4 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06**

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
OAC rule 3745-31-05(A)(3)	All Egress Points - Nitrogen oxides (NO_X) emissions shall not exceed 12.53 lbs/hr and 54.88 TPY; see sections A.I.2.a. and A.I.2.b. Carbon monoxide (CO) emissions shall not exceed 12.70 lbs/hr and 55.63 TPY see section A.I.2.c. Organic compound (OC) emissions shall not exceed 2.12 lbs/hr and 9.29 TPY; see section A.I.2.c. Particulate emissions (PE) shall not exceed 0.85 lb/hr and 3.71 TPY; see section A.I.2.e. Sulfur dioxide (SO_2) emissions shall not exceed 0.86 lb/hr and 3.77 TPY. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A) and 3745-21-08(B) and the fuel sulfur content requirements of 40 CFR Part 60, Subpart GG.
OAC rule 3745-17-07(A)(1)	All Egress Points - Visible PE shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
OAC rule 3745-17-10(B)(1)	The PE rate from the duct heater shall not exceed 0.020 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-17-11(B)(4)	The PE rate from the turbine shall not exceed 0.040 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-18-06(F)	SO_2 emissions from the turbine shall not exceed 0.5 lb/mmBtu of actual heat input; see section A.I.2.d.

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OAC rule 3745-21-08(B)	See section A.I.2.g.
40 CFR Part 60, Subpart Dc	See section A.I.2.h.
40 CFR Part 60, Subpart GG	NO_X emissions from the turbine shall not exceed 190.0 parts per million, by volume (ppmv), at 15% oxygen, on a dry basis ; see section A.I.2.d. The sulfur content of natural gas burned in the turbine shall not exceed 0.8 percent by weight ; see section A.I.2.d.
40 CFR Part 63, Subpart YYYY	See section A.VI.3.
40 CFR Part 63, Subpart DDDDD	See section A.VI.4.
OAC rule 3745-31-05(C) - federally enforceable restrictions to avoid PSD requirements.	All Egress Points - The total annual emissions of NO_X and CO from emissions units B013 through B017 shall not exceed 212.91 tons and 221.17 tons, respectively. These annual NO_x and CO emissions limitations shall be achieved by restricting the maximum quantity of natural gas burned to a cumulative total volume of 4,064 million cubic feet based on a rolling 12-month summation.

2. Additional Terms and Conditions

2.a The combustion turbine shall be equipped with a dry, low NO_X emissions combustion system, a low NO_X steam injection system or an equivalent, alternate NO_X emissions control technology.

2.b The allowable rate of 12.53 lbs/hour for NO_X emissions is based on manufacturer's performance guarantees and is established to reflect the potential to emit for this emissions unit.

2.c The allowable rates of 12.70 lbs/hour for CO emissions and 2.12 lbs/hour OC emissions are based on manufacturer's performance guarantees and are established to reflect the potential to emit for this emissions unit.

2.d The emissions limitation(s) specified by this rule is less stringent than the emissions limitation(s) established pursuant to OAC rule 3745-31-05(A)(3).

2.e Per OAC rule 3745-17-10(B), the PE rate from the duct heater portion of this combined cycle unit shall not exceed 0.020 lb/mmBtu. Since the duct burner can not be operated independently of the combustion turbine, the weighted average particulate emissions from this combined cycle emissions unit, when operating at 100 percent load (with total combined cycle heat input of 120.1 mmBtu/hr actual heat input measured at 0^0 F) shall not exceed 0.0308 lb/mmBtu of actual heat input; this is equivalent to an hourly emissions rate of 3.70 pounds at 0^0 Fahrenheit.

2.f These PE rate limitations are equal to or less stringent than the corresponding limitation(s) specified in A.I.2.e.

2.g The permittee shall satisfy the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available technology (BAT) requirements established pursuant to OAC rule 3745-31-05(A)(3) in this permit to install. The design of the emissions unit and the technology associated with the current operating practices satisfy the BAT requirements.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. This rule revision was submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Until the U.S. EPA approves the revision to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

2.h The duct heater is exempted from the SO_2 emissions limits and from the PE limits referenced in 40 CFR Part 60.42c and in 40 CFR Part 60.43c, respectively, as long as this steam generation unit burns only natural gas as a fuel.

II. Operational Restrictions

1. The permittee shall burn only natural gas in this emissions unit.

2. Emissions units B013 through B017 have been in operation for more than 12 months and, as such, the permittee has existing records to generate the rolling, 12-month summation of the natural gas fuel usage rate, upon issuance of this permit. The maximum quantity of natural gas fuel which may be burned in emissions units B013 through B017 shall not exceed 4,064 million cubic feet per year based on a rolling 12-month summation of fuel usage.

3. In accordance with 40 CFR Part 60.333(b), the fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

III. Monitoring and/or Recordkeeping Requirements

1. In accordance with 40 CFR 60.334(h), the permittee shall analyze and maintain records of the fuel-bound sulfur content of the natural gas fuel being fired in the turbine in the

following manner:

a. Monitoring of the sulfur content shall be performed by either the facility, a service contractor retained by the facility, or the fuel supplier.

b. In accordance with 40 CFR 60.334(h)(1), analysis for total sulfur content of the natural gas fuel shall be conducted using the methods described in 40 CFR 60.335(b)(10)(ii). 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, D4404-01, D5228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see 40 CFR 60.17), which measure the major sulfur compound may be used.

c. In accordance with 40 CFR 60.334(h)(3), notwithstanding the provisions of 40 CFR 60.334(h)(1), the permittee 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 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the U.S. EPA administrator for 40 CFR Part 60 subpart GG requires such monitoring. The permittee 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 contact 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 20.0 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 40 CFR.

d. In accordance with 40 CFR 60.334(h)(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 been approved, the owner or operator may, without submitting a special petition to the U.S. EPA administrator, continue monitoring on this schedule. During the first six (6) months of operation of this emissions unit, fuel sulfur content monitoring was performed twice per month. The monitoring data showed little variability in the fuel sulfur content, and indicated consistent compliance with 40 CFR 60.333, so that sampling and analysis for fuel sulfur content shall be continue to be conducted once per quarter .

2. For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

3. The permittee shall install, maintain, and operate a properly calibrated natural gas flow

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rate meter on both the combustion turbine and the duct heater portions of this emissions unit to allow for accurate determination of the fuel consumption of each portion of this combined cycle unit.

4. The permittee shall maintain monthly records of the following information:

   a. The volume of natural gas burned in this emissions unit for the calendar month (in millions of cubic feet);

   b. The volume of natural gas burned in emissions units B013 through B017 collectively during the month (in millions of cubic feet);

   c. The volume of natural gas burned for the rolling, 12-month summation period for emissions units B013 through B017 collectively;

   d. The number of hours of operation of this emissions unit for each calendar month;

   e. The collective number of hours of operation of emissions units B013 through B017;

   f. An estimate of the NO_X and CO emissions, in tons/month, from this emissions unit based on the compliance methods listed in sections A.V.1.f. and A.V.1.g., respectively, or upon emissions factors developed from the most recent performance/emissions compliance test data; and

   g. An estimate of the NO_X and CO emissions, in tons/month, from emissions units B013 through B017 collectively.

5. The permittee shall maintain daily records of the following information for this emissions unit:

   a. Except as provided in 40 CFR 60.334 (b) on any day when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, the permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. The permittee shall collect and record the following information each day:

      i. the fuel consumption, in cubic feet on an hourly basis;

      ii. the water or steam injection volume, in lbs/hr

      iii. the hourly ratio of water or steam to fuel;

      iv. if applicable, other operating parameter(s) identified in an on-site parameter monitoring plan, required by 40 CFR 60.334(g); and

v. the operating times for the capture (collection) system, control device, monitoring equipment, and the associated emissions unit.

b. In accordance with 40 CFR 60.334 (b) for any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous fuel and steam(water) monitoring system described in 40 CFR 60.334(a), the permittee shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F of 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

i. Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(1) on a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or
(2) on a ppm at 15 percent O_2 basis; or
(3) on a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

ii. As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

iii. For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

(1) For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.334(b)(2), is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under 40 CFR 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in 40 CFR 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(2) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(3) If the owner or operator has installed a NO_X CEMS to meet the requirements of 40 CFR Part 75, and is continuing to meet the ongoing requirements of 40 CFR Part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR Part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c).

c. In accordance with 40 CFR 60.334(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 permittee may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of 40 CFR 60.334(b). Also, if the permittee has previously submitted and received U.S. EPA, or Ohio EPA approval of a procedure for monitoring compliance with the applicable NO_X emissions limit under 40 CFR 60.332, that approved procedure may continue to be used.

IV. Reporting Requirements

1. The permittee shall submit annual deviation reports which identify all periods during which the sulfur content of the fuel fired in this emissions unit exceeded 0.8%, by weight. These reports shall be submitted by January 31 of each year.

2. The permittee shall submit deviation (excursion) reports that identify all periods during which the emissions limitations listed above in these terms and conditions were exceeded or the required records were not maintained. Such report shall be sent to the Northeast District Office within 30 days following the end of the calendar month during which the exceedance or deviation occurred.

3. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

4. The permittee shall submit quarterly deviation (excursion) reports which identify all exceedances of the rolling, 12-month natural gas usage limitation for emissions units B013-B017.

5. Permittee shall submit an annual report which summarizes the monthly and cumulative annual hours of operation of this emissions unit. This report shall be submitted to the Northeast District Office of the Ohio EPA by January 31 of each year for data recorded during the previous calendar year.

6. The permittee shall also submit annual reports which specify the total NO_X emissions and total CO emissions (in tons per year) from this emissions unit for the previous calendar year. These reports shall be submitted by January 31 of each year.

7. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, excess emissions reports shall be submitted in accordance with 40 CFR 60.334(j). An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water fuel ration needed to demonstrate compliance with the NO_X emissions standard in 40 CFR 60.332, as established during the performance test required in 40 CFR 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

   The permittee shall submit quarterly deviation (excursion) reports that identify all periods of time during which the operating parameter(s) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the emissions unit. The quarterly report shall include the following information:

a. date(s) and time(s) of parameter deviation;

b. average steam or water-to-fuel ratio;

c. average fuel consumption, in cubic feet;

d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

e. gas turbine load, in kilowatts.

The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

8. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, monitor downtime reports shall be submitted in accordance with 40 CFR 60.334(j). A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

   The permittee shall submit semi-annual deviation (excursion) reports that identify all periods of monitor downtime and shall include the following information:

   a. date(s) and time(s) of monitor downtime(s);

   b. average steam or water-to-fuel ratio, if available;

   c. average fuel consumption, in cubic feet;

   d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

   e. gas turbine load, in kilowatts.

   The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

9. The permittee shall submit a notification report 30 days prior to any conversion from a low NO_X steam injection emissions control technology to another NO_X emissions control technology.

V. Testing Requirements

1. Compliance with the emission limitation(s) and fuel restriction in Sections A.I. and A.II. of these terms and conditions shall be determined in accordance with the following method(s):

   a. Emission Limitation: Visible particulate emissions from the exhaust stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

      Applicable Compliance Method: If required, compliance shall be determined through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

   b. Emission Limitation: The PE rate from this emissions unit shall not exceed 0.85 lbs/hr and 3.71 TPY.

      Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

      i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0075 lbs/mmBtu as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 3.1, Table 3.1-2a (4/00) to determine an hourly emissions value.

      ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 7.6 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity), to determine an hourly emissions value.

      The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit.

Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of the monthly hours of operation as required by section A.III.4. .

If required pursuant to OAC rule 3745-15-04, the permittee shall demonstrate compliance with the particulate emissions limits of this permit by means of physical testing of the effluent from this emissions unit in accordance with testing procedures listed in 40 CFR Part 60, Appendix A, Methods 1-5.

c. Fuel Sulfur Content Limitation: The gaseous fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

Applicable Compliance Method: Compliance with the fuel sulfur content limitation shall be determined in accordance with the procedures specified in 40 CFR 60.334(h)(1) or 40 CFR 60.334(h)(3) as is required in section A.III.1.-A.III.1.d. If the applicable ranges of some compliance methods in the aforementioned rules are not adequate to measure the levels of sulfur in the gaseous fuel , dilution of samples before analysis (with verification of the dilution ratio) may be conducted, with prior approval from the U.S. EPA Administrator.

d. Emissions Limitations: SO_2 emissions from this emissions unit shall not exceed 0.86 lb/hr and 3.77 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

For the entire emissions unit, multiply the maximum rated heat input capacity of 120.1 mmBtu/hr by an emissions factor of 0.0072 lb/mmBtu, as specified in the application for this permit, to determine an hourly emissions value. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly SO_2 emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

e. Emissions Limitations: OC emissions from this emissions unit shall not exceed 2.12 lbs/hr and 9.29 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0263 lb/mmBtu (per manufacturer's emissions test data supplied by applicant) to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 11 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity) to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

If required, the permittee shall demonstrate compliance with this emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4 and 18, 25 or 25A as appropriate.

f. Emissions Limitations: NOx emissions from this emissions unit shall not exceed 12.53 lbs/hr and 54.88 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.108 lb/mmBtu as specified by manufacturer's test data for this machine using a low NOx control system to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) by an emissions factor of 0.10 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly NO_X emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

g. Emissions Limitations: CO emissions from this emissions unit shall not exceed 12.70 lbs/hr and 55.63 TPY.

Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.1316 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 0.0750 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly CO emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

h. Emissions Limitations: NO_x emissions shall not exceed 212.91 TPY and CO emissions shall not exceed 221.17 TPY from emissions units B013 through B017

Applicable Compliance Method: Compliance with the annual emissions limitations for B013 through B017 shall be determined by the summation of monthly emissions from emissions units B013 through B017 collectively, as required by section A.III.4.

2. Emissions Testing Requirements:

a. Not later than 30 days prior to the proposed test date(s) required in section A.V.2.b., the permittee shall submit an "Intent to Test" notification to the Ohio EPA Northeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA Northeast District Office's refusal to accept the results of the emission test(s).

b. Within 60 days but not later than 180 days after startup of this emissions unit after the conversion of a NO_X emissions control technology to another NO_X emissions control technology (per 40 CFR 60.8), the permittee shall conduct, or have conducted, performance testing for this emissions unit in accordance with the following requirements:

i. The emissions testing shall be conducted to demonstrate compliance with the allowable mass emission rates for NO_X, SO_2, and CO.

ii. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):
(1) for NO_X , Method 20 of 40 CFR Part 60, Appendix A, ASTM D6522-00 (incorporated by reference, see 40 CFR 60.17), or Method 7E and either EPA Method 3 or 3A of 40 CFR Part 60, Appendix A to determine NO_X and diluent concentration [as specified in 40 CFR 60.335(a)];

(2) for SO_2, Method 20 or Method 6C of 40 CFR Part 60, Appendix A; and

(3) for CO, Method 10 of 40 CFR Part 60, Appendix A.
Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

iii. The 3-run performance NO_X tests shall be conducted while the combustion turbine portion of this emissions unit is operating within $\pm$ 5 percent at 50, 75, 90 and 100% of peak load or at four other load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-100 percent of peak load, or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. The minimum point and the maximum point turbine operating conditions 3-run sample sets shall be conducted when the duct heater is operating at or near 100% of peak capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice.

iv. A 3-run test for SO_2 emissions shall be conducted while the duct heater portion of this emissions unit is operating at or more than 90% of rated capacity (or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice) while the combustion turbine is also at the highest achievable load point.

v. Two 3-run tests for CO emissions shall be conducted while the combustion turbine portion of the emissions unit is operating at or near 50 and 100% of peak load, or at or near 2 points including the minimum point in the normal operating range of the gas turbine and the highest achievable load point of the gas turbine, while the duct heater is operating at or more than 90% of rated capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. (This testing may be used to establish a CO emissions factor for the combined cycle system.)

vi. In accordance with 40 CFR 60.334(g) the steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of 40 CFR 60.334 shall be monitored during the performance test required under 40 CFR 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to 40 CFR Part 75 and that use the low mass emissions methodology in 40 CFR 75.19 or the NO_X emission measurement methodology in appendix E of 40 CFR Part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in 40 CFR 75.19(e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to 40 CFR Part 75.

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c. Personnel from the Ohio EPA Northeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

d. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA Northeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA Northeast District Office.

e. For any conversion of a NO_X emissions control technology to another NO_X emissions control technology, including dry, low NO_X emissions combustion system, additional emissions testing as specified in sections A.V.2.a. - A.V.2.d. shall be required.

VI. Miscellaneous Requirements

1. This emissions unit was initially installed on January 1, 2001 with a low NO_X combustor burner within the combustion turbine. This third administrative permit modification allows the use of steam injection for NO_X emissions control at the turbine.

2. The fuel-bound nitrogen content will be assumed to be zero as long as natural gas fuel is employed in the turbine. Therefore the permittee is exempt from the nitrogen content monitoring of the fuel specified in 40 CFR 60.334(h)(2).

3. Since this emissions unit was installed prior to January 14, 2003, the turbine is considered an "existing stationary combustion turbine" per 40 CFR 63.6090 and is therefore not subject to the formaldehyde concentration exhaust gas limitation(s) within 40 CFR 63.6100. According to 40 CFR 63.6090(a)(3) turbine engine replacement may be considered a reconstructed stationary combustion turbine if it meets the definition of reconstruction in 40 CFR 63.2 of subpart A and if reconstruction commenced after January 14, 2003.

4. The duct heater/recovery boiler is an existing, large, gas fuel fired, watertube boiler as defined in 40 CFR 63.7575 and is therefore subject to only the initial notification requirements of the National Emission Standards for Hazardous Air Pollutants (HAPs) for Industrial, Commercial and Institutional Boilers and Process Heaters 40 CFR Part 63 Subpart DDDDD required by 40 CFR 63.7545.

