FEB 25 2009

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Houston, Texas 77002

February 19, 2009

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FEB 27 2009

EPA Region 5
Air and Radiation Division
Air Programs Branch (AR-18J)
Air Permits Section
77 West Jackson Boulevard
Chicago, Illinois 60604

Re: Great Lakes Gas Transmission Limited Partnership
Deer River Compressor Station No. 4 (CS4)
Deer River, Minnesota
Federal Permit to Operate No. V-ll-R50002-04-01
Part 71 Permit Renewal

Dear Sir or Madam:

This package is a submission for a Title V Part 71 permit renewal for the Deer River Compressor Station No. 4, Permit No. V-LL-R50002-04-01. Station No. 4 is located near Deer River, Itasca County, Minnesota. Station No. 4 is also located within the external boundaries of the Leech Lake Band of Ojibwe Reservation.

We are requesting the removal of the sulfur monitoring requirements in the current permit. Current tariff sheet for Station No. 4 limits natural gas to no more than 20 grains sulfur per 100 cubic feet of gas (Appendix D in application). Under 40 CFR 60.334(h)(3)(i), Station No. 4 is in compliance with the fuel sulfur limitation of 40 CFR 60.333(b), which assures compliance with 40 CFR 60.333(a).

Please contact Juan J. Rios at (832) 320-5365 or via e-mail at juan_rios@transcanada.com with any questions. Thank you very much for your assistance.

Sincerely,

Juan J. Rios

Juan J. Rios
Environmental Scientist
TransCanada Pipelines

40 CFR Part 71 Federal Operating Permit Renewal Application

Deer River Compressor Station No. 4 (CS4)
Deer River, Minnesota

Owned and Operated By:
Great Lakes Gas Transmission Limited Partnership
P.O. Box 2446
Houston, Texas 77252-2446

February, 2009

URS Job No. 19228677

Prepared by:
URS Corporation
7389 Florida Blvd
Baton Rouge, LA 70806

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List of Abbreviations

AP-42	Compilation of Air Pollutant Emission Factors (U.S. EPA)
AQD	Air Quality Division
BACT	Best Available Control Technology
Btu	British thermal units
Btu/HP-hr	Btu per horsepower hour
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CS4	Compressor Station No. 4
EF	emission factor
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIRE	Factor Information Retrieval System
GE	General Electric
HAP	Hazardous Air Pollutant
HP	horsepower
hr	hour
lb	pound
lb/MMBtu	pounds per million Btu
lb/MMSCF	pounds per million standard cubic feet
MMBtu/hr	million Btu per hour
MMBtu/yr	million Btu per year
MMSCF/yr	million standard cubic feet per year
MPCA	Minnesota Pollution Control Agency
Minn.	Minnesota
mo	month
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
No.	number
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
PM	particulate matter
PM10	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 microns
ppmv	parts per million volume

PSD	Prevention of Significant Deterioration of Air Quality
PTE	potential to emit
SCC	Source Classification Code
SCF	standard cubic feet at standard conditions
SCFH	standard cubic feet per hour at standard conditions
SIC	Standard Industrial Classification
SO2	Sulfur dioxide
TPY	tons per year
μ/m^3	micrograms per cubic meter
USC	United States Code
VOC	volatile organic compound
yr	year

40 CFR Part 71 Federal Operating Permit Renewal Application
Deer River Compressor Station No. 4 (CS4)
Deer River, Minnesota

Great Lakes Gas Transmission Limited Partnership
P.O. Box 2446
Houston, Texas 77252-2446

1.0 INTRODUCTION

1.1 GREAT LAKES GAS TRANSMISSION

Great Lakes Gas Transmission Company, as operator and agent for Great Lakes Gas Transmission Limited Partnership (Great Lakes), operates nearly 2,000 miles of large-diameter underground pipeline, which transports natural gas for delivery to customers in the midwestern and northeastern United States and eastern Canada. Great Lakes also transports gas to and from storage fields located near its pipeline in Michigan. The Great Lakes pipeline system starts at an interconnection with TransCanada Pipelines Limited (TransCanada) near the Manitoba-Minnesota border and traverses northern Minnesota, northern Wisconsin, and the upper and lower peninsulas of Michigan. The Great Lakes pipeline system then reconnects with the TransCanada system near St. Clair, Michigan. A Great Lakes pipeline in the Upper Peninsula of Michigan interconnects with TransCanada facilities at Sault Ste. Marie. The pipeline's 14 compressor stations, placed approximately 75 miles apart, operate to keep natural gas moving through the system. Great Lakes has its headquarters in Troy, Michigan. The Great Lakes pipeline system, and other interstate natural gas transmission pipelines, makes up the long-distance link between natural gas production fields, local distribution companies, and end users.

1.2 DEER RIVER COMPRESSOR STATION NO. 4 (CS4)

Great Lakes operates a natural gas pipeline compressor station (SIC Code 4922, NAICS Code 486210) located approximately 2 miles west of the city of Deer River, Itasca County, Minnesota. The station is located on privately owned fee land within the external boundaries of the Leech Lake Band of Ojibwe Reservation. The primary function of this facility, Deer

River Compressor Station No. 4 (CS4), is to provide motive force for natural gas flowing through the pipeline. The facility operates two stationary natural gas-fired turbines, which in turn drive two natural gas compressors. The pipeline system normally operates continuously, 24 hours per day, 365 days per year.

1.2.1 Purpose of Application

This application is being submitted in accordance with the requirements set forth in Title 40, Part 71, of the Code of Federal Regulations (40 CFR 71) to assure compliance by the source, CS4, with all applicable requirements of Title V of the Clean Air Act (CAA, 42 USC 7401, et seq.).

1.2.2 Organization of Application

This document and the completed U.S.EPA Part 71 Federal Operating Permit Application forms attached in Appendix A comprise the application for the Title V Air Permit renewal. This document is provided to support the information contained in the application forms. Section 2.0 describes the facility, its location, the various emission units at the facility, and the operating methods and procedures practiced at CS4. Sections 3.0 and 4.0 detail the potential and actual emissions from the various emission units at the facility. Finally, Section 5.0 comprises a review of the applicable Federal regulations. Support materials for calculations and compliance determinations are provided in the attached appendices. Page ii, in the front of the document, lists the appendices and their content.

2.0 CS4 FACILITY DESCRIPTION

2.1 FACILITY SITE

Located within the SE ¼ of the NW ¼ of Section 33, Township 145 North, Range 25 West, the CS4 facility is approximately 2 miles west of the city of Deer River, Itasca County, Minnesota. Appendix B contains a Site Location Map.

Three buildings house the emission sources on the site: two compressor buildings and one warehouse building. A Plot Plan and a Stack Location Map for CS4 are included in Appendix B. Each compressor building houses one stationary natural gas-fired turbine/compressor unit. The warehouse building houses a natural gas-fired standby electrical generator. In addition, a service building houses a natural gas-fired boiler and also provides office space, a facility operations computer control and a lunch room. Two full-time staff are employed at the facility and visitors to the station are infrequent.

The facility property is predominately undeveloped and grass-covered. In the middle of the facility property, asphalt-paved driveways and parking areas surround the facility buildings. The entrance to the facility from the access road is located on the east side of the property. The access road extends approximately 0.3 miles south of U.S. Highway 2.

2.2 AREA CLASSIFICATION

The Deer River area is considered an attainment area for all criteria pollutants (40 CFR 50). The facility property, which occupies an area of approximately 20 acres and is owned by Great Lakes, is bordered on the west, north, and south by undeveloped grass-covered and wooded land, and on the east by the access road. CS4 is located on privately-owned fee land within the external boundaries of the Leech Lake Band of Ojibwe Reservation. There are no Mandatory Federal Class I areas within 100 kilometers of CS4.

2.3 PROCESS DESCRIPTION

2.3.1 Current Operations

The facility operates to transport natural gas through a dual 36-inch pipeline system. Two stationary natural gas-fired turbine-driven compressors are used to increase the pressure of the natural gas in the transmission pipeline (see Appendix C for process flow diagrams).

Each compressor building at CS4 houses a three-component stationary natural gas-fired turbine system utilized for compressing the natural gas, which include a gas generator, a power turbine, and a gas compressor (see Figure 2.3.1.).

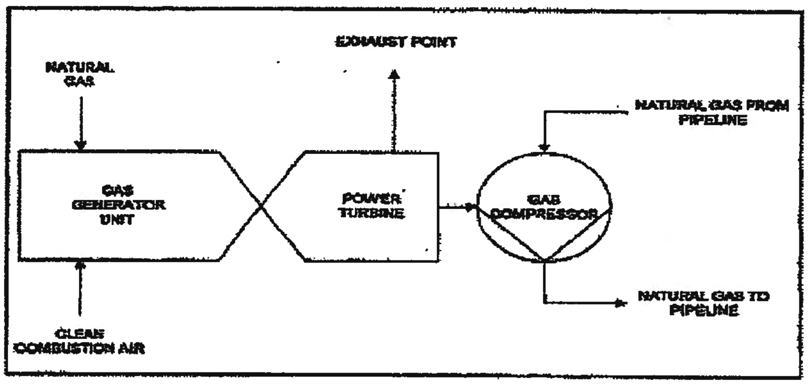

Figure 2.3.1 Turbine/Compressor Process Diagram

The gas generator/power turbine system is considered a simple-cycle system with residual gas energy exhausted into the atmosphere. The gas generator is the component that generates criteria and hazardous air pollutant emissions by means of the combustion of pipeline-quality natural gas (Appendix D, Federal Energy Regulatory Commission (FERC) Gas Tariff, General Terms and Conditions, contains pipeline-quality gas standards). The gas generator, an aircraft-derivative turbine designed to burn natural gas, consists of a clean combustion-air compression section and a natural gas combustor section. The gas generator produces thermodynamic energy or gas horsepower. The gas horsepower, which represents maximum ambient rating for the gas generator unit, is the figure used when calculating the potential to emit (PTE) for the system.

The gas generator is coupled to the power turbine by a transition duct. Gas generator combustion products expand through one or more turbine stages. The power turbine converts the thermodynamic or gas energy from the gas generator to mechanical or rotative energy. The rotative power produced by the power turbine is mechanically coupled to a separate unit, the gas compressor, which pressurizes natural gas to move it through the pipeline system. This rotative power may also be referred to as shaft or brake horsepower.

2.3.2 Natural Gas-Fired Turbine Routine Maintenance and Repair

As a federally regulated public utility, Great Lakes follows a strict preventive maintenance program for its turbines and auxiliary equipment to provide an uninterrupted flow of natural gas through its transmission pipeline system in compliance with its FERC-issued Certificates of Public Convenience and Necessity, granted pursuant to the federal Natural Gas Act, (15 USC 717, *et seq.*). Because Great Lakes is a public utility providing essential natural gas transportation services to large portions of the United States and Canada, it cannot accept periods of downtime that would interrupt this flow. Great Lakes' routine equipment maintenance and repair program is designed to facilitate uninterrupted delivery of natural gas and includes visual inspections, physical examinations, cleaning of combustion areas, and other routine maintenance activities. The program provides for the "change-out" of the gas generator component of a turbine/compressor unit when lengthy repairs or servicing are needed so that the pipeline system remains in full operation.

Routine repair of a gas generator consists of removing it from service and exchanging it for a like-kind gas generator (change-out). The spare gas generator brought in is one of several that are maintained at Great Lakes' off-site warehouses for this purpose. The defective gas generator is either repaired on site, if the repairs are minor, or shipped to a factory-authorized repair facility. When repairs are completed, the gas generator is returned to one of the off-site warehouses for a future change-out within the Great Lakes system. The gas generator that was exchanged for the defective unit remains in service until there is a need to remove it for repairs or an overhaul.

2.3.3 Proposed Modifications

There are no process or equipment modifications proposed under this permit application.

2.4 DESCRIPTION OF INSIGNIFICANT ACTIVITIES

Regulations contained in 40 CFR Part 71 – Federal Operating Permit Program, Subpart A – Operating Permits list information required to be included in an application. A list of insignificant activities and emission limits that need not be included in permit applications can be found in 40 CFR 71.5(c)(11). There are certain small emission sources at CS4 that do not fall into those listed in the regulation. We request that the following small emissions sources at CS4 be considered for inclusion into the permit as insignificant activities.

- CS4 utilizes three natural gas-fired space heaters. The warehouse houses three Reznor natural gas-fired space heaters.
- CS4 operates one diesel storage tank with dispensing operation. The tank is approximately 400 gallons capacity, and is located in the parking lot west of the office/service building.
- Approximately 20 hours per year of arc welding is performed on-site. Arc and oxy-acetylene welding are used to repair equipment and fabricate parts.
- A stationary natural gas-fired boiler with a rated heat input of 5.2 MMBtu/hr, Honda 2.8 HP gasoline-fired generator, and Honda 3.5 HP gasoline-fired water pump.
- CS4 uses less than 30 gallons per year of VOC-containing parts-cleaning fluid in its parts-cleaning bin.
- CS4 has a small abrasive cleaning operation located in a hood with all emissions filtered and vented inside the building.

2.5 DESCRIPTION OF EMISSION UNITS

There are three emission units at the facility. They consist of two stationary natural gas-fired turbines and one natural gas-fired standby electrical generator. Emission unit numbers, stack/vent numbers, and emission unit descriptions are shown in Table 2.5. In addition, a Stack Location Map is located in Appendix B.

None of the emission units at CS4 are equipped with pollution control devices.

Table 2.5
Description of Emission Units

Emission Unit No.	Stack/Vent No.	Description	Manufacturer/ Model	Great Lakes Emission Unit No.	Date Installed
EU001	SV 001	Natural Gas-Fired Turbine	Avon 101G (Rolls Royce)	401	1971
EU002	SV 002	Natural Gas-Fired Turbine	General Electric LM1600	402	1993
EU003	SV 003	Natural Gas-Fired Standby Electrical Generator	Waukesha L36GL (low emissions unit)	N/A	1997

2.5.1 Stationary Natural Gas-Fired Turbines

Two stationary natural gas-fired turbines are located at this facility. The CS4 facility was constructed in 1968-69 and consists of two natural gas-fired turbine units - one Avon (Rolls Royce) 101G and one General Electric LM1600. These are numbered as Units 401 and 402, respectively.

EU001, installed in 1971, is an Avon 101G stationary natural gas-fired turbine. EU001 has a maximum ambient rating of 18,000 horsepower[1] based on ISO standards and a heat input rating of 187.2 million British thermal units per hour (MMBtu/hr). The heat input rating was calculated using 10,400 Btu per horsepower-hour (Btu/HP-hr) as the average heat rate factor (see Section 3.2).

EU002 is a GE LM1600 stationary natural gas-fired turbine installed under MPCA *Air Emission Facility Permit No. 365E-92-OT-1* in 1993 as a replacement unit for two Orenda units originally installed in 1969 and 1970. EU002 has a maximum ambient rating of 23,000 horsepower[2] based on ISO standards and a heat input rating of 184.0 MMBtu/hr (calculated using 8,000 Btu/HP-hr as the heat rate factor; see Section 3.2).

2.5.2 Natural Gas-Fired Standby Electrical Generator

A single natural gas-fired standby electrical generator, located in the warehouse building, provides electrical power for critical operations during temporary electrical power outages and during peak loading. The natural gas-fired standby electrical generator is a Waukesha model L36GL with a rated heat input of 7.2 MMBtu/hr and a horsepower rating of 899 HP. The natural gas-fired standby electrical generator was installed in 1997.

[1] Horsepower is dependent upon ambient temperature and elevation, therefore maximum ambient gas horsepower for the gas generator component is used for emission calculation purposes.

[2] FERC has certificated this natural gas-fired turbine compressor assembly at 15,300 horsepower at NEMA conditions (80°F, 1000 ft elevation). Horsepower is dependent upon ambient temperature and elevation, therefore maximum ambient gas horsepower for the gas generator component is used for emission calculation purposes.

3.0 POTENTIAL TO EMIT (PTE) - CALCULATIONS

3.1 STATIONARY NATURAL GAS-FIRED TURBINES

For the two turbines, calculations of PTE of criteria pollutants and hazardous air pollutants (HAPs), other than NO_X and CO, are based upon emission factors (EFs) published in the latest edition of the U.S. Environmental Protection Agency (EPA) *Compilation of Air Pollutant Emission Factors* (AP-42), Supplement F, July 1993, Section 3.1 Stationary Gas Turbines. Appendix F contains the AP-42 information used in determining emission factors. NO_X and CO emission factors for the stationary natural gas-fired turbines were calculated from emission test results. Appendix J contains emission factors from the most recent EU001 and EU002 Emission Test Report. Criteria pollutant emission factors are reported in pounds per MMBtu (lb/MMBtu) or pounds per million standard cubic feet (lb/MMSCF).

From maximum rated heat inputs in units of MMBtu/hr and fuel inputs in units of standard cubic feet per hour (SCFH), annual fuel usage in units of MMSCF/yr and annual energy usage in units of MMBtu/yr were calculated. A natural gas heating value of 1,020 Btu/SCF was used. The PTE for criteria pollutants and for HAPs were calculated by multiplying EFs by the rated heat input and/or by the fuel input figures. Potential emissions calculations for each emission unit are included on individual PTE calculation spreadsheets that are located in Appendix E.

Because no pollution control devices are installed on the emission units at CS4, all emissions were calculated as uncontrolled emissions.

Using EU001 (Avon 101G) as an example, the following rated heat input was calculated:

18,000 HP x 10,400 Btu/HP-hr x (MMBtu/1,000,000 Btu) = 187.2 MMBtu/hr

3.2 NATURAL GAS-FIRED STANDBY ELECTRICAL GENERATOR

The maximum rated heat input for the natural gas-fired standby electrical generator was calculated by multiplying rated horsepower by an average brake-specific fuel consumption of

8,000 Btu/HP-hr. The standby electrical generator has a rated heat input of 7.2 MMBtu/hr and no backup fuel is used.

Criteria and HAP emissions, excluding NO_X, for the natural gas-fired standby electrical generator are calculated using the emission factors published in AP-42, Section 3.2 Natural Gas-Fired Reciprocating Engines. The NO_X factor was based on the NO_X emission rate listed in the manufacturer's specification (see Appendix K).

3.3 SUMMARY OF POTENTIAL EMISSIONS

Table 3.4
Summary of Potential Emissions (TPY)

Emission Unit No.	Emission Unit Description	NO_X	VOC	SO_2	PM_{10}	CO	Lead	HAP
EU001	Avon 101G Turbine	201.70	1.72	2.79	5.41	485.07	0.00	0.84
EU002	GE LM1600 Turbine	430.36	1.69	2.74	5.32	8.70	0.00	0.83
EU003	Waukesha Generator	18.08	3.72	0.02	0.31	9.99	0.00	2.51
Total PTE Emissions (tpy)		650.14	7.13	5.55	11.05	503.76	0.00	4.18

4.0 ACTUAL EMISSIONS CALCULATIONS

4.1 EXISTING PERMIT EMISSION LIMITATIONS

According to the current Title V Operating Permit, the stationary natural gas-fired turbine EU002 at CS4 is subject to the following NO_X and SO_2, emission limits:

EU002 Permit Limits Under NSPS Subpart GG	
Limit	Regulatory Reference
Emissions shall not exceed 196 ppmv NO_X at 15% oxygen, dry basis	40 CFR 60.332(a)(2)
Fuel burned shall not exceed 0.8 % by weight total sulfur (8,000 ppmw)	40 CFR 60.333(b)

Great Lakes performs fuel sulfur testing according to an EPA-approved custom monitoring plan approved on November 20, 1998. In addition, the sulfur content of pipeline quality natural gas throughout the United States is limited by FERC-driven tariff agreements to no more than 20 grains of total sulfur per 100 cubic feet of gas (see Appendix D). This limit is approximately 640 ppm or 0.064 percent by weight.

Based on the demonstration of the current tariff sheet (see Appendix D) for the compressor station, under 40 CFR 60.334(h)(3)(i) EU002 is in compliance with the fuel sulfur limitation of 40 CFR 60.333(b), which assures compliance with 40 CFR 60.333(a). Great Lakes proposes that the sulfur monitoring requirements, be excluded from the renewed Title V operating permit.

4.2 ACTUAL EMISSIONS CALCULATIONS

4.2.1 Stationary Natural Gas-Fired Turbines

No physical or operational limitations have been imposed upon the stationary natural gas-fired turbines, although a NO_X emission limit based on volume has been set for EU002.

Compliance testing has shown that the EU002 turbine operates well within the NO_X NSPS emission limit of 196 ppmv.

Actual emissions of criteria pollutants and hazardous air pollutants are calculated based on the actual amount of natural gas consumed by each unit in 2007.

To calculate actual NO_X and CO emissions for unit EU001 and EU002, emission factors were calculated for each unit based on the results of the most recent stack test. The emissions factors are listed in Appendix J.

4.2.2 Natural Gas-Fired Standby Electrical Generator

Actual emissions for the standby electrical generator were calculated using the recorded hours of operation in 2007.

4.3 SUMMARY OF ACTUAL EMISSIONS

Table 4.3
Summary of Actual Emissions (tpy)

Emission Unit No.	Emission Unit Description	NO_X	VOC	SO2	PM10	CO	Lead	HAP
EU001	Avon 101G Turbine	95.1	0.8	1.3	2.6	228.6	0.0	0.4
EU002	GE LM1600 Turbine	221.8	0.9	1.4	2.7	4.5	0.0	0.4
EU003	Waukesha Generator	0.2	0.0	0.0	0.0	0.1	0.0	0.0
Total Actual Emissions (tpy)		317.0	1.7	2.7	5.3	233.2	0.0	0.9

5.0 REGULATORY APPLICABILITY SUMMARY

The major federal programs have been summarized in tabular form (Table 5.0) to determine applicability to CS4. Appendix H includes an analysis of the regulations and applicability determinations to support the summary table.

Table 5.0
Regulatory Applicability

Program Description	Regulatory Citation	Unit	Applicability
National Emission Standards for Hazardous Air Pollutants (NESHAPs)	40 CFR 61 40 CFR 63	EU001	No
		EU002	No
		EU003	No
New Source Review (NSR)	40 CFR 52.21	EU001	No
		EU002	No
		EU003	No
National Ambient Air Quality Standards (NAAQS)	1990 CAA as amended §109 and §160-169(b)	EU001	Yes
		EU002	Yes
		EU003	Yes
New Source Performance Standards (NSPS)	40 CFR 60	EU001	No
		EU002	Yes
		EU003	No
Acid Rain Requirements	1990 CAA as amended §401-416 40 CFR 72	EU001	No
		EU002	No
		EU003	No
Stratospheric Ozone Protection Requirements	1990 CAA as amended §601-618 40 CFR 82	CS4	Yes
Risk Management Programs for Chemical Accidental Release Prevention Requirements	1990 CAA as amended §112r 40 CFR 68	EU001	No
		EU002	No
		EU003	No

Appendix A: Part 71 Federal Operating Permit Application Forms

- Form 5900-79: GIS, General Information and Summary
- Form 5900-80: EUD-1, Emissions Unit Description for Fuel Combustion Sources, one each for EU001, EU002, and EU003
- Form 5900-83: IE, Insignificant Emissions
- Form 5900-84: EMISS, Emissions Calculations, one each for EU001, EU002, and EU003
- Form 5900-85: PTE, Potential to Emit Summary
- Form 5900-86: I-COMP, Initial Compliance Plan and Compliance Certification
- Form 5900-02: CTAC, Certification of Truth, Accuracy, and Completeness

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

GENERAL INFORMATION AND SUMMARY (GIS)

A. Mailing Address and Contact Information

Facility name: Great Lakes Gas Transmission/TransCanada - Deer River Compressor Station 4

Mailing address: Street or P.O. Box: 717 Texas St

City: Houston State: TX ZIP: 77002

Contact person: Juan J. Rios Title: Sr. Environmental Scientist

Telephone: (832) 320-5365 Ext. ____

Facsimile: (832) 320-6362

B. Facility Location

Temporary source? ___Yes X No Plant site location: 31641 Great Lakes Road

City: Deer River State: MN County: Itasca EPA Region: 5

Is the facility located within:

Indian lands? X YES ___ NO OCS waters? ___YES X NO

Non-attainment area? ___ YES X NO If yes, for what air pollutants? N/A

Within 50 miles of affected State? __ YES X NO If yes, What State(s)? ____

C. Owner

Name: Great Lakes Gas Transmission Limited Partnership Street/P.O. Box: 5250 Corporate Dr

City: Troy State: MI ZIP: 48098

Telephone (832) 320-5365 Ext ____

D. Operator

Name: Great Lakes Gas Transmission Company Street/P.O. Box: 5250 Corporate Dr

City: Troy State: MI ZIP: 48098

Telephone (832) 320-5365 Ext ____

E. Application Type

Mark only one permit application type and answer the supplementary question appropriate for the type marked.

___Initial Permit X Renewal ___ Significant Mod ___ Minor Permit Mod(MPM)

___ Group Processing, MPM ___ Administrative Amendment

For initial permits, when did operations commence? _____/_____/_____

For permit renewal, what is the expiration date of current permit? 9 / 28 / 2009

F. Applicable Requirement Summary

Mark all types of applicable requirements that apply.

___ SIP ___ FIP/TIP ___PSD ___Non-attainment NSR

___ Minor source NSR X Section 111 ___ Phase I acid rain ___Phase II acid rain

X Stratospheric ozone ___ OCS regulations ___ NESHAP ___ Sec. 112(d) MACT

___ Sec. 112(g) MACT ___ Early reduction of HAP ___ Sec 112(j) MACT ___ RMP [Sec.112(r)]

___ Tank Vessel requirements, sec. 183(f)) ___ Section 129 Standards/Requirement

___ Consumer / comm. products, ' 183(e) ___ NAAQS, increments or visibility (temp. sources)

Has a risk management plan been registered? ___YES ___NO Regulatory agency ___________

Phase II acid rain application submitted? ___YES ___NO If yes, Permitting authority ___________

G. Source-Wide PTE Restrictions and Generic Applicable Requirements

Cite and describe any emissions-limiting requirements and/or facility-wide "generic" applicable requirements.

Not applicable.

H. Process Description

List processes, products, and SIC codes for the facility.

Process	Products	SIC
Natural Gas Transmission	Not applicable	4922

I. Emission Unit Identification

Assign an emissions unit ID and describe each emissions unit at the facility. Control equipment and/or alternative operating scenarios associated with emissions units should by listed on a separate line. Applicants may exclude from this list any insignificant emissions units or activities.

Emissions Unit ID	Description of Unit
001	Natural gas fired turbine Unit 401
002	Natural gas fired turbine Unit 402
003	Standby Electrical Generator

J. Facility Emissions Summary

Enter potential to emit (PTE) for the facility as a whole for each air pollutant listed below. Enter the name of the single HAP emitted in the greatest amount and its PTE. For all pollutants stipulations to major source status may be indicated by entering "major" in the space for PTE. Indicate the total actual emissions for fee purposes for the facility in the space provided. Applications for permit modifications need not include actual emissions information.