Emissions Unit ID: B015

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B015) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 4 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
None	None

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Issued: To be entered upon final issuance
Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B016) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 5 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
OAC rule 3745-31-05(A)(3)	All Egress Points - Nitrogen oxides (NO_X) emissions shall not exceed 12.53 lbs/hr and 54.88 TPY; see sections A.I.2.a. and A.I.2.b. Carbon monoxide (CO) emissions shall not exceed 12.70 lbs/hr and 55.63 TPY see section A.I.2.c. Organic compound (OC) emissions shall not exceed 2.12 lbs/hr and 9.29 TPY; see section A.I.2.c. Particulate emissions (PE) shall not exceed 0.85 lb/hr and 3.71 TPY; see section A.I.2.e. Sulfur dioxide (SO_2) emissions shall not exceed 0.86 lb/hr and 3.77 TPY. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A) and 3745-21-08(B) and the fuel sulfur content requirements of 40 CFR Part 60, Subpart GG.
OAC rule 3745-17-07(A)(1)	All Egress Points - Visible PE shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
OAC rule 3745-17-10(B)(1)	The PE rate from the duct heater shall not exceed 0.020 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-17-11(B)(4)	The PE rate from the turbine shall not exceed 0.040 lb/mmBtu of actual heat input; see section A.I.2.f.
OAC rule 3745-18-06(F)	SO_2 emissions from the turbine shall not exceed 0.5 lb/mmBtu of actual heat input; see section A.I.2.d.

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OAC rule 3745-21-08(B)	See section A.I.2.g.
40 CFR Part 60, Subpart Dc	See section A.I.2.h.
40 CFR Part 60, Subpart GG	NO_X emissions from the turbine shall not exceed 190.0 parts per million, by volume (ppmv), at 15% oxygen, on a dry basis ; see section A.I.2.d. The sulfur content of natural gas burned in the turbine shall not exceed 0.8 percent by weight ; see section A.I.2.d.
40 CFR Part 63, Subpart YYYY	See section A.VI.3.
40 CFR Part 63, Subpart DDDDD	See section A.VI.4.
OAC rule 3745-31-05(C) - federally enforceable restrictions to avoid PSD requirements.	All Egress Points - The total annual emissions of NO_X and CO from emissions units B013 through B017 shall not exceed 212.91 tons and 221.17 tons, respectively. These annual NO_x and CO emissions limitations shall be achieved by restricting the maximum quantity of natural gas burned to a cumulative total volume of 4,064 million cubic feet based on a rolling 12-month summation.

2. Additional Terms and Conditions

2.a The combustion turbine shall be equipped with a dry, low NO_X emissions combustion system, a low NO_X steam injection system or an equivalent, alternate NO_X emissions control technology.

2.b The allowable rate of 12.53 lbs/hour for NO_X emissions is based on manufacturer's performance guarantees and is established to reflect the potential to emit for this emissions unit.

2.c The allowable rates of 12.70 lbs/hour for CO emissions and 2.12 lbs/hour OC emissions are based on manufacturer's performance guarantees and are established to reflect the potential to emit for this emissions unit.

2.d The emissions limitation(s) specified by this rule is less stringent than the emissions limitation(s) established pursuant to OAC rule 3745-31-05(A)(3).

2.e Per OAC rule 3745-17-10(B), the PE rate from the duct heater portion of this combined cycle unit shall not exceed 0.020 lb/mmBtu. Since the duct burner can not be operated independently of the combustion turbine, the weighted average particulate emissions from this combined cycle emissions unit, when operating at 100 percent load (with total combined cycle heat input of 120.1 mmBtu/hr actual heat input measured at 0^0 F) shall not exceed 0.0308 lb/mmBtu of actual heat input; this is equivalent to an hourly emissions rate of 3.70 pounds at 0^0 Fahrenheit.

2.f These PE rate limitations are equal to or less stringent than the corresponding limitation(s) specified in A.I.2.e.

2.g The permittee shall satisfy the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available technology (BAT) requirements established pursuant to OAC rule 3745-31-05(A)(3) in this permit to install. The design of the emissions unit and the technology associated with the current operating practices satisfy the BAT requirements.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. This rule revision was submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Until the U.S. EPA approves the revision to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

2.h The duct heater is exempted from the SO_2 emissions limits and from the PE limits referenced in 40 CFR Part 60.42c and in 40 CFR Part 60.43c, respectively, as long as this steam generation unit burns only natural gas as a fuel.

II. Operational Restrictions

1. The permittee shall burn only natural gas in this emissions unit.

2. Emissions units B013 through B017 have been in operation for more than 12 months and, as such, the permittee has existing records to generate the rolling, 12-month summation of the natural gas fuel usage rate, upon issuance of this permit. The maximum quantity of natural gas fuel which may be burned in emissions units B013 through B017 shall not exceed 4,064 million cubic feet per year based on a rolling 12-month summation of fuel usage.

3. In accordance with 40 CFR Part 60.333(b), the fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

III. Monitoring and/or Recordkeeping Requirements

1. In accordance with 40 CFR 60.334(h), the permittee shall analyze and maintain records of the fuel-bound sulfur content of the natural gas fuel being fired in the turbine in the

following manner:

a. Monitoring of the sulfur content shall be performed by either the facility, a service contractor retained by the facility, or the fuel supplier.

b. In accordance with 40 CFR 60.334(h)(1), analysis for total sulfur content of the natural gas fuel shall be conducted using the methods described in 40 CFR 60.335(b)(10)(ii). 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, D4404-01, D5228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see 40 CFR 60.17), which measure the major sulfur compound may be used.

c. In accordance with 40 CFR 60.334(h)(3), notwithstanding the provisions of 40 CFR 60.334(h)(1), the permittee 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 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the U.S. EPA administrator for 40 CFR Part 60 subpart GG requires such monitoring. The permittee 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 contact 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 20.0 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 40 CFR.

d. In accordance with 40 CFR 60.334(h)(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 been approved, the owner or operator may, without submitting a special petition to the U.S. EPA administrator, continue monitoring on this schedule. During the first six (6) months of operation of this emissions unit, fuel sulfur content monitoring was performed twice per month. The monitoring data showed little variability in the fuel sulfur content, and indicated consistent compliance with 40 CFR 60.333, so that sampling and analysis for fuel sulfur content shall be continue to be conducted once per quarter .

2. For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

3. The permittee shall install, maintain, and operate a properly calibrated natural gas flow

rate meter on both the combustion turbine and the duct heater portions of this emissions unit to allow for accurate determination of the fuel consumption of each portion of this combined cycle unit.

4. The permittee shall maintain monthly records of the following information:

   a. The volume of natural gas burned in this emissions unit for the calendar month (in millions of cubic feet);

   b. The volume of natural gas burned in emissions units B013 through B017 collectively during the month (in millions of cubic feet);

   c. The volume of natural gas burned for the rolling, 12-month summation period for emissions units B013 through B017 collectively;

   d. The number of hours of operation of this emissions unit for each calendar month;

   e. The collective number of hours of operation of emissions units B013 through B017;

   f. An estimate of the NO_X and CO emissions, in tons/month, from this emissions unit based on the compliance methods listed in sections A.V.1.f. and A.V.1.g., respectively, or upon emissions factors developed from the most recent performance/emissions compliance test data; and

   g. An estimate of the NO_X and CO emissions, in tons/month, from emissions units B013 through B017 collectively.

5. The permittee shall maintain daily records of the following information for this emissions unit:

   a. Except as provided in 40 CFR 60.334 (b) on any day when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, the permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. The permittee shall collect and record the following information each day:

      i. the fuel consumption, in cubic feet on an hourly basis;

      ii. the water or steam injection volume, in lbs/hr

      iii. the hourly ratio of water or steam to fuel;

iv. if applicable, other operating parameter(s) identified in an on-site parameter monitoring plan, required by 40 CFR 60.334(g); and

v. the operating times for the capture (collection) system, control device, monitoring equipment, and the associated emissions unit.

b. In accordance with 40 CFR 60.334 (b) for any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous fuel and steam(water) monitoring system described in 40 CFR 60.334(a), the permittee shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F of 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

i. Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(1) on a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or
(2) on a ppm at 15 percent O_2 basis; or
(3) on a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

ii. As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

iii. For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

(1) For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.334(b)(2), is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under 40 CFR 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in 40 CFR 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(2) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(3) If the owner or operator has installed a NO_X CEMS to meet the requirements of 40 CFR Part 75, and is continuing to meet the ongoing requirements of 40 CFR Part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR Part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c).

c. In accordance with 40 CFR 60.334(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 permittee may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of 40 CFR 60.334(b). Also, if the permittee has previously submitted and received U.S. EPA, or Ohio EPA approval of a procedure for monitoring compliance with the applicable NO_X emissions limit under 40 CFR 60.332, that approved procedure may continue to be used.

IV. Reporting Requirements

1. The permittee shall submit annual deviation reports which identify all periods during which the sulfur content of the fuel fired in this emissions unit exceeded 0.8%, by weight. These reports shall be submitted by January 31 of each year.

2. The permittee shall submit deviation (excursion) reports that identify all periods during which the emissions limitations listed above in these terms and conditions were exceeded or the required records were not maintained. Such report shall be sent to the Northeast District Office within 30 days following the end of the calendar month during which the exceedance or deviation occurred.

3. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

4. The permittee shall submit quarterly deviation (excursion) reports which identify all exceedances of the rolling, 12-month natural gas usage limitation for emissions units B013-B017.

5. Permittee shall submit an annual report which summarizes the monthly and cumulative annual hours of operation of this emissions unit. This report shall be submitted to the Northeast District Office of the Ohio EPA by January 31 of each year for data recorded during the previous calendar year.

6. The permittee shall also submit annual reports which specify the total NO_X emissions and total CO emissions (in tons per year) from this emissions unit for the previous calendar year. These reports shall be submitted by January 31 of each year.

7. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, excess emissions reports shall be submitted in accordance with 40 CFR 60.334(j). An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water fuel ration needed to demonstrate compliance with the NO_X emissions standard in 40 CFR 60.332, as established during the performance test required in 40 CFR 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

   The permittee shall submit quarterly deviation (excursion) reports that identify all periods of time during which the operating parameter(s) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the emissions unit. The quarterly report shall include the following information:

a. date(s) and time(s) of parameter deviation;

b. average steam or water-to-fuel ratio;

c. average fuel consumption, in cubic feet;

d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

e. gas turbine load, in kilowatts.

The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

8. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, monitor downtime reports shall be submitted in accordance with 40 CFR 60.334(j). A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

   The permittee shall submit semi-annual deviation (excursion) reports that identify all periods of monitor downtime and shall include the following information:

   a. date(s) and time(s) of monitor downtime(s);

   b. average steam or water-to-fuel ratio, if available;

   c. average fuel consumption, in cubic feet;

   d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

   e. gas turbine load, in kilowatts.

   The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

9. The permittee shall submit a notification report 30 days prior to any conversion from a low NO_X steam injection emissions control technology to another NO_X emissions control technology.

V. Testing Requirements

1. Compliance with the emission limitation(s) and fuel restriction in Sections A.I. and A.II. of these terms and conditions shall be determined in accordance with the following method(s):

   a. Emission Limitation: Visible particulate emissions from the exhaust stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

      Applicable Compliance Method: If required, compliance shall be determined through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

   b. Emission Limitation: The PE rate from this emissions unit shall not exceed 0.85 lbs/hr and 3.71 TPY.

      Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

      i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0075 lbs/mmBtu as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 3.1, Table 3.1-2a (4/00) to determine an hourly emissions value.

      ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 7.6 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity), to determine an hourly emissions value.

      The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of the monthly hours of operation as required by section A.III.4. .

If required pursuant to OAC rule 3745-15-04, the permittee shall demonstrate compliance with the particulate emissions limits of this permit by means of physical testing of the effluent from this emissions unit in accordance with testing procedures listed in 40 CFR Part 60, Appendix A, Methods 1-5.

c. Fuel Sulfur Content Limitation: The gaseous fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

Applicable Compliance Method: Compliance with the fuel sulfur content limitation shall be determined in accordance with the procedures specified in 40 CFR 60.334(h)(1) or 40 CFR 60.334(h)(3) as is required in section A.III.1.-A.III.1.d. If the applicable ranges of some compliance methods in the aforementioned rules are not adequate to measure the levels of sulfur in the gaseous fuel , dilution of samples before analysis (with verification of the dilution ratio) may be conducted, with prior approval from the U.S. EPA Administrator.

d. Emissions Limitations: SO_2 emissions from this emissions unit shall not exceed 0.86 lb/hr and 3.77 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

For the entire emissions unit, multiply the maximum rated heat input capacity of 120.1 mmBtu/hr by an emissions factor of 0.0072 lb/mmBtu, as specified in the application for this permit, to determine an hourly emissions value. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly SO_2 emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

e. Emissions Limitations: OC emissions from this emissions unit shall not exceed 2.12 lbs/hr and 9.29 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0263 lb/mmBtu (per manufacturer's emissions test data supplied by applicant) to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 11 lbs/million cubic feet of fuel burned as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 1.4, Table 1.4-1 & 2 (7/98) (for industrial boilers of less than 100 mmBtu/hr heat input capacity) to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

If required, the permittee shall demonstrate compliance with this emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4 and 18, 25 or 25A as appropriate.

f. <u>Emissions Limitations</u>: NOx emissions from this emissions unit shall not exceed 12.53 lbs/hr and 54.88TPY.

<u>Applicable Compliance Method</u>: Compliance with these emissions limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.108 lb/mmBtu as specified by manufacturer's test data for this machine using a low NOx control system to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) by an emissions factor of 0.10 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly NO_X emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

g. Emissions Limitations: CO emissions from this emissions unit shall not exceed 12.70 lbs/hr and 55.63 TPY.

Applicable Compliance Method: Compliance with these emission limitations may be determined in the following manner:

i. For the combustion turbine portion of this emissions unit, multiply the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.1316 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

ii. For the duct heater portion of this emissions unit, multiply the maximum hourly fuel usage, as determined using the maximum rated heat input capacity of the emissions unit (55.0 mmBtu/hr) and a figure of 1000 Btu/cubic foot for the caloric value of natural gas, by an emissions factor of 0.0750 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value.

The calculated hourly emissions for the combustion turbine component should then be added to the calculated emissions for the duct heater component of this emissions unit to determine the compliance value for the entire emissions unit. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly CO emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

h. Emissions Limitations: NO_x emissions shall not exceed 212.91 TPY and CO emissions shall not exceed 221.17 TPY from emissions units B013 through B017

Applicable Compliance Method: Compliance with the annual emissions limitations for B013 through B017 shall be determined by the summation of monthly emissions from emissions units B013 through B017 collectively, as required by section A.III.4.

2. Emissions Testing Requirements:

a. Not later than 30 days prior to the proposed test date(s) required in section A.V.2.b., the permittee shall submit an "Intent to Test" notification to the Ohio EPA Northeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA Northeast District Office's refusal to accept the results of the emission test(s).

b. Within 60 days but not later than 180 days after startup of this emissions unit after the conversion of a NO_X emissions control technology to another NO_X emissions control technology (per 40 CFR 60.8), the permittee shall conduct, or have conducted, performance testing for this emissions unit in accordance with the following requirements:

i. The emissions testing shall be conducted to demonstrate compliance with the allowable mass emission rates for NO_X, SO_2, and CO.

ii. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):
(1) for NO_X , Method 20 of 40 CFR Part 60, Appendix A, ASTM D6522-00 (incorporated by reference, see 40 CFR 60.17), or Method 7E and either EPA Method 3 or 3A of 40 CFR Part 60, Appendix A to determine NO_X and diluent concentration [as specified in 40 CFR 60.335(a)];

(2) for SO_2, Method 20 or Method 6C of 40 CFR Part 60, Appendix A; and

(3) for CO, Method 10 of 40 CFR Part 60, Appendix A.
Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

iii. The 3-run performance NO_X tests shall be conducted while the combustion turbine portion of this emissions unit is operating within $\pm$ 5 percent at 50, 75, 90 and 100% of peak load or at four other load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-100 percent of peak load, or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. The minimum point and the maximum point turbine operating conditions 3-run sample sets shall be conducted when the duct heater is operating at or near 100% of peak capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice.

iv. A 3-run test for SO_2 emissions shall be conducted while the duct heater portion of this emissions unit is operating at or more than 90% of rated capacity (or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice) while the combustion turbine is also at the highest achievable load point.

v. Two 3-run tests for CO emissions shall be conducted while the combustion turbine portion of the emissions unit is operating at or near 50 and 100% of peak load, or at or near 2 points including the minimum point in the normal operating range of the gas turbine and the highest achievable load point of the gas turbine, while the duct heater is operating at or more than 90% of rated capacity or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice. (This testing may be used to establish a CO emissions factor for the combined cycle system.)

vi. In accordance with 40 CFR 60.334(g) the steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of 40 CFR 60.334 shall be monitored during the performance test required under 40 CFR 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to 40 CFR Part 75 and that use the low mass emissions methodology in 40 CFR 75.19 or the

NO_X emission measurement methodology in appendix E of 40 CFR Part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in 40 CFR 75.19(e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to 40 CFR Part 75.

c. Personnel from the Ohio EPA Northeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

d. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA Northeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA Northeast District Office.

e. For any conversion of a NO_X emissions control technology to another NO_X emissions control technology, including dry, low NO_X emissions combustion system, additional emissions testing as specified in sections A.V.2.a. - A.V.2.d. shall be required.

VI. Miscellaneous Requirements

1. This emissions unit was initially installed on January 1, 2001 with a low NO_X combustor burner within the combustion turbine. This third administrative permit modification allows the use of steam injection for NO_X emissions control at the turbine.

2. The fuel-bound nitrogen content will be assumed to be zero as long as natural gas fuel is employed in the turbine. Therefore the permittee is exempt from the nitrogen content monitoring of the fuel specified in 40 CFR 60.334(h)(2).

3. Since this emissions unit was installed prior to January 14, 2003, the turbine is considered an "existing stationary combustion turbine" per 40 CFR 63.6090 and is therefore not subject to the formaldehyde concentration exhaust gas limitation(s) within 40 CFR 63.6100. According to 40 CFR 63.6090(a)(3) turbine engine replacement may be considered a reconstructed stationary combustion turbine if it meets the definition of reconstruction in 40 CFR 63.2 of subpart A and if reconstruction commenced after

January 14, 2003.