NOx: **650.14** tons/yr VOC: **7.13** tons/yr SO2: **5.55** tons/yr

PM-10: **11.05** tons/yr CO: **503.76** tons/yr Lead: **0.00** tons/yr

Total HAP: **4.18** tons/yr

Single HAP emitted in the greatest amount: **formaldehyde** PTE: **2.89** tons/yr

Total of regulated pollutants (for fee calculation), Sec. F, line 5 of form FEE: N/A tons/yr

K. Existing Federally-Enforceable Permits

Permit number(s): V-LL-R50002-04-01 Permit type: Part 71 Permitting authority: EPA-Region 5

Permit number(s) ____________ Permit type ____________ Permitting authority ____________

L. Emission Unit(s) Covered by General Permits

Emission unit(s) subject to general permit: NA

Check one: ___ Application made ___ Coverage granted

General permit identifier ____________ Expiration Date ___/___/___

M. Cross-referenced Information

Does this application cross-reference information? X YES ___ NO (If yes, see instructions)

INSTRUCTIONS FOLLOW

INSTRUCTIONS FOR GIS, GENERAL INFORMATION AND SUMMARY

Use this form to provide general and summary information about the part 71 source (facility or plant) and to indicate the permitting action requested. Submit this form once for each part 71 source. Several sections of this form ask for information you may not know until you complete other part 71 forms.

Section A - Enter the facility's official or legal name. The contact person should be a person familiar with the day-to-day operation of the facility, such as a plant site manager or similar individual.

Section B – If different from the mailing address, include the plant site location.

Sections C and D - If more than one owner or operator, list them on an attachment.

Section E - Mark initial permit issuance if you are applying for the first time. For all types of permit revisions, applicants must provide a brief narrative description of the changes.

Section F - Indicate the broad categories of applicable requirements that apply to the facility or any emissions units. Note that acid rain requirements must be included in part 71 permits the same as other requirements. Also see definition of "applicable requirement" in part 71.

Section G – List emission-limiting requirements that apply to the facility as a whole, such as restrictions on potential to emit or applicable requirements that apply identically to all emission units at a facility.

Section H - List, in descending order of priority, the 4-digit standard industrial classification (SIC) code(s) that best describes your facility in terms of its principal products or processes, and provide a brief narrative description for each classification. For a listing of SIC codes, see the Standard Industrial Classification Manual, 1987 edition, prepared by the Executive Office of the President, Office of Management and Budget, from the Government Printing Office, Washington DC.

Section I - Assign a unique identifier (unit ID) under the "emissions unit ID" column and provide a text description for each significant emissions unit at facility. These IDs will be used in other part 71 forms. A "significant emissions unit" is any unit that is not an insignificant emission unit or activities. Note that unit IDs need only be assigned if they will be referenced in subsequent portions of the application. You may choose any numbering system you wish to assign unit IDs. If a unit ID was previously assigned, use the original ID. If the unit is a new unit, assign a unit ID consistent with the existing units' IDs.

You may group emissions units, activities, or pieces of equipment together and assign a single unique unit ID when they are subject to the same applicable requirement(s) and will have the same monitoring, record keeping, and reporting requirements in the permit.

In addition, assign a unit ID for each alternative operating scenario and each piece of pollution control equipment. When possible, assign these numbers so as to show with which emissions units or processes these scenarios or control devices are associated.

Section J - Show the total emissions for the source in terms of PTE for applicability purposes for each air pollutant listed below and the total actual emissions for fee purposes. Applications for permit revisions should report PTE after the change for the emissions units affected by the change.

Completion of form **PTE** is recommended prior to the entry of PTE information in this section.

"NOx" is an abbreviation for nitrogen oxides,
"VOC" is for volatile organic compounds,
"SO2" is for sulfur dioxide,
"PM10" is for particulate matter with an aerodynamic diameter of 10 micrometers or less,
"CO" is for carbon monoxide, and
"Lead" is for elemental lead regulated by a NAAQS ("compounds of lead" are HAP).

Also note that each individual HAP on the list of HAP in section 112(b) of the Act is a separate regulated air pollutant.

Include fugitive emissions when reporting PTE to the extent that they count toward major source applicability. All fugitive emissions of HAP count toward major source applicability.

Sources may also stipulate to major source status for the pollutants indicated on the form by entering "Major" in the space provided for PTE values.

You may use the value for actual emissions from section F, line 5, of form **FEE**. When totaling actual emissions for fee purposes, include all emissions, including fugitive emissions, regardless of whether they count for applicability purposes.

Section L - If any emissions unit within your facility is applying, has applied, or currently has a general permit, identify the emissions unit ID and name of the unit, consistent with section I of this form.

Section M - Attach copies of any cross-referenced documents that are not publicly available or otherwise available to the permitting authority.

END

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID: 001 Description: Unit 401

SIC Code: (4-digit) 4922 SCC Code: 20300202

B. Emissions Unit Description

Primary use: Natural gas prime mover Temporary Source: ___Yes X No

Manufacturer: Rolls Royce Model No.: Avon 101G

Serial Number: NA Installation Date: 1/1/1971

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other: (describe) ___

Boiler horsepower rating: ___ Boiler steam flow (lb/hr): ___

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input: 88.23* MM BTU/hr Max. Design Heat Input: 187.2 MM BTU/hr

* Based on 2007 actual fuel use averaged over 8760 operating hours. Actual operating hours not known.

C. Fuel Data

Primary fuel type(s): natural gas   Standby fuel type(s): none

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0.8	0.0	1020

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	757.77 MMscf/yr	0.1835 MMscf/hr	1,607.72 MMscf/yr

E. Associated Air Pollution Control Equipment

Emissions unit ID: NA   Device type: ______________________________

Air pollutant(s) Controlled: ____________________   Manufacturer: ____________________

Model No.: ____________________   Serial No.: ____________________

Installation date: _____/_____/______   Control efficiency (%): ____________

Efficiency estimation method: ______________________________

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft): 48.08   Inside stack diameter (ft): 5.8

Stack temp(°F): 839   Design stack flow rate (ACFM): NA

Actual stack flow rate (ACFM): 189,000   Velocity (ft/sec): 119.22

INSTRUCTIONS FOR EUD-1
EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

Use this form is to describe emissions units that combust solid or liquid fuels, such as boilers, steam generators, electric generators and the like.

Section A – The emissions unit ID should be consistent with the one used in section I of form **GIS**. Enter the four-digit SIC code for the unit, which may be different from that used to describe the facility as a whole. Enter the source classification code (SCC), if known or readily available (not mandatory).

Section B - There may be other information that the permitting authority will need to know that is not specifically requested on the forms and that should be included on attachments. Such information would be critical to identifying the emissions unit and its applicable requirements.

Section C - Describe the primary fuel type is that used during the majority of its operating hours. Your fuel supplier should be able to provide the information requested here. If the supplier provides a range of values, use the highest or worst-case value. Identify and describe any associated air pollution control device. If data provided by the vendor, attach documentation (if available); if other basis, indicate how determined (e.g., AP-42).

Section D - Actual fuel usage will be used to calculate actual emissions for purposes of calculating fees. Maximum usage will be used to calculate PTE. If your fuel is a combination of several fuel types, indicate the average percentage of each fuel on an hourly and yearly basis in the appropriate column or on an attachment. The basis of this fuels usage data must be explained on an attachment. For example, actual fuel consumption could be established from purchase records or records of fuel consumption over the preceding calendar year or for sources that have not yet operated for a full year, from estimations of actual usage.

Section E - Identify and describe any associated air pollution control device for the unit described above. For control efficiency, you may need to contact the vendor, if so, attach copies of correspondence from the vendor documenting these values, if available, or indicate how these values were otherwise determined.

Section F - Complete this section only if ambient impact assessment is an applicable requirement or the facility is a temporary source. This is not common.

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID: 002 Description: Unit 402

SIC Code: (4-digit) 4922 SCC Code: 20300202

B. Emissions Unit Description

Primary use: Natural gas prime mover Temporary Source: ___Yes X No

Manufacturer: General Electric Model No.: LM1600

Serial Number: NA Installation Date: 5/1/1993

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other: (describe) ___

Boiler horsepower rating: ___ Boiler steam flow (lb/hr): ___

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input: 94.81* MM BTU/hr Max. Design Heat Input: 184 MM BTU/hr

* Based on 2007 actual fuel use averaged over 8760 operating hours. Actual operating hours not known.

C. Fuel Data

Primary fuel type(s): natural gas Standby fuel type(s): none

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0.8	0.0	1020

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	814.28 MMscf/yr	0.180 MMscf/hr	1,580.24 MMscf/yr

E. Associated Air Pollution Control Equipment

Emissions unit ID: NA Device type: ____________

Air pollutant(s) Controlled: ____________ Manufacturer: ____________

Model No.: ____________ Serial No.: ____________

Installation date: ____/____/____ Control efficiency (%): ____________

Efficiency estimation method: ____________

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft): 40.0 Inside stack diameter (ft): 6.60

Stack temp(^oF): 934.0 Design stack flow rate (ACFM): NA

Actual stack flow rate (ACFM): 249,809 Velocity (ft/sec): 94.67

INSTRUCTIONS FOR EUD-1
EMISSIONS UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES

Use this form is to describe emissions units that combust solid or liquid fuels, such as boilers, steam generators, electric generators and the like.

Section A – The emissions unit ID should be consistent with the one used in section I of form **GIS**. Enter the four-digit SIC code for the unit, which may be different from that used to describe the facility as a whole. Enter the source classification code (SCC), if known or readily available (not mandatory).

Section B - There may be other information that the permitting authority will need to know that is not specifically requested on the forms and that should be included on attachments. Such information would be critical to identifying the emissions unit and its applicable requirements.

Section C - Describe the primary fuel type is that used during the majority of its operating hours. Your fuel supplier should be able to provide the information requested here. If the supplier provides a range of values, use the highest or worst-case value. Identify and describe any associated air pollution control device. If data provided by the vendor, attach documentation (if available); if other basis, indicate how determined (e.g., AP-42).

Section D - Actual fuel usage will be used to calculate actual emissions for purposes of calculating fees. Maximum usage will be used to calculate PTE. If your fuel is a combination of several fuel types, indicate the average percentage of each fuel on an hourly and yearly basis in the appropriate column or on an attachment. The basis of this fuels usage data must be explained on an attachment. For example, actual fuel consumption could be established from purchase records or records of fuel consumption over the preceding calendar year or for sources that have not yet operated for a full year, from estimations of actual usage.

Section E - Identify and describe any associated air pollution control device for the unit described above. For control efficiency, you may need to contact the vendor, if so, attach copies of correspondence from the vendor documenting these values, if available, or indicate how these values were otherwise determined.

Section F - Complete this section only if ambient impact assessment is an applicable requirement or the facility is a temporary source. This is not common.

EPA United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID: 003 Description: Emergency Standby Generator

SIC Code: (4-digit) 4922 SCC Code: 20300201

B. Emissions Unit Description

Primary use: Supplemental Electrical Generator Temporary Source: ___Yes X No

Manufacturer: Waukesha Motor Co. Model No.: L36GL

Serial Number: C-12221/1 Installation Date: 10/8/1997

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other: (describe) ___

Boiler horsepower rating: ___ Boiler steam flow (lb/hr): ___

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input: 7.2 MM BTU/hr Max. Design Heat Input: 7.2 MM BTU/hr

C. Fuel Data ıel ᶠ

Primary fuel type(s): natural gas Standby fuel type(s): none

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0.8	0.0	1020

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	0.671 MMscf/yr	0.007 MMscf/hr	61.77 MMscf/yr

E. Associated Air Pollution Control Equipment

Emissions unit ID: NA Device type: ______

Air pollutant(s) Controlled: ______ Manufacturer: ______

Model No.: ______ Serial No.: ______

Installation date: ____/____/____ Control efficiency (%): ______

Efficiency estimation method: ______

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft): 24.4 Inside stack diameter (ft): 0.67

Stack temp(°F): 800 Design stack flow rate (ACFM): 3,100

Actual stack flow rate (ACFM): 5,743 Velocity (ft/sec): 271.6

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

INSIGNIFICANT EMISSIONS (IE)

List each insignificant activity or emission unit. In the "number" column, indicate the number of units in this category. Descriptions should be brief but unique. Indicate which emissions criterion of part 71 is the basis for the exemption.

Number	Description of Activities or Emissions Units	RAP, except HAP	HAP
3	Space heaters, Reznor, natural gas-fired, each < 0.2 MMBtu/hr.	X	
1	Parts cleaning bin using approximately 10 gallons/year of VOC-containing parts cleaning fluid.	X	
4	Arc welding torches (3) and oxy-acetylene welding (1) of approximately 20 hr/yr.	X	
1	Boiler, natural gas-fired, 5.2 MMBTU/hr capacity.	X	
1	Diesel aboveground storage tank with dispenser, double walled, less than 400 gallon capacity, approximate.	X	
1	Gasoline-powered portable electrical generator, Honda GX100 engine	X	
1	Gasoline powered portable water pump, Honda GX120 engine	X	
1	Residential hot water heater, natural gas, 0.033 MMBtu/hr	X	
1	Abrasive cleaning operation with hood that filters air and exhausts indoors.	X	

INSTRUCTIONS FOR IE
INSIGNIFICANT ACTIVITIES

Use this form only if you have any equipment, emissions units, or emitting activities at your facility that qualify for insignificant treatment due to insignificant emissions levels (defined in the part 71 rule) and you desire such treatment.

Generally identify the source of emissions.

The "number" column is provided to indicate the total number or units or activities grouped together under one description, for example, equipment such as valves and flanges. However, units or activities that are similar should be listed separately in the form when the descriptions differ in a meaningful way, such as when capacities or sizes differ and this information is relevant, for example, to an applicability determination.

Check one of the columns provided to indicate which emission level criteria of part 71 is met for these units or activities that warrant such treatment. The rule provides 2 emission criteria:

- emissions of 2 tons per year or less or any regulated pollutants except HAP (RAP, except HAP) from any emission unit, or
- 1000 pounds per year or less of any HAP from any emission unit.

Note that part 71 does not exempt any insignificant units from major source applicability determinations.

In addition, attach to this form information concerning equipment, activities, or emissions units that are exempted from an otherwise applicable requirement (e.g., grandfathered emissions units. Please cite the basis for the exemption (e.g., State administrative code or Federal regulation).

United States Environmental Protection Agency

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID: 001

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
Emissions for this unit are listed in Appendix A – Table 4				

INSTRUCTIONS FOR EMISS
EMISSION CALCULATIONS

Use this form to quantify emissions for each significant emissions unit identified in section I of form **GIS**. This form will help you organize emissions data needed on forms **PTE** and **FEE**. Do not complete this form for any units or activities listed as insignificant on form **IE**. Sources applying for permit revisions only need complete this form for each emissions unit affected by the change.

Section A - The emissions unit ID should be the same as that used in section I of form **GIS**.

Section B - First, list each "regulated air pollutant" that is subject to an applicable requirement or that is emitted in major amounts (at the unit or facility). Please list each HAP separately.

Second, list any "regulated pollutant (for fee calculation)" emitted that has not already been listed. If you will not be submitting form FEE with your application, you do not need to perform this or the next step. For fee purposes, fugitive emissions count the same as stack emissions. Any HAP that has not been listed up to this point may be simply listed as "HAP." [There is no need to list carbon monoxide, Class I or II substances under title VI, and pollutants regulated solely by section 112(r) for fee purposes.]

Third, calculate actual emissions of "regulated pollutants (for fee calculation). Actual emissions are calculated based on actual operating hours, productions rates, and in-place control equipment, and the types of materials used during the preceding calendar year. If you already have a permit, you should use the compliance methods required by the permit, such as monitoring or source test data, whenever possible; if not possible, you may use other federally recognized procedures.

Most sources will calculate actual emissions for the preceding calendar year. Sources that commenced operation during the preceding calendar year shall estimate emissions for the current calendar year. Certain sources have the option of estimating their actual emissions for the preceding calendar year, instead of calculating them based on actual emissions data, see the instructions for form **FEE** for more on this topic.

Your emission calculations may be based on generally available information rather than new source testing or studies not already required. If you have listed a pollutant but are unable to calculate its actual emissions without conducting new source testing or extensive studies, you may enter "UN" (for "unknown") in the space provided.

You may round to the nearest ton or use greater precision if you believe it will result in a lower fee.

Fourth, calculate PTE for each "regulated air pollutant." For pollutants not specifically regulated at this emission unit, do not calculate PTE in pounds/hour. You may stipulate that the unit alone triggers major source status for this pollutant by entering "MU" in the space provided for annual PTE values. You may stipulate that the unit does not trigger major source status, but that the aggregate facility emissions or another unit triggers major source status by entering "MS" in the space provided for annual PTE values.

Do not calculate PTE values for emissions that are not counted for major source applicability purposes or for emissions listed solely for fee purposes, however, enter "NA" for "not applicable" in the space provided for PTE values for these emissions.

If you are unable to calculate PTE values for air pollutants counted for applicability purposes without conducting new source testing or extensive studies, enter "UN" (for "unknown") in the space provided.

Within applications for permit revisions, PTE should be calculated assuming the proposed change has occurred.

"Potential to emit" is defined as "the maximum capacity of a stationary source to emit any pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by the Administrator."

Enter values for PTE by rounding to the nearest ton in the space for tons/year or to the nearest pound in the space for pounds/hour. If greater precision is needed or desired, do not round these values until you calculate the total on form **PTE**.

Provide the chemical abstract service number (CAS No.), if available.

END

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID: 002

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
Emissions for this unit are listed in Appendix A – Table 5				

INSTRUCTIONS FOR EMISS
EMISSION CALCULATIONS

Use this form to quantify emissions for each significant emissions unit identified in section I of form **GIS**. This form will help you organize emissions data needed on forms **PTE** and **FEE**. Do not complete this form for any units or activities listed as insignificant on form **IE**. Sources applying for permit revisions only need complete this form for each emissions unit affected by the change.

Section A - The emissions unit ID should be the same as that used in section I of form **GIS**.

Section B - First, list each "regulated air pollutant" that is subject to an applicable requirement or that is emitted in major amounts (at the unit or facility). Please list each HAP separately.

Second, list any "regulated pollutant (for fee calculation)" emitted that has not already been listed. If you will not be submitting form FEE with your application, you do not need to perform this or the next step. For fee purposes, fugitive emissions count the same as stack emissions. Any HAP that has not been listed up to this point may be simply listed as "HAP." [There is no need to list carbon monoxide, Class I or II substances under title VI, and pollutants regulated solely by section 112(r) for fee purposes.]

Third, calculate actual emissions of "regulated pollutants (for fee calculation). Actual emissions are calculated based on actual operating hours, productions rates, and in-place control equipment, and the types of materials used during the preceding calendar year. If you already have a permit, you should use the compliance methods required by the permit, such as monitoring or source test data, whenever possible; if not possible, you may use other federally recognized procedures.

Most sources will calculate actual emissions for the preceding calendar year. Sources that commenced operation during the preceding calendar year shall estimate emissions for the current calendar year. Certain sources have the option of estimating their actual emissions for the preceding calendar year, instead of calculating them based on actual emissions data, see the instructions for form **FEE** for more on this topic.

Your emission calculations may be based on generally available information rather than new source testing or studies not already required. If you have listed a pollutant but are unable to calculate its actual emissions without conducting new source testing or extensive studies, you may enter "UN" (for "unknown") in the space provided.

You may round to the nearest ton or use greater precision if you believe it will result in a lower fee.

Fourth, calculate PTE for each "regulated air pollutant." For pollutants not specifically regulated at this emission unit, do not calculate PTE in pounds/hour. You may stipulate that the unit alone triggers major source status for this pollutant by entering "MU" in the space provided for annual PTE values. You may stipulate that the unit does not trigger major source status, but that the aggregate facility emissions or another unit triggers major source status by entering "MS" in the space provided for annual PTE values.

Do not calculate PTE values for emissions that are not counted for major source applicability purposes or for emissions listed solely for fee purposes, however, enter "NA" for "not applicable" in the space provided for PTE values for these emissions.

If you are unable to calculate PTE values for air pollutants counted for applicability purposes without conducting new source testing or extensive studies, enter "UN" (for "unknown") in the space provided.

Within applications for permit revisions, PTE should be calculated assuming the proposed change has occurred.

"Potential to emit" is defined as "the maximum capacity of a stationary source to emit any pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by the Administrator."

Enter values for PTE by rounding to the nearest ton in the space for tons/year or to the nearest pound in the space for pounds/hour. If greater precision is needed or desired, do not round these values until you calculate the total on form **PTE**.

Provide the chemical abstract service number (CAS No.), if available.

END

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID: 003

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
Emissions for this unit are listed in Appendix A – Table 6				

INSTRUCTIONS FOR EMISS
EMISSION CALCULATIONS

Use this form to quantify emissions for each significant emissions unit identified in section I of form **GIS**. This form will help you organize emissions data needed on forms **PTE** and **FEE**. Do not complete this form for any units or activities listed as insignificant on form **IE**. Sources applying for permit revisions only need complete this form for each emissions unit affected by the change.

Section A - The emissions unit ID should be the same as that used in section I of form **GIS**.

Section B - First, list each "regulated air pollutant" that is subject to an applicable requirement or that is emitted in major amounts (at the unit or facility). Please list each HAP separately.

Second, list any "regulated pollutant (for fee calculation)" emitted that has not already been listed. If you will not be submitting form FEE with your application, you do not need to perform this or the next step. For fee purposes, fugitive emissions count the same as stack emissions. Any HAP that has not been listed up to this point may be simply listed as "HAP." [There is no need to list carbon monoxide, Class I or II substances under title VI, and pollutants regulated solely by section 112(r) for fee purposes.]

Third, calculate actual emissions of "regulated pollutants (for fee calculation). Actual emissions are calculated based on actual operating hours, productions rates, and in-place control equipment, and the types of materials used during the preceding calendar year. If you already have a permit, you should use the compliance methods required by the permit, such as monitoring or source test data, whenever possible; if not possible, you may use other federally recognized procedures.

Most sources will calculate actual emissions for the preceding calendar year. Sources that commenced operation during the preceding calendar year shall estimate emissions for the current calendar year. Certain sources have the option of estimating their actual emissions for the preceding calendar year, instead of calculating them based on actual emissions data, see the instructions for form **FEE** for more on this topic.

Your emission calculations may be based on generally available information rather than new source testing or studies not already required. If you have listed a pollutant but are unable to calculate its actual emissions without conducting new source testing or extensive studies, you may enter "UN" (for "unknown") in the space provided.

You may round to the nearest ton or use greater precision if you believe it will result in a lower fee.

Fourth, calculate PTE for each "regulated air pollutant." For pollutants not specifically regulated at this emission unit, do not calculate PTE in pounds/hour. You may stipulate that the unit alone triggers major source status for this pollutant by entering "MU" in the space provided for annual PTE values. You may stipulate that the unit does not trigger major source status, but that the aggregate facility emissions or another unit triggers major source status by entering "MS" in the space provided for annual PTE values.

Do not calculate PTE values for emissions that are not counted for major source applicability purposes or for emissions listed solely for fee purposes, however, enter "NA" for "not applicable" in the space provided for PTE values for these emissions.

If you are unable to calculate PTE values for air pollutants counted for applicability purposes without conducting new source testing or extensive studies, enter "UN" (for "unknown") in the space provided.

Within applications for permit revisions, PTE should be calculated assuming the proposed change has occurred.

"Potential to emit" is defined as "the maximum capacity of a stationary source to emit any pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable by the Administrator."

Enter values for PTE by rounding to the nearest ton in the space for tons/year or to the nearest pound in the space for pounds/hour. If greater precision is needed or desired, do not round these values until you calculate the total on form **PTE**.

Provide the chemical abstract service number (CAS No.), if available.

END

EPA United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

POTENTIAL TO EMIT (PTE)

For each unit with emissions that count towards applicability, list the emissions unit ID and the PTE for the air pollutants listed below and sum them up to show totals for the facility. You may find it helpful to complete form **EMISS** before completing this form. Show other pollutants not listed that are present in major amounts at the facility on attachment in a similar fashion. You may round values to the nearest tenth of a ton. Also report facility totals in section J of form **GIS**.

Emissions Unit ID	Regulated Air Pollutants and Pollutants for which the Source is Major (tons/yr)						
	NO_X	VOC	SO_2	PM_{10}	CO	Lead	HAP
001	201.70	1.72	2.79	5.41	485.07	0.00	0.84
002	430.36	1.69	2.74	5.32	8.70	0.00	0.83
003	18.08	3.72	0.02	0.31	9.99	0.00	2.51
FACILTY TOTALS	650.14	7.13	5.55	11.05	503.76	0.00	4.18

INSTRUCTIONS FOR PTE
POTENTIAL TO EMIT

Calculate the total PTE for each air pollutant at the facility for purposes of determining major source applicability.

On each line (row) in the table provided, enter the emissions unit ID and the quantity of each air pollutant identified on the form. If form **EMISS** was prepared previously, simply copy the emission values (or stipulations to major source status) contained on those forms to this form. You may round to the nearest ton.

Applicants may stipulate to major source status for an air pollutant and, thereby, avoid detailed PTE calculations. If a unit emits in major amounts, enter "MU" in the column for that air pollutant. If the facility is a major source for a pollutant but the emissions unit in question does not trigger major source status, enter "MS" in the space provided. If a listed pollutant is emitted at a unit but PTE cannot be calculated based on readily available information, enter "UN" (for "unknown") in the space provided. If the source is a major source for air pollutants not represented by columns on this form, please provide an attachment stipulating major source status or the calculation of the total for that air pollutant. The column for lead is for elemental lead regulated by a NAAQS, while compounds of lead are HAP.

The total line is provided at the bottom of each column to enter the total facility-wide PTE for applicability purposes (or stipulations to major source status) for each air pollutant reported above. Enter these totals, as well as the total PTE and the name of the HAP emitted in the greatest amount, in section J of form **GIS**.

Only include emissions or emissions units on form **PTE** that count toward major source applicability. Some of the emissions units for which form **EMISS** may have been prepared may not have emissions that count towards major source applicability or may have been included in order to calculate fees. In particular, fugitive emissions are not always included in major source applicability determinations for non-HAP. However, for major source determinations for HAP, all fugitive HAP must be included.

END

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION (I-COMP)

SECTION A - COMPLIANCE STATUS AND COMPLIANCE PLAN

Complete this section for each unique combination of applicable requirements and emissions units at the facility. List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Indicate your compliance status at this time for this requirement and compliance methods and check "YES" or "NO" to the follow-up question.

Emission Unit ID(s): Facility

Applicable Requirement (Describe and Cite):
40 CFR 60 App.A – Visible emissions are not to exceed 20 percent opacity level for more than ten consecutive seconds once operating temperatures have been attained.

Compliance Methods for the Above (Description and Citation):
Testing. Visual test by certified opacity analyst at request of EPA.

Compliance Status:

_X_ In Compliance: Will you continue to comply up to permit issuance? __X__Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): Facility

Applicable Requirement (Description and Citation):
40 CFR 60.14 – Gas turbine repair/replacement: The periodic repair or replacement of gas turbine components including the gas generator for overhaul or repair does not subject the facility to the requirement of subpart GG unless the changes meet the definition of "modification" (40 CFR 60.14) or "reconstruction" (40 CFR 60.15).

Compliance Methods for the Above (Description and Citation):

Compliance Status:

_X_ In Compliance: Will you continue to comply up to permit issuance? __X__Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes _____No

Emission Unit ID(s): 001

Applicable Requirement (Describe and Cite):
40 CFR 60.332-Nitrogen Oxides: Less than or equal to 0.01963 percent oxygen on a dry basis (or 196.3 ppm at 15% oxygen and on a dry basis.

Compliance Methods for the Above (Description and Citation):
Testing. Method 20 (40 CFR 60, App. A) completed after initial startup.

Compliance Status:

_X_ In Compliance: Will you continue to comply up to permit issuance? __X__Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

---

Emission Unit ID(s): 002

Applicable Requirement (Description and Citation):
40 CFR 60.333(b) Sulfur content of natural gas less than or equal to 0.8% by weight.