4. The duct heater/recovery boiler is an existing, large, gas fuel fired, watertube boiler as defined in 40 CFR 63.7575 and is therefore subject to only the initial notification requirements of the National Emission Standards for Hazardous Air Pollutants (HAPs) for Industrial, Commercial and Institutional Boilers and Process Heaters 40 CFR Part 63 Subpart DDDDD required by 40 CFR 63.7545.

Issued: To be entered upon final issuance

B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B016) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a 55.0 mmBtu/hr natural gas-fired duct heater/heat recovery boiler no. 5 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
None	None

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment -(B017) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a heat recovery steam generator no. 1 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
OAC rule 3745-31-05(A)(3)	All Egress Points - Nitrogen oxides (NO_X) emissions shall not exceed 7.03 lbs/hr and 30.79 TPY; see sections A.I.2.a. and A.I.2.b. Carbon monoxide (CO) emissions shall not exceed 8.57 lbs/hr and 37.54 TPY see section A.I.2.c. Organic compound (OC) emissions shall not exceed 0.46 lbs/hr and 7.49 TPY; see section A.I.2.c. Particulate emissions (PE) shall not exceed 0.43 lb/hr and 1.88 TPY. Sulfur dioxide (SO_2) emissions shall not exceed 0.46 lb/hr and 2.01 TPY. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-07(A) and 3745-21-08(B) and the fuel sulfur content requirements of 40 CFR Part 60, Subpart GG.
OAC rule 3745-17-07(A)(1)	All Egress Points - Visible PE shall not exceed 20% opacity as a 6-minute average, except as provided by rule.
OAC rule 3745-17-11(B)(4)	The PE rate from the turbine shall not exceed 0.040 pound per million Btu of actual heat input; see section A.I.2.d.
OAC rule 3745-18-06(F)	SO_2 emissions from the turbine shall not exceed 0.5 lb/mmBtu of actual heat input; see section A.I.2.d.
OAC rule 3745-21-08(B)	See section A.I.2.e.

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40 CFR Part 60, Subpart GG	NO_X emissions from the turbine shall not exceed 190.0 parts per million, by volume (ppmv), at 15% oxygen, on a dry basis; see section A.I.2.d. The sulfur content of natural gas burned in the turbine shall not exceed 0.8 percent by weight; see section A.I.2.d.
40 CFR Part 63, Subpart YYYY	See section A.VI.3.
OAC rule 3745-31-05(C) - federally enforceable restrictions to avoid PSD requirements.	All Egress Points - The total annual emissions of NO_X and CO from emissions units B013 through B017 shall not exceed 212.91 tons and 221.17 tons, respectively. These annual NO_x and CO emissions limitations shall be achieved by restricting the maximum quantity of natural gas burned to a cumulative total volume of 4,064 million cubic feet based on a rolling 12-month summation.

2. Additional Terms and Conditions

2.a The combustion turbine shall be equipped with a dry, low NO_X emissions combustion system, a low NO_X steam injection system or an equivalent, alternate NO_X emissions control technology.

2.b The allowable rate of 7.03 lbs/hour for NO_X emissions is based on manufacturer's performance guarantees and is established to reflect the potential to emit for this emissions unit.

2.c The allowable rates of 8.57 lbs/hour for CO emissions and 0.46 lbs/hour OC emissions are based on manufacturer's performance guarantees and are established to reflect the potential to emit for this emissions unit.

2.d The emissions limitation(s) specified by this rule is less stringent than the emissions limitation(s) established pursuant to OAC rule 3745-31-05(A)(3).

2.e The permittee shall satisfy the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available technology (BAT) requirements established pursuant to OAC rule 3745-31-05(A)(3) in this permit to install. The design of the emissions unit and the technology associated with the current operating practices satisfy the BAT requirements.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. This rule revision was submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Until the U.S. EPA approves the revision to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

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II. Operational Restrictions

1. The permittee shall burn only natural gas in this emissions unit.

2. Emissions units B013 through B017 have been in operation for more than 12 months and, as such, the permittee has existing records to generate the rolling, 12-month summation of the natural gas fuel usage rate, upon issuance of this permit. The maximum quantity of natural gas fuel which may be burned in emissions units B013 through B017 shall not exceed 4,064 million cubic feet per year based on a rolling 12-month summation of fuel usage.

3. In accordance with 40 CFR Part 60.333(b), the fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

III. Monitoring and/or Recordkeeping Requirements

1. In accordance with 40 CFR 60.334(h), the permittee shall analyze and maintain records of the fuel-bound sulfur content of the natural gas fuel in the following manner:

   a. Monitoring of the sulfur content shall be performed by either the facility, a service contractor retained by the facility, or the fuel supplier.

   b. In accordance with 40 CFR 60.334(h)(1), analysis for total sulfur content of the natural gas fuel shall be conducted using the methods described in 40 CFR 60.335(b)(10)(ii). 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, D4404-01, D5228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see 40 CFR 60.17), which measure the major sulfur compound may be used.

   c. In accordance with 40 CFR 60.334(h)(3), notwithstanding the provisions of 40 CFR 60.334(h)(1), the permittee 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 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the U.S. EPA administrator for 40 CFR Part 60 subpart GG requires such monitoring. The permittee 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 contact 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 20.0 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 40 CFR.

d. In accordance with 40 CFR 60.334(h)(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 been approved, the owner or operator may, without submitting a special petition to the U.S. EPA administrator, continue monitoring on this schedule. During the first six (6) months of operation of this emissions unit, fuel sulfur content monitoring was performed twice per month. The monitoring data showed little variability in the fuel sulfur content, and indicated consistent compliance with 40 CFR 60.333, so that sampling and analysis for fuel sulfur content shall be continue to be conducted once per quarter.

2. For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

3. The permittee shall install, maintain, and operate a properly calibrated natural gas flow rate meter on this emissions unit to allow for accurate determination of the fuel consumption of this combustion turbine.

4. The permittee shall maintain monthly records of the following information:

   a. The volume of natural gas burned in this emissions unit for the calendar month (in millions of cubic feet);

   b. The volume of natural gas burned in emissions units B013 through B017 collectively during the month (in millions of cubic feet);

   c. The volume of natural gas burned for the rolling, 12-month summation period for emissions units B013 through B017 collectively;

   d. The number of hours of operation of this emissions unit for each calendar month;

   e. The collective number of hours of operation of emissions units B013 through B017;

   f. An estimate of the NO_X and CO emissions, in tons/month, from this emissions unit based on the compliance methods listed in sections A.V.1.f. and A.V.1.g., respectively, or upon emissions factors developed from the most recent performance/emissions compliance test data; and

   g. An estimate of the NO_X and CO emissions, in tons/month, from emissions units B013 through B017 collectively.

5. The permittee shall maintain daily records of the following information for this

emissions unit:

a. Except as provided in 40 CFR 60.334 (b) on any day when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, the permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. The permittee shall collect and record the following information each day:

   i. the fuel consumption, in cubic feet on an hourly basis;

   ii. the water or steam injection volume, in lbs/hr

   iii. the hourly ratio of water or steam to fuel;

   iv. if applicable, other operating parameter(s) identified in an on-site parameter monitoring plan, required by 40 CFR 60.334(g); and

   v. the operating times for the capture (collection) system, control device, monitoring equipment, and the associated emissions unit.

b. In accordance with 40 CFR 60.334 (b) for any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous fuel and steam(water) monitoring system described in 40 CFR 60.334(a), the permittee shall install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F–14a or F–14b in appendix F of 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

   i. Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

      (1) on a ppm basis (for NO_X) and a percent O_2 basis for oxygen; or

(2) on a ppm at 15 percent O_2 basis; or

(3) on a ppm basis (for NO_X) and a percent CO_2 basis (for a CO_2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O_2).

ii. As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

iii. For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

(1) For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.334(b)(2), is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under 40 CFR 60.332(a), *i.e.*, percent NO_X by volume, dry basis, corrected to 15 percent O_2 and International Organization for Standardization (ISO) standard conditions (if required as given in 40 CFR 60.335(b)(1)). For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

(2) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(3) If the owner or operator has installed a NO_X CEMS to meet the requirements of 40 CFR Part 75, and is continuing to meet the ongoing requirements of 40 CFR Part 75, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR Part 75,

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subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c).

c. In accordance with 40 CFR 60.334(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 permittee may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of 40 CFR 60.334(b). Also, if the permittee has previously submitted and received U.S. EPA, or Ohio EPA approval of a procedure for monitoring compliance with the applicable NO_X emissions limit under 40 CFR 60.332, that approved procedure may continue to be used.

IV. Reporting Requirements

1. The permittee shall submit annual deviation reports which identify all periods during which the sulfur content of the fuel fired in this emissions unit exceeded 0.8%, by weight. These reports shall be submitted by January 31 of each year.