Compliance Methods for the Above (Description and Citation):
Testing. Compliance is demonstrated by the current tariff sheet.

Compliance Status:

_X_ In Compliance: Will you continue to comply up to permit issuance? __X__Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes _____No

B. SCHEDULE OF COMPLIANCE

Complete this section if you answered "NO" to any of the questions in section A. Also complete this section if required to submit a schedule of compliance by an applicable requirement. Please attach copies of any judicial consent decrees or administrative orders for this requirement.

Unit(s)____________________ Requirement____

Reason for Noncompliance. Briefly explain reason for noncompliance at time of permit issuance or that future-effective requirement will not be met on a timely basis:

Narrative Description of how Source Compliance Will be Achieved. Briefly explain your plan for achieving compliance:

Schedule of Compliance. Provide a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance, including a date for final compliance.

Remedial Measure or Action	Date to be Achieved

C. SCHEDULE FOR SUBMISSION OF PROGRESS REPORTS

Only complete this section if you are required to submit one or more schedules of compliance in section B or if an applicable requirement requires submittal of a progress report. If a schedule of compliance is required, your progress report should start within 6 months of application submittal and subsequently, no less than every six months. One progress report may include information on multiple schedules of compliance.

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal________________

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal________________

D. SCHEDULE FOR SUBMISSION OF COMPLIANCE CERTIFICATIONS

This section must be completed once by every source. Indicate when you would prefer to submit compliance certifications during the term of your permit (at least once per year).

Frequency of submittal: Annually______________ Beginning____/____/____

E. COMPLIANCE WITH ENHANCED MONITORING & COMPLIANCE CERTIFICATION REQUIREMENTS

This section must be completed once by every source. To certify compliance with these, you must be able to certify compliance for every applicable requirement related to monitoring and compliance certification at every unit.

Enhanced Monitoring Requirements:	____ In Compliance	____ Not In Compliance
Compliance Certification Requirements:	____ In Compliance	____ Not In Compliance

INSTRUCTIONS FOR I-COMP
INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION

Section A (Compliance Status and Compliance Plan)

Description of Applicable Requirement: Complete Section A for each unique combination of applicable requirements (emission limitations, standards or other similar requirements of federal rules, SIP, TIP, FIP, or federally-enforceable permits) that apply to particular emissions units. You will likely have to complete this section numerous times to include all requirements at all emission units.

The emissions unit ID(s) should be the ones defined in section I of form GIS. If the requirement, including compliance method, applies in the same way to multiple emission units, you may list multiple units for a particular requirement.

The descriptions here should be detailed to the individual requirement level, rather than the standard level (if a MACT applies to you, describe each requirement of the MACT, rather than just a citation to the MACT as a whole). If the requirement imposes a particular numerical limit or range, include that in your description.

Citations to the requirements should unambiguously identify the requirement to the lowest level necessary.

Compliance Methods: List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Such methods may be required by the applicable requirements or performed for other reasons. List all compliance methods required by applicable requirements, whether you used them to determine compliance or not.

To describe monitoring, indicate the monitoring device, the equipment, process, or pollutant monitored, averaging time, frequency, and a citation or cross-reference to the requirement. To describe recordkeeping, describe the records kept, the frequency of collection, and include a citation or cross-reference to the requirement. Please indicate whether monitoring data, results, or other records kept for compliance purposes may be kept on-site rather than reported. To describe reporting requirements, describe what is reported, when it is reported, and cite or cross-reference the requirement.

The citation or cross-reference here must unambiguously identify the requirement to the lowest level necessary.

Note that Compliance Assurance Monitoring (CAM) under part 64 is also an applicable requirement that may impose compliance methods for title V sources and require the submittal of a CAM plan with this application. Also note that periodic monitoring (which may be monitoring or recordkeeping designed to serve as monitoring) under part 71 may be required in certain limited circumstances: when there is no monitoring required, monitoring is required but there is no frequency specified, or only a one-time test is required. You may propose periodic monitoring in your application, but the permitting authority will make the final decision. If you wish to propose periodic monitoring, please do so in an attachment that clearly identifies the requirements, the units they apply to, and what you propose for periodic monitoring.

Compliance Status: For each requirement and associated compliance methods described above, indicate whether you are in compliance, not in compliance, or it is a future-effective requirement (only check one). This is with respect to your compliance status at the time of application submittal. You should consider all available information or knowledge that you have when evaluating your compliance status, including reference test methods and other compliance requirements that are required directly by a statute, regulation, or permit and Acredible evidence@ (e.g., non-reference test methods and other information Areadily available@ to you and already being utilized by you). For each compliance status indication, you must answer "YES" or "NO" as to your expectations for continuing (or future) compliance. If you answer "NO" to any of these questions, you will have to complete the schedule of compliance section (section B).

Section B (Schedule of Compliance)

Complete this section if you answered ANO@ to any of the questions in section A. Regardless of how you answered the questions in section A, complete this section if required to have a schedule of compliance by an applicable requirement, or if a judicial consent decree or administrative order includes a schedule of compliance.

Identify the applicable requirement using the same information you used in section A. Provide a brief explanation of the reason for noncompliance (either now or in the future). [e.g., "do not have control device required as BACT."] Next, provide a brief description of what the schedule of compliance is trying to achieve. Then in the table provided, include a detailed schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with the applicable requirement. This schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance must be supplemental to, and not sanction noncompliance with, the applicable requirements on which it is based. For each remedial measure, provide the date by which the action will be completed. This schedule or one approved by the permitting authority will be included in the permit.

Lastly, attach a copy of any judicial consent decrees or administrative orders for which you are providing a schedule of compliance.

Section C (Schedule for Submission of Progress Reports)

If you must submit one or more schedules of compliance (specified in section B), or if an applicable requirement requires submittal of a progress report, complete this section. Progress reports describe your progress in meeting the milestone dates for the remedial measures required by the schedule of compliance. Progress reports must be submitted at least every 6 months, but specific applicable requirements may require them more frequently. One progress report may include information on one or more schedules of compliance. Describe the contents of the progress report, including the date that your facility will begin submitting them and the frequency they will be submitted.

Section D (Schedule for Submission of Compliance Certifications)

All applicants must complete this section. Compliance certifications must be submitted at least every year unless the applicable requirement or EPA requires them more frequently. Provide the date when the first compliance certification will be sent.

Section E (Compliance Status for Enhanced Monitoring and Compliance Certification)

All applicants must complete this section. The completion of this section does not satisfy the requirement for the responsible official to submit a certification of truth, accuracy, and completeness (instead this is met by completing form CTAC and submitting it with the other forms you send to EPA).

To certify compliance with "Enhanced Monitoring," you must be in compliance at all emission units with CAM and "Periodic Monitoring" [required by '71.6(a)(3)(i)(B)], if they apply. "Compliance Certification Requirements" include requirements for compliance certification in title V applications and permits, and possibly through applicable requirements (e.g., certain MACT standards). If you have fully completed sections A - E of this form, you will be in compliance with the compliance certification requirement for applications. If you do not have a title V permit at this time, you can assume you are in compliance with the compliance certification requirements for permits and with periodic monitoring requirements. If you indicate you are "not in compliance" with either of these requirements, attach an explanation.

END

EPA United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS (CTAC)

This form must be completed, signed by the "Responsible Official" designated for the facility or emission unit, and sent with each submission of documents (i.e., application forms, updates to applications, reports, or any information required by a part 71 permit).

A. Responsible Official

Name: (Last) Kornaga (First) Anthony (MI) M

Title: Regional Director of Field Operations

Street or P.O. Box: 5250 Corporate Drive

City: Troy State: MI ZIP: 48098

Telephone (248) 205-7465 Ext. ______ Facsimile (____) ____ - ______

B. Certification of Truth, Accuracy and Completeness (to be signed by the responsible official)

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

Name: (signed) Anth M. Kornaga

Name: (typed) Anthony M. Kornaga Date: 2 / 19 / 2009

INSTRUCTIONS FOR CTAC
CERTIFICATION OF TRUTH, ACURACY, and COMPLETENESS

This form is for the responsible official to certify that submitted documents (i.e., permit applications, updates to application, reports, and any other information required to be submitted as a condition of a permit) are true, accurate, and complete.

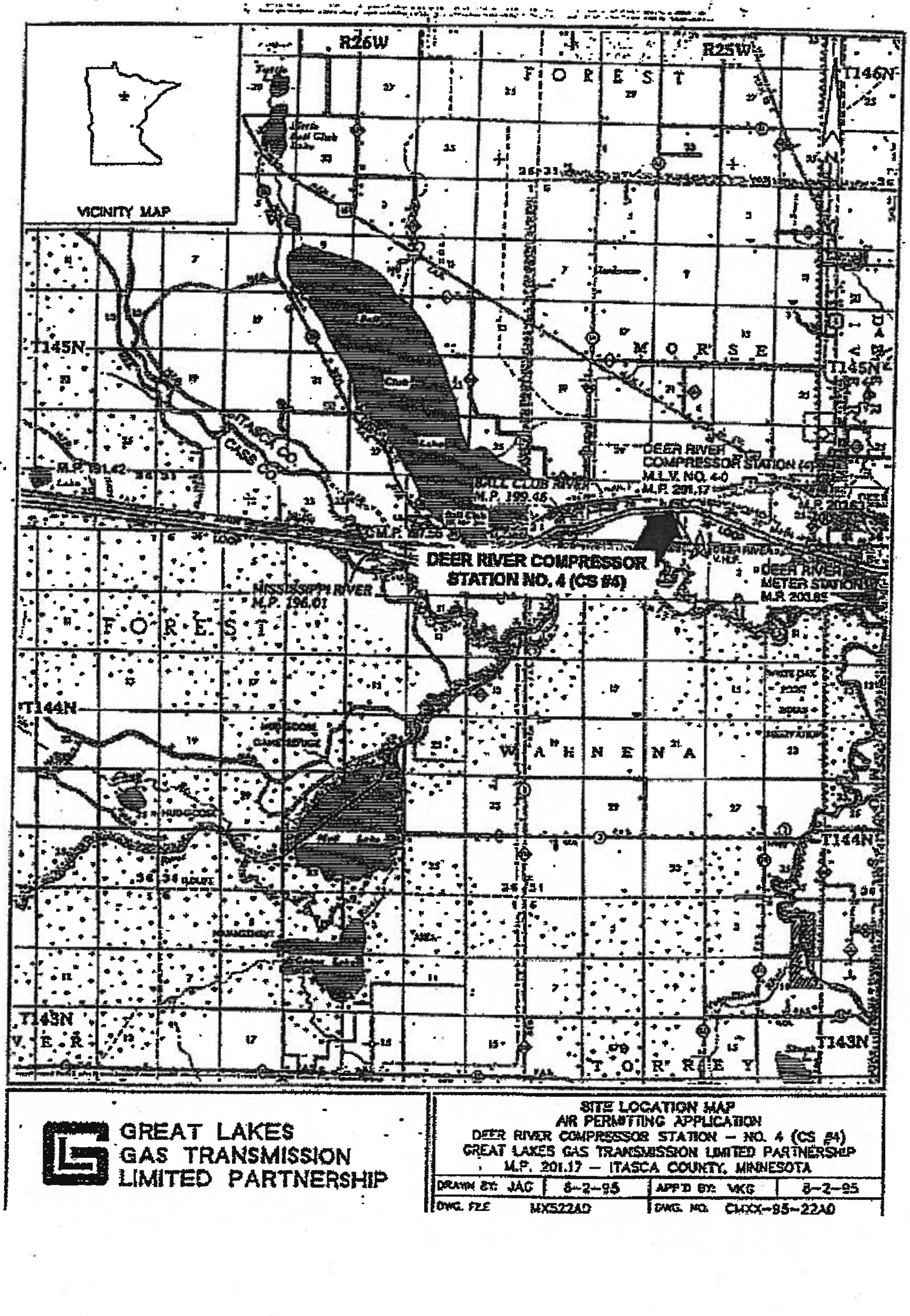
This form should be completed and submitted with each set of documents sent to the permitting authority. It may be used at time of initial application, at each step of a phased application submittal, for application updates, as well as to accompany routine submittals required as a term or condition of a permit.

Section A - Title V permit applications must be signed by a responsible official. The definition of responsible official can be found at ' 70.2.

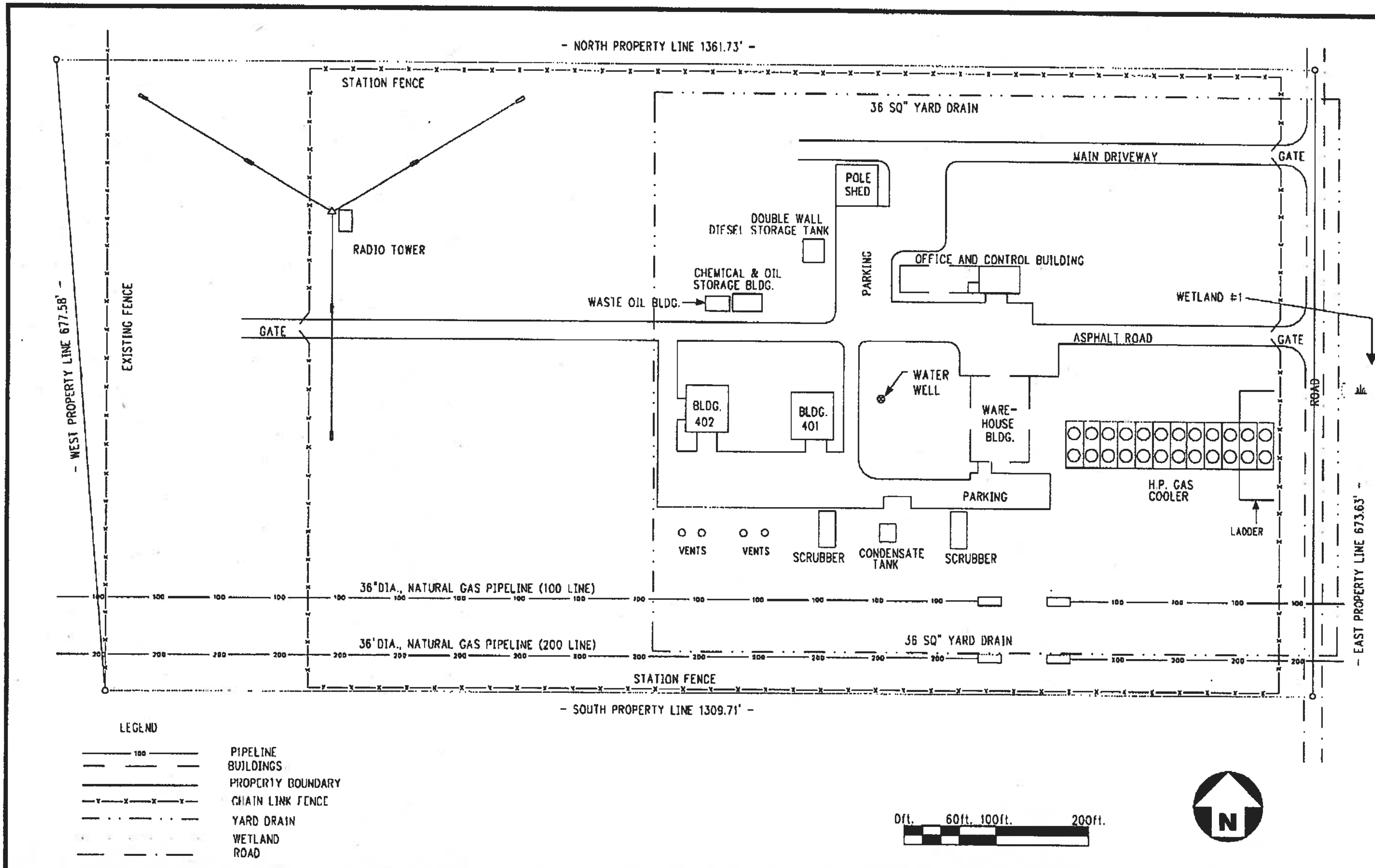
Section B - The responsible official must sign and date the certification of truth, accuracy and completeness. This should be done after all application forms are complete and the responsible official has reviewed the information. Normally this would be the last form completed before the package of forms is mailed to the permitting authority.

Appendix B: Site Map/Plot Plans

- Site Location Map
- Plot Plan
- Stack Location Map



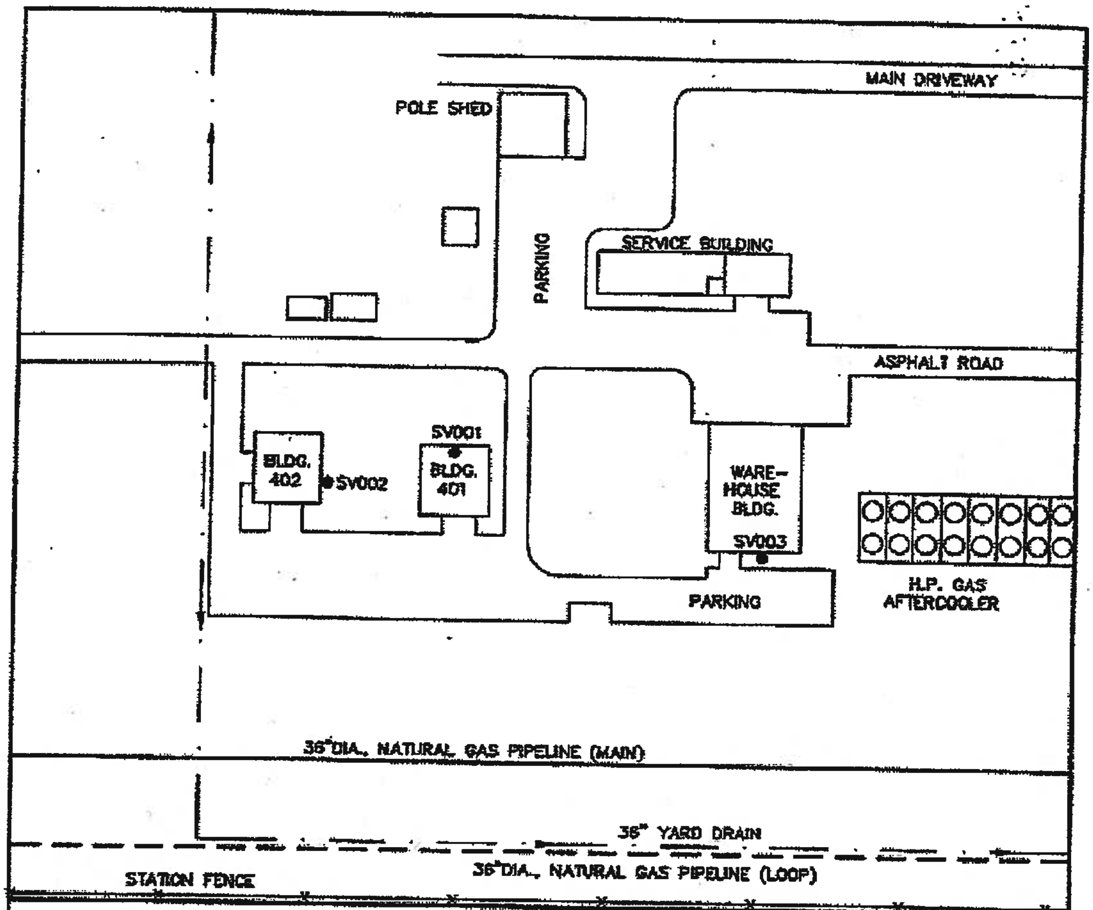
VICINITY MAP
R26W
R25W
T146N
F O R E S T
T145N
M O R S E
T145N
DEER RIVER COMPRESSOR STATION
M.L.V. NO. 4-0
M.P. 201.17
M.P. 191.42
BALL CLUB RIVER
M.P. 199.46
DEER RIVER COMPRESSOR STATION NO. 4 (CS #4)
DEER RIVER METER STATION
M.P. 203.85
MISSISSIPPI RIVER
M.P. 196.01
F O R E S T
T144N
W A H N E N A
T144N
T143N
T O R R E Y
T143N
GREAT LAKES
GAS TRANSMISSION
LIMITED PARTNERSHIP
SITE LOCATION MAP
AIR PERMITTING APPLICATION
DEER RIVER COMPRESSOR STATION – NO. 4 (CS #4)
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
M.P. 201.17 – ITASCA COUNTY, MINNESOTA
DRAWN BY: JAC
8-2-95
APP'D BY: VKG
8-2-95
DWG. FILE MX522AD
DWG. NO. CLXX-95-22AD



Great Lakes Gas Transmission Company

COMPRESSOR STATION NO. 4
ENVIRONMENTAL CONDITIONS - SITE SKETCH
M.P. 201.17, Itasca County
Deer River, Minnesota

DATE	10/28/93
REVISED	03/05/01
FIGURE NO.	104-WS-1000



– PROPERTY LINE 1309.71' –

LEGEND

PROPERTY BOUNDARY
CHAIN LINK FENCE
YARD DRAIN
EMISSION POINT

N

50' 0 100'

SCALE 1"=100'

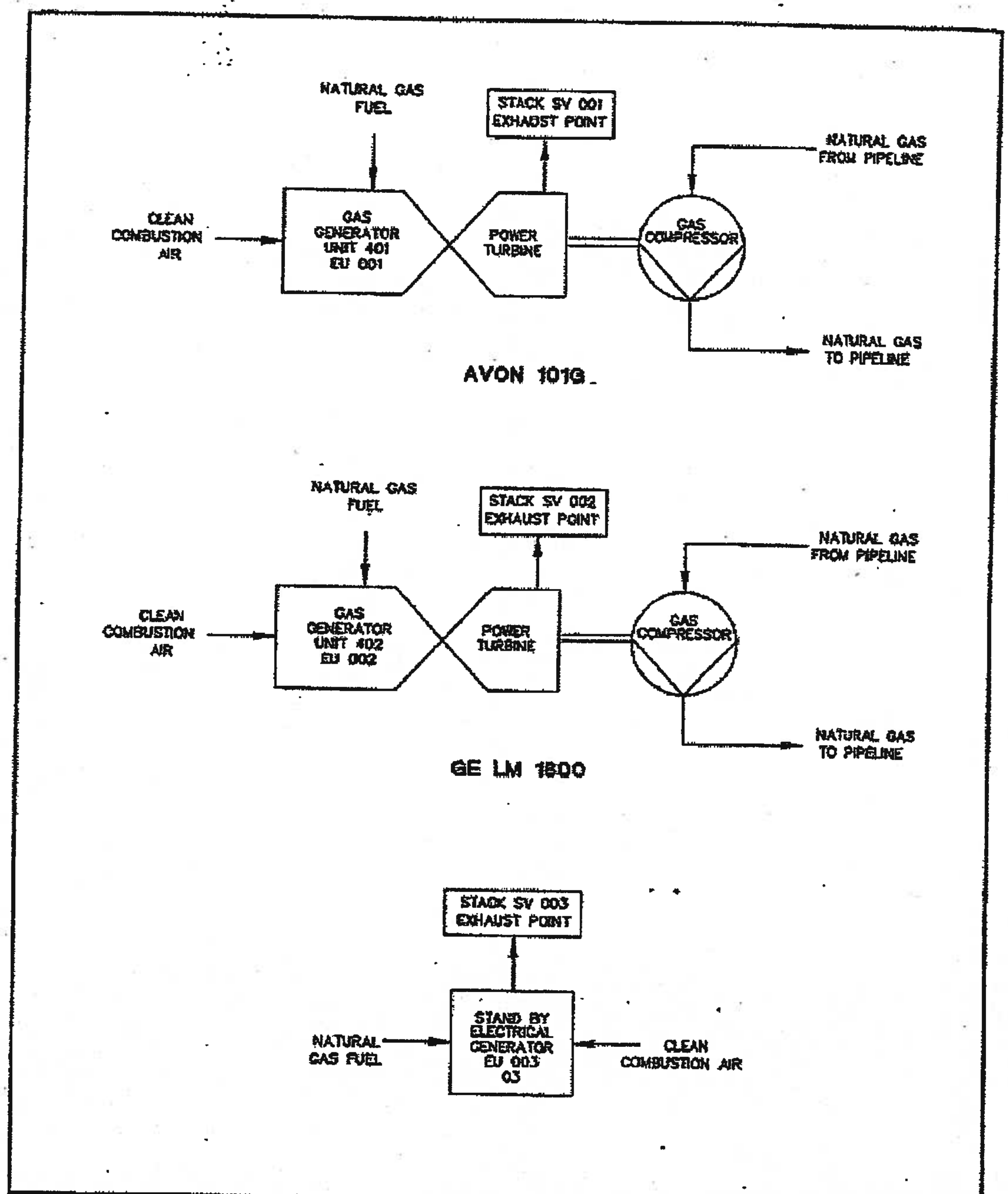
BUILDING DIMENSIONS			
BUILDING DESIGNATION	LENGTH X WIDTH	ROOF HEIGHT AT EDGE	ROOF HEIGHT AT PEAK
401	65.3' X 21'	22.25'	24.88'
402	71.5' X 46'	31.5'	40.00'
SERVICE BLDG	126' X 26.3'	13'	17.33'
WAREHOUSE	88' X 62.8'	23'	33.47'

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

STACK LOCATION MAP
AIR PERMITTING APPLICATION
DEER RIVER COMPRESSOR STATION – NO. 4 (CS #4)
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
M.P. 201.17 – ITASCA COUNTY, MINNESOTA

DRAWN BY: JAG	8-2-95	APP'D BY: VKG	8-2-95
DWG. FILE	MX522AD2	DWG. NO.	CMXX-95-22AD

Appendix C: Process Flow Diagrams



GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

PROCESS FLOW DIAGRAM
AIR PERMITTING APPLICATION
DEER RIVER COMPRESSOR STATION – NO. 4 (CS #4)
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
M.P. 201.17 – ITASCA COUNTY, MINNESOTA

DRAWN BY: LCL	DATE: 09-07-95
APP'D BY: RC	DATE: 09-07-95
PROJECT: CMXX-95-22AD	
DWG. NO. MX522AD3	
SHEET 1 OF 1	
FIGURE NO. 1	

Appendix D: FERC Gas Tariff, General Terms and Conditions

FERC Gas Tariff

Second Revised Volume No. 1

of

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

Filed with

Federal Energy Regulatory Commission

Communications Covering Tariff Sheets be Addressed to:

Robert D. Jackson
Director, Rates and Regulatory Affairs
Great Lakes Gas Transmission Limited Partnership
5250 Corporate Drive
Troy, Michigan 48098
Phone: (248) 205-7400
Fax: (248) 205-7612

GENERAL TERMS AND CONDITIONS

(Continued)

(c) By estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the meter was registering accurately.

(d) These corrections, or any other measurement or data corrections should be processed within 6 months of the production month with a 3 month rebuttal period. This standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard.

7.6 If at any time during the term of service a new method or technique is developed with respect to gas measurement or the determination of the factors used in gas measurement, the new method or technique may be substituted upon mutual agreement by both parties.

7.7 The parties agree to preserve for a period of at least three (3) years or such longer periods as may be required by public authority, all test data, charts and other similar records.

8. QUALITY

8.1 Heating Value

Gas delivered by Shipper to Transporter at each point of receipt shall have a heating value not greater than 1069 Btu's per cubic foot nor less than 967 Btu's. Transporter shall have the right to waive such Btu content limits if, in Transporter's sole opinion, Transporter is able to accept gas with a Btu content outside such limits without affecting Transporter's operations. The heating value shall be determined at intervals of not more than thirty (30) days by means of an instrument(s) of standard manufacture accepted in the industry for this purpose or using a sample of gas representative of the gas stream that is being delivered to Transporter or received from Transporter at the point(s) of receipt or delivery.