2. The permittee shall submit deviation (excursion) reports that identify all periods during which the emissions limitations listed above in these terms and conditions were exceeded or the required records were not maintained. Such report shall be sent to the Northeast District Office within 30 days following the end of the calendar month during which the exceedance or deviation occurred.

3. The permittee shall submit deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit. Each report shall be submitted within 30 days after the deviation occurs.

4. The permittee shall submit quarterly deviation (excursion) reports which identify all exceedances of the rolling, 12-month natural gas usage limitation for emissions units B013-B017.

5. Permittee shall submit an annual report which summarizes the monthly and cumulative annual hours of operation of this emissions unit. This report shall be submitted to the Northeast District Office of the Ohio EPA by January 31 of each year for data recorded during the previous calendar year.

6. The permittee shall also submit annual reports which specify the total NO_X emissions and total CO emissions (in tons per year) from this emissions unit for the previous calendar year. These reports shall be submitted by January 31 of each year.

7. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, excess

emissions reports shall be submitted in accordance with 40 CFR 60.334(j). An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water fuel ration needed to demonstrate compliance with the NO_X emissions standard in 40 CFR 60.332, as established during the performance test required in 40 CFR 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

The permittee shall submit quarterly deviation (excursion) reports that identify all periods of time during which the operating parameter(s) does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the emissions unit. The quarterly report shall include the following information:

a. date(s) and time(s) of parameter deviation;

b. average steam or water-to-fuel ratio;

c. average fuel consumption, in cubic feet;

d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury, and humidity in percent); and

e. gas turbine load, in kilowatts.

The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

8. For any period when a low NO_X steam injection system or another similar fluid injection NO_X emissions control technology is employed at the combustion turbine, monitor downtime reports shall be submitted in accordance with 40 CFR 60.334(j). A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

   The permittee shall submit semi-annual deviation (excursion) reports that identify all periods of monitor downtime and shall include the following information:

   a. date(s) and time(s) of monitor downtime(s);

   b. average steam or water-to-fuel ratio, if available;

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c. average fuel consumption, in cubic feet;

d. ambient conditions (temperature in Fahrenheit or Celsius, pressure in inches of mercury and humidity in percent); and

e. gas turbine load, in kilowatts.

The ambient conditions do not need to be reported if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the ISO correction equation under the provisions of 40 CFR 60.335(b)(1) are employed.

9. The permittee shall submit a notification report 30 days prior to any conversion from a low NO_X steam injection emissions control technology to another NO_X emissions control technology.

V. Testing Requirements

1. Compliance with the emission limitation(s) and fuel restriction in Sections A.I. and A.II. of these terms and conditions shall be determined in accordance with the following method(s):

a. Emission Limitation: Visible particulate emissions from the exhaust stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by rule.

Applicable Compliance Method: If required, compliance shall be determined through visible emissions observations performed in accordance with 40 CFR Part 60, Appendix A, Method 9 and the procedures specified in OAC rule 3745-17-03(B)(1).

b. Emission Limitation: The PE rate from this emissions unit shall not exceed 0.43 lbs/hr and 1.88 TPY.

Applicable Compliance Method: Compliance with these emission limitations may be determined by multiplying the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0075 lbs/mmBtu as specified in USEPA reference document AP-42, Fifth Edition, Compilation of Air Pollution Emission Factors, Section 3.1, Table 3.1-2a (4/00) to determine an hourly emissions value. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of the monthly hours of operation as required by section A.III.4. .

If required pursuant to OAC rule 3745-15-04, the permittee shall demonstrate compliance with the particulate emissions limits of this permit by means of physical testing of the effluent from this emissions unit in accordance with testing procedures listed in 40 CFR Part 60, Appendix A, Methods 1-5.

c. Fuel Sulfur Content Limitation: The gaseous fuel burned in this emissions unit shall not contain sulfur in excess of 0.8%, by weight.

Applicable Compliance Method: Compliance with the fuel sulfur content limitation shall be determined in accordance with the procedures specified in 40 CFR 60.334(h)(1) or 40 CFR 60.334(h)(3) as is required in section A.III.1.-A.III.1.d. If the applicable ranges of some compliance methods in the aforementioned rules are not adequate to measure the levels of sulfur in the gaseous fuel, dilution of samples before analysis (with verification of the dilution ratio) may be conducted, with prior approval from the U.S. EPA Administrator.

d. Emissions Limitations: SO_2 emissions from this emissions unit shall not exceed 0.46 lb/hr and 2.01 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined in the following manner:

For the entire emissions unit, multiply the maximum rated heat input capacity of 65.1 mmBtu/hr by an emissions factor of 0.0072 lb/mmBtu, as specified in the application for this permit, to determine an hourly emissions value. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly SO_2 emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

e. Emissions Limitations: OC emissions from this emissions unit shall not exceed 0.46 lbs/hr and 7.49 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined by multiplying the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.0263 lb/mmBtu (per manufacturer's emissions test data supplied by applicant) to determine an hourly emissions value. Compliance with the annual emissions limitation shall be determined by applying the calculated hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

If required, the permittee shall demonstrate compliance with this emissions limitation through emissions tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-4 and 18, 25 or 25A as appropriate.

f. Emissions Limitations: NOx emissions from this emissions unit shall not exceed 7.03 lbs/hr and 30.79 TPY.

Applicable Compliance Method: Compliance with these emissions limitations may be determined by multiplying the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.108 lb/mmBtu as specified by manufacturer's test data for this machine using a low NOx control system to determine an hourly emissions value. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly NO_X emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

g. Emissions Limitations: CO emissions from this emissions unit shall not exceed 8.57 lbs/hr and 37.54 TPY.

Applicable Compliance Method: Compliance with these emission limitations may be determined by multiplying the maximum rated heat input capacity of the emissions unit (65.1 mmBtu/hr at 0^0 F for hourly emissions or 55.65 mmBtu/hr at 55^0 F for annual emissions) by an emissions factor of 0.1316 lb/mmBtu as specified in the manufacturer's guaranteed performance data to determine an hourly emissions value. After the installation of a steam injection or other equivalent NO_X control technology, performance tests shall be conducted to demonstrate compliance with the hourly CO emissions limit. Compliance with the annual emissions limitation shall be determined by applying the measured hourly emissions limit to the summation of monthly hours of operation, as required by section A.III.4.

h. Emissions Limitations: NO_x emissions shall not exceed 212.91 TPY and CO emissions shall not exceed 221.17 TPY from emissions units B013 through B017

Applicable Compliance Method: Compliance with the annual emissions limitations for B013 through B017 shall be determined by the summation of monthly emissions from emissions units B013 through B017 collectively, as required by section A.III.4.

2. Emissions Testing Requirement :

a. Not later than 30 days prior to the proposed test date(s) required in section A.V.2.b., the permittee shall submit an "Intent to Test" notification to the Ohio EPA Northeast District Office. The "Intent to Test" notification shall describe in detail the proposed test methods and procedures, the emissions unit operating parameters, the time(s) and date(s) of the test(s), and the person(s) who will be conducting the test(s). Failure to submit such notification for review and approval prior to the test(s) may result in the Ohio EPA Northeast District Office's refusal to accept the results of the emission test(s).

b. Within 60 days , but not later than 180 days after startup of this emissions unit after the conversion of a NO_X emissions control technology to another NO_X emissions control technology (per 40 CFR 60.8), the permittee shall conduct, or have conducted, performance testing for this emissions unit in accordance with the following requirements:

i. The emissions testing shall be conducted to demonstrate compliance with the allowable mass emission rates for NO_X SO_2 , and CO.

ii. The following test method(s) shall be employed to demonstrate compliance with the allowable mass emission rate(s):

(1) for NO_X , Method 20 of 40 CFR Part 60, Appendix A, ASTM D6522-00 (incorporated by reference, see 40 CFR 60.17), or Method 7E and either EPA Method 3 or 3A of 40 CFR Part 60, Appendix A to determine NO_X and diluent concentration [as specified in 40 CFR 60.335(a)];

(2) for SO_2, Method 20 or Method 6C of 40 CFR Part 60, Appendix A; and

(3) for CO, Method 10 of 40 CFR Part 60, Appendix A.
Alternative U.S. EPA approved test methods may be used with prior approval from the Ohio EPA.

iii. The 3-run performance NO_X tests shall be conducted while the combustion turbine is operating within $\pm$ 5 percent at 50, 75, 90 and 100% of peak load or at four load points in the normal operating range of the gas turbine, including the minimum point in operating the range and 90-100 percent of peak load or at the highest achievable load point if 90-100 percent of peak load cannot be physically achieved in practice.

iv. A 3-run test for SO_2 emissions shall be conducted while the combustion turbine is at the highest achievable load point.

v. This emissions unit may be tested for CO emissions to establish a CO emissions factor for the combined cycle system. Two 3-run tests for CO emissions shall be conducted while the combustion turbine is operating at or near 50 and 100% of peak load or at or near 2 points including the minimum point in the normal operating range of the gas turbine and the highest achievable load point of the gas turbine.

vi. In accordance with 40 CFR 60.334(g) the steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of 40 CFR 60.334 shall be monitored during the performance test required under 40 CFR 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to 40 CFR Part 75 and that use the low mass emissions methodology in 40 CFR 75.19 or the NO_X emission measurement methodology in appendix E of 40 CFR Part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in 40 CFR 75.19(e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to 40 CFR Part 75.

c. Personnel from the Ohio EPA Northeast District Office shall be permitted to witness the test(s), examine the testing equipment, and acquire data and information necessary to ensure that the operation of the emissions unit and the testing procedures provide a valid characterization of the emissions from the emissions unit and/or the performance of the control equipment.

d. A comprehensive written report on the results of the emissions test(s) shall be signed by the person or persons responsible for the tests and submitted to the Ohio EPA Northeast District Office within 30 days following completion of the test(s). The permittee may request additional time for the submittal of the written report, where warranted, with prior approval from the Ohio EPA Northeast District Office.

e. For any conversion of a NO_X emissions control technology to another NO_X emissions control technology, including dry, low NO_X emissions combustion system, additional emissions testing as specified in sections A.V.2.a. - A.V.2.d. shall be required.

VI. Miscellaneous Requirements

1. This emissions unit was initially installed on January 1, 2001 with a low NO_X combustor burner within the combustion turbine. This third administrative permit modification allows the use of steam injection for NO_X emissions control at the turbine.

2. The fuel-bound nitrogen content will be assumed to be zero as long as natural gas fuel is employed in the turbine. Therefore the permittee is exempt from the nitrogen content monitoring of the fuel specified in 40 CFR 60.334(h)(2).

3. Since this emissions unit was installed prior to January 14, 2003, the turbine is considered an "existing stationary combustion turbine" per 40 CFR 63.6090 and is therefore not subject to the formaldehyde concentration exhaust gas limitation(s) within 40 CFR 63.6100. According to 40 CFR 63.6090(a)(3) turbine engine replacement may be considered a reconstructed stationary combustion turbine if it meets the definition of reconstruction in 40 CFR 63.2 of subpart A and if reconstruction commenced after January 14, 2003.

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B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (B017) - Combined cycle 65.1 mmBtu/hr (4.92 MW) natural gas-fired combustion turbine with NO_X emissions control technology and a heat recovery steam generator no. 1 - Chapter 31 modification of PTI 02-13197 originally issued as PTI 02-3197 on 2/09/00 and administratively modified on 5/03/01, 8/06/02 and on 12/14/06

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
None	None

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

None

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None

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Part III - SPECIAL TERMS AND CONDITIONS FOR SPECIFIC EMISSIONS UNIT(S)

A. State and Federally Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (P001) - Oxidation process: including an aluminum chloride generator (DC-813), an oxidation reactor (DC-827) with a paire filter (FD-822) product capture device, a slurry tank (FA-813), a neutralization tank (FA-601), and a packed column, caustic scrubber (DA-847) with a 16.8 mmBtu/hr natural gas-fired titanium tetrachloride ($TICl_4$) vaporizer (BA-812), a 9.5 mmBtu/hr natural gas-fired oxygen (O_2) preheater (BA-815) and a 2.2 mmBtu/hr natural gas-fired O_2 preheater (BA-816) - Administrative modification of Chapter 31 modification issued as PTI 02-16459 of July 5, 2002, and initially issued as PTI 02-11771, issued February 18, 1998

Applicable Rules & Requirements	Applicable Emissions Limitations/Control Measures

Emissions Unit ID: B017

OAC rule 3745-31-05(A)(3)	Oxidation Process - The particulate emissions (PE) rate shall not exceed 2.62 lbs/hr from the stack egress point of the caustic scrubber (DA-847). The requirements of this rule also include compliance with the requirements of OAC rule 3745-17-07(A). See section A.I.2.a. 16.8 mmBtu/hr Natural Gas-fired $TiCl_4$ Vaporizer (BA-812) - The carbon monoxide (CO) emissions shall not exceed 0.67 lb/hr. The nitrogen oxides (NO_X) emissions shall not exceed 3.86 lbs/hr. The organic compound (OC) emissions shall not exceed 0.18 lb/hr. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-10(B)(1) and 3745-21-08(B). 9.5 mmBtu/hr Natural Gas-fired Oxygen (O_2) Preheater (BA-815) - The CO emissions shall not exceed 0.46 lb/hr. The NO_X emissions shall not exceed 2.13 lbs/hr. The OC emissions shall not exceed 0.10 lb/hr. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-10(B)(1) and 3745-21-08(B). 2.2 mmBtu/hr Natural Gas-fired Oxygen (O_2) Preheater (BA-816) - The CO emissions shall not exceed 0.18 lb/hr. The NO_X emissions shall not exceed 0.21 lb/hr. The OC emissions shall not exceed 0.02 lb/hr. The requirements of this rule also include compliance with the requirements of OAC rules 3745-17-10(B)(1) and 3745-21-08(B). All Egress Points - The PE rate shall not exceed 14.00 tons/year. The CO rate shall not exceed 5.74 tons/year. The NO_X rate shall not exceed 27.18 tons/year. The OC rate shall not exceed 1.33 tons/year.
OAC rule 3745-17-07(A)	All Egress Points - Visible PE shall not exceed 20% opacity as a 6-minute average, except as specified by rule.
OAC rule 3745-17-10(B)(1)	Natural Gas-fired $TiCl_4$ Vaporizer (BA-812) and O_2 Preheaters (BA-815 & BA-816) - The PE rate shall not exceed 0.020 lb/mmBtu of actual heat input.
OAC rule 3745-17-11	Oxidation Process - The emissions limitation specified by this rule is less stringent than the emissions limitation established pursuant to OAC rule 3745-31-05(A)(3).
OAC rule 3745-21-08(B)	Natural Gas-fired $TiCl_4$ Vaporizer (BA-812) and O_2 Preheaters (BA-815 & BA-816) - See section A.I.2.b.

2. Additional Terms and Conditions

2.a Exhaust gases from the paire filter (FD-822) product capture device, serving the oxidation reactor, are routed to the Chlorination Process (P002) instead of the atmosphere. However, during startup or equipment pressure testing, nitrogen or oxygen is used to warm the oxygen preheater(s), BA-815 and BA-816, so that no air contaminant emissions are generated when the paire filter gases are exhausted to the atmosphere.

2.b. The permittee shall satisfy the "best available control techniques and operating practices" required pursuant to OAC rule 3745-21-08(B) by committing to comply with the best available technology (BAT) requirements established pursuant to OAC rule 3745-31-05(A)(3) in this permit to install. The design of the emissions unit and the technology associated with the current operating practices satisfy the BAT requirements.

On November 5, 2002, OAC rule 3745-21-08 was revised to delete paragraph (B); therefore, paragraph (B) is no longer part of the State regulations. This rule revision was submitted to the U.S. EPA as a revision to Ohio's State Implementation Plan (SIP). Until the U.S. EPA approves the revision to OAC rule 3745-21-08, the requirement to satisfy the "best available control techniques and operating practices" still exists as part of the federally-approved SIP for Ohio.

II. Operational Restrictions

1. The pH of the scrubber liquor for the packed column, caustic scrubber (DA-847) shall be continuously maintained at or above 8 at all times, except during calibration, startup and shutdown periods, while the emissions unit is in operation.

2. The packed column, caustic scrubber water flow rate shall be continuously maintained at (DA-847) a minimum value, in gallons per minute, established either during the most recent performance test that demonstrated that the emissions unit was in compliance or by the scrubber manufacturer's written recommendation, while the emissions unit is in operation, except during calibration, startup and shutdown periods.

3. The permittee shall burn only natural gas in the $TiCl_4$ vaporizer (BA-812) burner, and in the O_2 preheater burners (BA-815 and BA-816).

III. Monitoring and/or Recordkeeping Requirements

1. The permittee shall properly operate and maintain equipment to monitor and record the operating parameters of packed column, caustic scrubber DA-847) while the emissions unit is in operation. The monitoring devices shall be calibrated, operated and maintained in accordance with the manufacturer's recommendations, instructions and operating manuals. The permittee shall collect and record the following information each day:

   a. the pH of the scrubber liquor, on a once per 8-hour basis,

b. the scrubber water flow rate, in gallons per minute, on a once per 8-hour basis, and

c. a log or record of operating time for the capture (collection) system, control device, monitoring equipment, and the associated emissions unit.

2. For each day during which the permittee burns a fuel other than natural gas, the permittee shall maintain a record of the type and quantity of fuel burned in this emissions unit.

IV. Reporting Requirements

1. The permittee shall submit quarterly deviation (excursion) reports that identify all periods of time during which the following parameters of the packed column, caustic scrubber (DA-847) liquor parameters did not comply with the levels specified in section A.II.:

a. the pH of the scrubber liquor, and

b. the scrubber water flow rate.

2. The permittee shall submit quarterly deviation (excursion) reports that identify each day when a fuel other than natural gas was burned in this emissions unit.

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V. Testing Requirements

1. Compliance with the emissions limitation(s) in Section A.I.1. of these terms and conditions shall be determined in accordance with the following methods(s):

   a. Emission Limitation: 20% opacity of visible particulate emissions.