In the event, however, that the heating value of Gas received by Transporter at any point drops below 1013 Btu, which is the Btu level at which the MDQs of Service Agreements are currently based and Transporter is unable to Transport a Shipper's Scheduled Daily Delivery due to the drop in the Btu level, Transporter shall utilize the Curtailment provision of Section 13.4 of the General Terms and Conditions, but only for those Shippers from whom Transporter receives Gas at that point.

For the purpose of calculating receipts and deliveries, the heating value of the gas so determined at each such point shall be deemed to remain constant at such point until the next determination.

8.2 Freedom from Objectionable Odor and Matter

The gas received and delivered hereunder:

(a) shall be commercially free (at prevailing pressure and temperature) from objectionable odors, dust, or other solid or liquid matter that might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters and other equipment of Transporter;

(b) shall not contain more than one quarter (1/4) grain of hydrogen sulfide per one hundred (100) cubic feet of gas;

(c) shall not contain more than twenty (20) grains of total sulfur (including the sulfur in any hydrogen sulfide and mercaptans) per one hundred (100) cubic feet of gas;

(d) shall not at any time have an oxygen content in excess of one percent (1%) by volume and the parties shall make every reasonable effort to keep the gas free of oxygen;

GENERAL TERMS AND CONDITIONS

(continued)

(e) shall not contain as nearly as practicable any free water nor contain more than four (4) pounds of water vapor per million cubic feet of gas;

(f) shall not contain more than two percent (2%) by volume of carbon dioxide;

(g) shall be at a temperature not in excess of one hundred twenty degrees (120°) Fahrenheit or less than twenty degrees (20°) Fahrenheit; and

(h) shall not contain more than three percent (3%) by volume of nitrogen.

8.3 Failure to Meet Specifications

Should any gas tendered for delivery by Shipper fail at any time to conform to any of the specifications of this section, Transporter shall notify Shipper of the failure and Transporter may suspend all or a portion of the receipt of any such gas if it will jeopardize operation of the Transporter's system or will cause Transporter to suffer an economic loss; and Transporter shall be relieved of all obligations for the duration of such time as the gas does not meet the specifications.

8.4 Commingling

It is recognized that gas delivered by Shipper will be commingled with other gas transported by Transporter. Accordingly, the gas of Shipper shall be subject to such changes in heat content as may result from such commingling and Transporter shall, notwithstanding any other provision in this FERC Gas Tariff, Second Revised Volume No. 1, herein, be under no obligation to redeliver for Shipper's account, gas of a heat content identical to that caused to be delivered by Shipper to Transporter.

9. BILLING AND PAYMENT

9.1 Billing

On or before the fourth (4th) business day of each Month, Transporter shall e-mail to Shipper a notification that the statement of the amount due for the preceding Month under Transporter's applicable rate schedule(s) is available for viewing on Transporter's Web Site. In computing amounts due, Transporter may utilize estimates of the quantity of gas received from or delivered to Shipper during a Month in place of actual quantities when actual quantities are not reasonably available; provided, however, that adjustments shall be made as soon as is reasonably possible for differences between estimated and actual quantities. Any additional invoice backup shall accompany or precede the invoice.

When information necessary for billing purposes is in the control of Shipper, Shipper shall furnish that information to Transporter on or before the second (2nd) Business Day of the Month following the Month of delivery.

9.2 Examination of Records

Both Transporter and Shipper have the right to examine, at reasonable times, books, records and charts of the other party to the extent necessary to verify the accuracy of any statement, charge or computation made under or pursuant to any of the provisions hereof.

Appendix E: Emission Calculation Spreadsheets

- Table 1 - Potential Emissions Summary
- Table 2 - Potential Emissions of Hazardous Air Pollutants
- Table 3 - 2007 Actual Emissions of Criteria and Hazardous Air Pollutants
- Table 4 - 2007 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Turbine EU001
- Table 5 - 2007 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Turbine EU002
- Table 6 - 2007 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for a Natural Gas-Fired Standby Electrical Generator

Appendix E - Table 1 - Potential Emissions Summary

For EPA Part 71 Form PTE

Criteria Pollutant	NOx	VOC	SO2	PM10	CO	Lead	HAP
Turbine Unit 401 (001)	201.70	1.72	2.79	5.41	485.07	0.00	0.84
Turbine Unit 402 (002)	430.36	1.69	2.74	5.32	8.70	0.00	0.83
Standby Generator (003)	18.08	3.72	0.02	0.31	9.99	0.00	2.51
Total PTE Emissions (tpy)	**650.14**	**7.13**	**5.55**	**11.05**	**503.76**	**0.00**	**4.18**

Appendix E - Table 2 - Potential Emissions of Hazardous Air Pollutants

For EPA Part 71 Form PTE
Potential Emissions - HAPs - TPY

Hazardous Air Pollutant (HAP)	CAS Number	Turbine Unit 401 (001)	Turbine Unit 402 (002)	Standby Generator (003)	Total PTE Emissions (tpy)
1,1,2,2-Tetrachloroethane	79-34-5	-	-	0.00	0.00
1,1,2-Trichloroethane	79-00-5	-	-	0.00	0.00
1,3-Butadiene	106-99-0	0.00	0.00	0.03	0.03
1,3-Dichloropropene	542-75-6	-	-	0.00	0.00
2,2,4-Trimethylpentane	540-84-1	-	-	0.03	0.03
2-Methylnaphthalene	91-57-6*	-	-	0.00	0.00
3-Methylchloranthrene	56-49-5*	-	-	-	0.00
7,12-Dimethylbenz(a)anthracene	57-97-6*	-	-	-	0.00
Acenaphthene	83-32-9*	-	-	0.00	0.00
Acenaphthylene	203-96-8*	-	-	0.00	0.00
Acetaldehyde	75-07-0	0.03	0.03	0.24	0.31
Acrolein	107-02-8	0.01	0.01	0.25	0.26
Anthracene	120-12-7*	-	-	0.00	0.00
Arsenic	7440-38-2	-	-	-	0.00
Benz(a)anthracene	56-55-3*	-	-	0.00	0.00
Benzene	71-43-2	0.01	0.01	0.06	0.08
Benzo(a)pyrene	50-32-8*	-	-	0.00	0.00
Benzo(b)fluoranthene	205-99-2*	-	-	0.00	0.00
Benzo(e)pyrene	192-97-2*	-	-	0.00	0.00
Benzo(g,h,i)perylene	191-24-2*	-	-	0.00	0.00
Benzo(k)fluoranthene	205-82-3*	-	-	0.00	0.00
Beryllium	7440-41-7	-	-	-	0.00
Biphenyl	92-52-4	-	-	0.00	0.00
Cadmium	7440-43-9	-	-	-	0.00
Carbon Tetrachloride	56-23-5	-	-	0.00	0.00
Chlorobenzene	108-90-7	-	-	0.00	0.00
Chloroform	67-66-3	-	-	0.00	0.00
Chromium	7440-47-3	-	-	-	0.00
Chrysene	218-01-9*	-	-	0.00	0.00
Cobalt	7440-48-4	-	-	-	0.00
Dibenzo(a,h)anthracene	53-70-3*	-	-	-	0.00
Dichlorobenzene	25321-22-6	-	-	-	0.00
Ethylbenzene	100-41-4	0.03	0.03	0.00	0.06
Ethylene Dibromide	106-93-4	-	-	0.00	0.00
Fluoranthene	206-44-0*	-	-	0.00	0.00
Fluorene	86-73-7*	-	-	0.00	0.00
Formaldehyde	50-00-0	0.58	0.57	1.74	2.89
Indeno(1,2,3-c,d)pyrene	193-39-5*	-	-	0.00	0.00
Manganese	7439-96-5	-	-	-	0.00
Mercury	7439-97-6	-	-	-	0.00
Methanol	67-56-1	-	-	0.08	0.08
Methylene Chloride	74-87-3	-	-	0.00	0.00
Naphthalene	91-20-3	0.00	0.00	0.00	0.01
n-Hexane	110-54-3	-	-	0.01	0.01
Nickel	7440-02-0	-	-	-	0.00
PAH	130498-29-2*	0.00	0.00	0.00	0.01
Perylene	198-55-0*	-	-	0.00	0.00
Phenanthrene	85-01-8*	-	-	0.00	0.00
Phenol	108-95-2	-	-	0.00	0.00
Propylene Oxide	75-56-9	0.02	0.02	-	0.05
Pyrene	129-00-0*	-	-	0.00	0.00
Selenium	7782-49-2	-	-	-	0.00
Styrene	100-42-5	-	-	0.00	0.00
Toluene	108-88-3	0.11	0.10	0.03	0.24
Vinyl Chloride	75-01-4	-	-	0.00	0.00
Xylene	1330-20-7	0.05	0.05	0.01	0.11
Total HAP		0.84	0.83	2.51	4.18

* Polycyclic Organic Matter (POM)

Total HAP (tpy)	4.18
Single HAP Emitted in Largest	Formaldehyde
Amount (tpy)	2.89

Appendix E - Table 3 - 2007 Actual Emissions of Criteria and Hazardous Air Pollutants

For EPA Part 71 Form FEE Part D.

Criteria Pollutant	NOx	VOC	SO2	PM10	CO	Lead	HAP
Turbine Unit 401 (001)	95.1	0.8	1.3	2.6	228.6	0.0	0.4
Turbine Unit 402 (002)	221.8	0.9	1.4	2.7	4.5	0.0	0.4
Standby Generator (003)	0.2	0.0	0.0	0.0	0.1	0.0	0.0
Total 2007 Actual Emissions (tpy)	317.0	1.7	2.7	5.3	233.2	0.0	0.9

For EPA Part 71 Form FEE Part E. HAP Identification

Identifier	Hazardous Air Pollutant (HAP)	CAS Number
HAP 1	1,1,2,2-Tetrachloroethane	79-34-5
HAP 2	1,1,2-Trichloroethane	79-00-5
HAP 3	1,3-Butadiene	106-99-0
HAP 4	1,3-Dichloropropene	542-75-6
HAP 5	2,2,4-Trimethylpentane	540-84-1
HAP 6	2-Methylnaphthalene	91-57-6*
HAP 7	3-Methylchloranthrene	56-49-5*
HAP 8	7,12-Dimethylbenz(a)anthracene	57-97-6*
HAP 9	Acenaphthene	83-32-9*
HAP 10	Acenaphthylene	203-96-8*
HAP 11	Acetaldehyde	75-07-0
HAP 12	Acrolein	107-02-8
HAP 13	Anthracene	120-12-7*
HAP 14	Arsenic	7440-38-2
HAP 15	Benz(a)anthracene	56-55-3*
HAP 16	Benzene	71-43-2
HAP 17	Benzo(a)pyrene	50-32-8*
HAP 18	Benzo(b)fluoranthene	205-99-2*
HAP 19	Benzo(e)pyrene	192-97-2*
HAP 20	Benzo(g,h,i)perylene	191-24-2*
HAP 21	Benzo(k)fluoranthene	205-82-3*
HAP 22	Beryllium	7440-41-7
HAP 23	Biphenyl	92-52-4
HAP 24	Cadmium	7440-43-9
HAP 25	Carbon Tetrachloride	56-23-5
HAP 26	Chlorobenzene	108-90-7
HAP 27	Chloroform	67-66-3
HAP 28	Chromium	7440-47-3
HAP 29	Chrysene	218-01-9*
HAP 30	Cobalt	7440-48-4
HAP 31	Dibenzo(a,h)anthracene	53-70-3*
HAP 32	Dichlorobenzene	25321-22-6
HAP 33	Ethylbenzene	100-41-4
HAP 34	Ethylene Dibromide	106-93-4
HAP 35	Fluoranthene	206-44-0*
HAP 36	Fluorene	86-73-7*
HAP 37	Formaldehyde	50-00-0
HAP 38	Indeno(1,2,3-c,d)pyrene	193-39-5*
HAP 39	Manganese	7439-96-5
HAP 40	Mercury	7439-97-6
HAP 41	Methanol	67-56-1
HAP 42	Methylene Chloride	74-87-3
HAP 43	Naphthalene	91-20-3
HAP 44	n-Hexane	110-54-3
HAP 45	Nickel	7440-02-0
HAP 46	PAH	130498-29-2*
HAP 47	Perylene	198-55-0*
HAP 48	Phenanthrene	85-01-8*
HAP 49	Phenol	108-95-2
HAP 50	Propylene Oxide	75-56-9
HAP 51	Pyrene	129-00-0*
HAP 52	Selenium	7782-49-2
HAP 53	Styrene	100-42-5
HAP 54	Toluene	108-88-3
HAP 55	Vinyl Chloride	75-01-4
HAP 56	Xylene	1330-20-7

* Polycyclic Organic Matter (POM)

Appendix E - Table 3 - 2007 Actual Emissions of Criteria and Hazardous Air Pollutants