   Applicable Compliance Method: Compliance shall be determined based upon OAC rule 3745-17-03(B)(1).

   b. Emission Limitation: 2.62 lbs/hr PE from the caustic scrubber (DA-827) stack egress.

   Applicable Compliance Method(s): To determine the worst case emissions rate, the following equation may be used:

   E_DA-847 (PE) = Conc_PE x Q x 1 lb PE/7,000 grains PE
   x [528/(460 + T) x (1 - H2O)] x 60 min/hr.

   where:
   E_DA-847 (PE) = PE rate from the caustic scrubber, which is 0.245 lb PE/hr.

   Conc_PE = maximum PE concentration in scrubber exhaust, which is 0.03 grain PE/dscf, per engineering estimates noted in the application for PTI 02-22027.

   Q = scrubber exhaust flow rate, which is approximately 1,270 acfm as noted in the application for PTI 02-22027.

   T = actual temperature of scrubber exhaust, which is approximately 68 degrees Fahrenheit.

   H_20 = moisture content of scrubber exhaust, which is approximately 0.25.

   If required, the permittee shall demonstrate compliance with this emission limitation through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-5.

   c. Emission Limitations: 0.020 lb PE/mmBtu from each egress for the $TiCl_4$ vaporizer (BA-812), the O_2 preheater (BA-815), and the O_2 preheater (BA-816).

   Applicable Compliance Method(s): To determine the worst case emissions rate, the following equation may be used:

E(PE) = EF/HC

where:
E_BA812(PE) = the PE rate from the $TiCl_4$ vaporizer (BA-812), in pounds PE per million Btu of maximum heat input.

E_BA815(PE) = the PE rate from the O_2 preheater (BA-815), in pounds PE per million Btu of maximum heat input.

E_BA816(PE) = the PE rate from the O_2 preheater (BA-816), in pounds PE per million Btu of maximum heat input.

EF = the emission factor for the PE rate, 7.6 pounds of particulate emissions per million cubic feet of natural gas employed, specified in AP-42, Table 1.4-2, Chapter 1.4 (7/98).

HC = maximum heat content of natural gas, which is 1,029 Btu per cubic foot as specified in the application for PTI 02-22027.

If required, the permittee shall demonstrate compliance with these emission limitations through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1-5.

d. Emission Limitation: 14.00 TPY PE from all egress points.

Applicable Compliance Method: To determine the maximum, annual rate, the following equation may be used:

PE_TOTAL = [E_DA-847 + (E_BA812(PE) x mmBtu_BA812/hr)
+ (E_BA815(PE) x mmBtu_BA815/hr) + (E_BA816(PE) x mmBtu_BA816/hr)]
x HRS/YR x 1 ton/2000 lbs.

where:
PE_TOTAL = the total PE rate from all egress points, in tons/year.

mmBtu_BA812/hr = the maximum rated heat input capacity of the $TiCl_4$ vaporizer (BA-812), 16.8 mmBtu/hr.

mmBtu_BA815/hr = the maximum rated heat input capacity of the O_2 preheater

(BA-815), 9.5 mmBtu/hr.

mmBtu_BA816/hr = the maximum rated heat input capacity of the O_2 preheater (BA-816), 2.2 mmBtu/hr.

HRS/YR = the actual hours of operation per year, which is the sum of the daily operating hours, as specified in the record keeping requirements of section A.III.2, for the calendar year.

e. Emission Limitations: 0.67 lb CO/hr from the $TiCl_4$ vaporizer (BA-812) egress, 0.46 lb CO/hr from the O_2 preheater (BA-815) egress, and 0.18 lb CO/hr from the O_2 preheater (BA-816) egress.

3.86 lbs NO_X/hr from the $TiCl_4$ vaporizer (BA-812) egress, 2.13 lbs NO_X/hr from the O_2 preheater (BA-815) egress, and 0.21 lb NO_X/hr from the O_2 preheater (BA-816) egress.

0.18 lb OC/hr from the $TiCl_4$ vaporizer (BA-812) egress, 0.10 lb OC/hr from the O_2 preheater (BA-815) egress, and 0.02 lb OC/hr from the O_2 preheater (BA-816) egress.

Applicable Compliance Method(s): To determine the worst case emissions rate, the following equation may be used:

E(lbs/hr) = EF x mmBtu/hr x cf/1029 Btu.

where:
E(lbs/hr) = the rate of CO, NO_X or OC emissions, in pounds/hour.

EF_BA812(CO) = the CO emissions factor for BA-812, 41.16 pounds of CO emissions per million cubic feet of natural gas employed, derived from manufacturer data, in the application for PTI 02-22027.

EF_BA815(CO) = the CO emissions factor for BA-815, 49.7 pounds of CO emissions per million cubic feet of natural gas employed, derived from manufacturer data, in the application for PTI 02-22027.

EF_BA816(CO) = the CO emissions factor for BA-816, 84 pounds of CO emissions per million cubic feet of natural gas employed for small, uncontrolled, natural gas-fired boilers, specified in AP-42, Table 1.4-1, Chapter 1.4 (7/98).

EF_BA812(NO_X) = the NO_X emissions factor for BA-812, 236.67 pounds of NO_X emissions per million cubic feet of natural gas employed, derived from manufacturer data, in the application for PTI 02-22027.

EF_BA815(NO_X) = the NO_X emissions factor for BA-815, 230.50 pounds of NO_X

emissions per million cubic feet of natural gas employed, derived from manufacturer data, in the application for PTI 02-22027.

EF_BA816(NO_X) = the NO_X emissions factor for BA-816, 100 pounds of NO_X emissions per million cubic feet of natural gas employed for small, uncontrolled, natural gas-fired boilers, specified in AP-42, Table 1.4-1, Chapter 1.4 (7/98).

EF_BA812(OC) = EF_BA815(OC) = EF_BA816(CO) = the OC emissions factor, 11 pounds of OC emissions per million cubic feet of natural gas employed for small, uncontrolled, natural gas-fired boilers, specified in AP-42, Table 1.4-2, Chapter 1.4 (7/98).

If required, the permittee shall demonstrate compliance with these emission limitations through emission tests performed in accordance with U.S. EPA Methods 1-4 and 10 for CO emissions, U.S. EPA Methods 1-4 and 7E for NO_X emissions, and U.S. EPA Methods 1-4 and 18, 25 or 25A, as appropriate for OC emissions as found in 40 CFR Part 60, Appendix A. Equivalent, alternative methods (as approved by Ohio EPA) may be performed.

f. Emission Limitations: 5.74 TPY CO, 27.18 TPY NO_X and 1.33 TPY OC emissions from all egress points.

Applicable Compliance Method: To determine the annual rate, the following equation may be used:

E(TPY) = (E_BA812 + E_BA815 + E_BA816) x HRS/YR x 1 ton/2,000 lbs.

where:
E(TPY) = the rate of CO, NO_X or OC emissions, in tons/year.

E_BA812 = the CO, NO_X or OC emissions rate from the $TiCl_4$ vaporizer (BA-812), in pound(s) per hour, as specified in section A.V.1.e.

E_BA815 = the CO, NO_X or OC emissions rate from the O_2 preheater (BA-815), in pound(s) per hour, as specified in section A.V.1.e.

E_BA816 = the CO, NO_X or OC emissions rate from the O_2 preheater (BA-816), in pound(s) per hour, as specified in section A.V.1.e.

VI. Miscellaneous Requirements

Emissions Unit ID: B017

None

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B. State Only Enforceable Section

I. Applicable Emissions Limitations and/or Control Requirements

1. The specific operations(s), property, and/or equipment which constitute this emissions unit are listed in the following table along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures. Emissions from this unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

Operations, Property, and/or Equipment - (P001) - Oxidation process: including an aluminum chloride generator (DC-813), an oxidation reactor (DC-827) with a paire filter (FD-822) product capture device, a slurry tank (FA-813), a neutralization tank (FA-601), and a packed column, caustic scrubber (DA-847) with a 16.8 mmBtu/hr natural gas-fired titanium tetrachloride ($TICl_4$) vaporizer (BA-812), a 9.5 mmBtu/hr natural gas-fired oxygen (O_2) preheater (BA-815) and a 2.2 mmBtu/hr natural gas-fired O_2 preheater (BA-816) - Administrative modification of Chapter 31 modification issued as PTI 02-16459 of July 5, 2002, and initially issued as PTI 02-11771, issued February 18, 1998

Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	Compliance with the Air Toxics Policy as specified in section B.III.1.

2. Additional Terms and Conditions

2.a None

II. Operational Restrictions

None

III. Monitoring and/or Recordkeeping Requirements

1. Modeling to demonstrate compliance with the Ohio EPA's "Air Toxic Policy" was not necessary because the increase in emissions due to the modification(s) to the emissions unit was less than the significant level for modeling and was less than 1 ton per year of each toxic pollutant that has a listed Threshold Limit Value (TLV), as documented in the most current version of the American Conference of Governmental Industrial Hygienists' (ACGIH's) handbook entitled "TLVs and BEIs" ("Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices").

IV. Reporting Requirements

None

V. Testing Requirements

None

VI. Miscellaneous Requirements

None