For EPA Part 71 Form FEE Part E. HAP Emissions

Hazardous Air Pollutant (HAP)	1,1,2,2-Tetrachloroethane	1,1,2-Trichloroethane	1,3-Butadiene	1,3-Dichloropropene	2,2,4-Trimethylpentane	2-Methylnaphthalene	3-Methylchloranthrene
CAS Number	79-34-5	79-00-5	106-99-0	542-75-6	540-84-1	91-57-6*	56-49-5*
HAP Number	HAP 1	HAP 2	HAP 3	HAP 4	HAP 5	HAP 6	HAP 7
Turbine Unit 401 (001)	-	-	0.0	-	-	-	-
Turbine Unit 402 (002)	-	-	0.0	-	-	-	-
Standby Generator (003)	0.0	0.0	0.0	0.0	0.0	0.0	-
Total 2007 Actual Emissions (tpy)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Hazardous Air Pollutant (HAP)	7,12-Dimethylbenz(a)anthracene	Acenaphthene	Acenaphthylene	Acetaldehyde	Acrolein	Anthracene	Arsenic
CAS Number	57-97-6*	83-32-9*	203-96-8*	75-07-0	107-02-8	120-12-7*	7440-38-2
HAP Number	HAP 8	HAP 9	HAP 10	HAP 11	HAP 12	HAP 13	HAP 14
Turbine Unit 401 (001)	-	-	-	0.0	0.0	-	-
Turbine Unit 402 (002)	-	-	-	0.0	0.0	-	-
Standby Generator (003)	-	0.0	0.0	0.0	0.0	0.0	-
Total 2007 Actual Emissions (tpy)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Hazardous Air Pollutant (HAP)	Benz(a)anthracene	Benzene	Benzo(a)pyrene	Benzo(b)fluoranthene	Benzo(e)pyrene	Benzo(g,h,i)perylene	Benzo(k)fluoranthene
CAS Number	56-55-3*	71-43-2	50-32-8*	205-99-2*	192-97-2*	191-24-2*	205-82-3*
HAP Number	HAP 15	HAP 16	HAP 17	HAP 18	HAP 19	HAP 20	HAP 21
Turbine Unit 401 (001)	-	0.0	-	-	-	-	-
Turbine Unit 402 (002)	-	0.0	-	-	-	-	-
Standby Generator (003)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total 2007 Actual Emissions (tpy)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Hazardous Air Pollutant (HAP)	Beryllium	Biphenyl	Cadmium	Carbon Tetrachloride	Chlorobenzene	Chloroform	Chromium
CAS Number	7440-41-7	92-52-4	7440-43-9	56-23-5	108-90-7	67-66-3	7440-47-3
HAP Number	HAP 22	HAP 23	HAP 24	HAP 25	HAP 26	HAP 27	HAP 28
Turbine Unit 401 (001)	-	-	-	-	-	-	-
Turbine Unit 402 (002)	-	-	-	-	-	-	-
Standby Generator (003)	-	0.0	-	0.0	0.0	0.0	-
Total 2007 Actual Emissions (tpy)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Hazardous Air Pollutant (HAP)	Chrysene	Cobalt	Dibenzo(a,h)anthracene	Dichlorobenzene	Ethylbenzene	Ethylene Dibromide	Fluoranthene
CAS Number	218-01-9*	7440-48-4	53-70-3*	25321-22-6	100-41-4	106-93-4	206-44-0*
HAP Number	HAP 29	HAP 30	HAP 31	HAP 32	HAP 33	HAP 34	HAP 35
Turbine Unit 401 (001)	-	-	-	-	0.0	-	-
Turbine Unit 402 (002)	-	-	-	-	0.0	-	-
Standby Generator (003)	0.0	-	-	-	0.0	0.0	0.0
Total 2007 Actual Emissions (tpy)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Hazardous Air Pollutant (HAP)	Fluorene	Formaldehyde	Indeno(1,2,3-c,d)pyrene	Manganese	Mercury	Methanol	Methylene Chloride
CAS Number	86-73-7*	50-00-0	193-39-5*	7439-96-5	7439-97-6	67-56-1	74-87-3
HAP Number	HAP 36	HAP 37	HAP 38	HAP 39	HAP 40	HAP 41	HAP 42
Turbine Unit 401 (001)	-	0.3	-	-	-	-	-
Turbine Unit 402 (002)	-	0.3	-	-	-	-	-
Standby Generator (003)	0.0	0.0	0.0	-	-	0.0	0.0
Total 2007 Actual Emissions (tpy)	0.0	0.6	0.0	0.0	0.0	0.0	0.0

Hazardous Air Pollutant (HAP)	Naphthalene	n-Hexane	Nickel	PAH	Perylene	Phenanthrene	Phenol
CAS Number	91-20-3	110-54-3	7440-02-0	130498-29-2*	198-55-0*	85-01-8*	108-95-2
HAP Number	HAP 43	HAP 44	HAP 45	HAP 46	HAP 47	HAP 48	HAP 49
Turbine Unit 401 (001)	0.0	-	-	0.0	-	-	-
Turbine Unit 402 (002)	0.0	-	-	0.0	-	-	-
Standby Generator (003)	0.0	0.0	-	0.0	0.0	0.0	0.0
Total 2007 Actual Emissions (tpy)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Hazardous Air Pollutant (HAP)	Propylene Oxide	Pyrene	Selenium	Styrene	Toluene	Vinyl Chloride	Xylene	Total Actual HAP
CAS Number	75-56-9	129-00-0*	7782-49-2	100-42-5	108-88-3	75-01-4	1330-20-7	
HAP Number	HAP 50	HAP 51	HAP 52	HAP 53	HAP 54	HAP 55	HAP 56	
Turbine Unit 401 (001)	0.0	-	-	-	0.1	-	0.0	0.4
Turbine Unit 402 (002)	0.0	-	-	-	0.1	-	0.0	0.4
Standby Generator (003)	-	0.0	-	0.0	0.0	0.0	0.0	0.0
Total 2007 Actual Emissions (tpy)	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.9

Appendix E - Table 4 - 2007 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Turbine Unit 401

For EPA Part 71 Form EMISS, Unit 001

Equipment Information	Notes	
Facility:		Deer River CS4
AQD Emission Unit ID:		001
Unit No.		401
Make:		Rolls Royce/Avon
Model Number:		101G
Installation date:		1971
AQD Stack Number:		SV001
Stack Height (feet):		48.08
Stack Diameter (feet):		5.8
Fuel Burned:		Natural gas
Assumptions:		
Turbine Rated Capacity, (hp):		18,000
PTE Hours of Operation:		8,760
Brake-Specific Fuel Consumption (Btu/hp-hr):	7	10,400
2007 Actual Fuel Use (MMscf/year):		757.77
Calculated Max. Annual Fuel Use (MMscf/year):		1,607.72
Calculated Max. Hourly Fuel Use (MMscf/hour):		0.184
Calculated Max. Heat Input (MMBtu/hr)		187.2
Fuel Heat Content (Btu/scf):		1,020

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Notes	AP-42 Emission Factor (lb/MMbtu)	Stack Test Emission Factor plus 20% Safety Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2007 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	1	3.20E-01	2.46E-01	250.920	95.07	46.05	201.70
VOC	2	2.10E-03		2.142	0.81	0.39	1.72
SO2	3	3.40E-03		3.468	1.31	0.64	2.79
PM=PM10	2,4	6.60E-03		6.732	2.55	1.24	5.41
CO	1	8.20E-02	5.92E-01	603.432	228.63	110.75	485.07
Lead	2	neg			0.00	0.00	0.00

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	Notes	AP-42 Emission Factor (lb/MMbtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2007 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
1,3-Butadiene	5	4.30E-07	4.39E-04	0.00	0.00	0.00
Acetaldehyde	5	4.00E-05	4.08E-02	0.02	0.01	0.03
Acrolein	5	6.40E-06	6.53E-03	0.00	0.00	0.01
Benzene	5	1.20E-05	1.22E-02	0.00	0.00	0.01
Ethylbenzene	5	3.20E-05	3.26E-02	0.01	0.01	0.03
Formaldehyde	5	7.10E-04	7.24E-01	0.27	0.13	0.58
Naphthalene	5	1.30E-06	1.33E-03	0.00	0.00	0.00
PAH	5,6	2.20E-06	2.24E-03	0.00	0.00	0.00
Propylene Oxide	5	2.90E-05	2.96E-02	0.01	0.01	0.02
Toluene	5	1.30E-04	1.33E-01	0.05	0.02	0.11
Xylene	5,8	6.40E-05	6.53E-02	0.02	0.01	0.05
			Total HAP	0.40	0.19	0.84

Notes
1. Stack test (March 29, 2005) emission factors have a 20% safety factor was added to each emission factor to account for operational variability.
2. Emission factors from AP-42 Table 3.1-2a. Emission factor for lead listed as "No Data".
3. SO2 emissions factor from AP-42 Table 3.1-2a, Note h.
4. It is assumed that Total PM = PM10.
5. HAP emission factors from AP-42, Table 3.1-3, April, 2004.
6. For inventory purposes, assume Polycyclic Aromatic Hydrocarbons (PAH) is the same as Polycyclic Organic Matter (POM).
7. Emission factors converted from lb/MMBtu to lb/MMscf using average brake-specific fuel consumption (BSFC) = 10,400 Btu/hp-hr.
8. Mixed xylenes

Appendix E - Table 5 - 2007 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Turbine Unit 402

For EPA Part 71 Form EMISS, Unit 002

Equipment Information	Notes	
Facility:		Deer River CS4
AQD Emission Unit ID:		002
Unit No.		402
Make:		General Electric
Model Number:		LM1600
Installation date:		1993
AQD Stack Number:		SV002
Stack Height (feet):		40.0
Stack Diameter (inches):		6.60
Fuel Burned:		Natural gas
Assumptions:		
Turbine Rated Capacity, (hp):		23,000
PTE Hours of Operation:		8,760
Brake-Specific Fuel Consumption (Btu/hp-hr):	7	8,000
2007 Actual Fuel Use (MMscf/year):		814.28
Calculated Max. Annual Fuel Use (MMscf/year):		1,580.24
Calculated Max. Hourly Fuel Use (MMscf/hour):		0.180
Calculated Max. Heat Input (MMBtu/hr)		184.0
Fuel Heat Content (Btu/scf):		1,020

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Notes	AP-42 Emission Factor (lb/MMbtu)	Stack Test Emission Factor plus 20% Safety Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2007 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	1	3.20E-01	5.34E-01	544.680	221.76	98.26	430.36
VOC	2	2.10E-03		2.142	0.87	0.39	1.69
SO2	3	3.40E-03		3.468	1.41	0.63	2.74
PM=PM10	2,4	6.60E-03		6.732	2.74	1.21	5.32
CO	1	8.20E-02	1.08E-02	11.016	4.49	1.99	8.70
Lead	2	neg			0.00	0.00	0.00

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	Notes	AP-42 Emission Factor (lb/MMbtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2007 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
1,3-Butadiene	5	4.30E-07	4.39E-04	0.00	0.00	0.00
Acetaldehyde	5	4.00E-05	4.08E-02	0.02	0.01	0.03
Acrolein	5	6.40E-06	6.53E-03	0.00	0.00	0.01
Benzene	5	1.20E-05	1.22E-02	0.00	0.00	0.01
Ethylbenzene	5	3.20E-05	3.26E-02	0.01	0.01	0.03
Formaldehyde	5	7.10E-04	7.24E-01	0.29	0.13	0.57
Naphthalene	5	1.30E-06	1.33E-03	0.00	0.00	0.00
PAH	5,6	2.20E-06	2.24E-03	0.00	0.00	0.00
Propylene Oxide	5	2.90E-05	2.96E-02	0.01	0.01	0.02
Toluene	5	1.30E-04	1.33E-01	0.05	0.02	0.10
Xylene	5,8	6.40E-05	6.53E-02	0.03	0.01	0.05
			Total HAP	0.43	0.19	0.83

Notes
1. Stack test (March 30, 2005) emission factors have a 20% safety factor was added to each emission factor to account for operational variability.
2. Emission factors from AP-42 Table 3.1-2a. Emission factor for lead listed as "No Data".
3. SO2 emissions factor from AP-42 Table 3.1-2a, Note h.
4. It is assumed that Total PM = PM10.
5. HAP emission factors from AP-42, Table 3.1-3, April, 2004.
6. For inventory purposes, assume Polycyclic Aromatic Hydrocarbons (PAH) is the same as Polycyclic Organic Matter (POM).
7. Emission factors converted from lb/MMBtu to lb/MMscf using average brake-specific fuel consumption (BSFC) = 8,000 Btu/hp-hr.
8. Mixed xylenes

Appendix E - Table 6 - 2007 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for a Natural Gas-Fired Standby Electrical Generator

For EPA Part 71 Form EMISS, Unit 003

Equipment Information	Notes	
Facility:		Deer River CS4
AQD Emission Unit ID:		003
Unit No.		N/A
Make:		Waukesha
Model Number:		L36GL
Installation date:		1997
AQD Stack Number:		SV003
Stack Height (feet):		24.4
Stack Diameter (inches):		0.67
Fuel Burned:		Natural gas
Assumptions:		
Engine Rated Capacity, (hp):		899
2007 Actual Hours of Operation:		95.1
PTE Hours of Operation:		8,760
Brake-Specific Fuel Consumption (Btu/hp-hr):	5	8,000
Calculated 2007 Actual Fuel Use (MMscf/year):		0.671
Calculated Max. Annual Fuel Use (MMscf/year):		61.77
Calculated Max. Hourly Fuel Use (MMscf/hour):		0.007
Calculated Max. Heat Input (MMBtu/hr)		7.2
Fuel Heat Content (Btu/scf):		1,020

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Notes	Emission Factor (lb/MMbtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2007 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	6	5.74E-01	585.399	0.20	4.13	18.08
VOC	1	1.18E-01	120.360	0.04	0.85	3.72
SO2	1	5.88E-04	0.600	0.00	0.00	0.02
PM10	1	9.99E-03	10.167	0.00	0.07	0.31
CO	1,2	3.17E-01	323.340	0.11	2.28	9.99
Lead	1	not listed		0.00	0.00	0.00

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	Notes	Emission Factor (lb/MMbtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2007 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
1,1,2,2-Tetrachloroethane	3	6.63E-05	6.76E-02	0.00	0.00	0.00
1,1,2-Trichloroethane	3	5.27E-05	5.38E-02	0.00	0.00	0.00
1,3-Butadiene	3	8.20E-04	8.36E-01	0.00	0.01	0.03
1,3-Dichloropropene	3	4.38E-05	4.47E-02	0.00	0.00	0.00
2,2,4-Trimethylpentane	3	8.46E-04	8.63E-01	0.00	0.01	0.03
2-Methylnaphthalene	3	2.14E-05	2.18E-02	0.00	0.00	0.00
Acenaphthene	3	1.33E-06	1.36E-03	0.00	0.00	0.00
Acenaphthylene	3	3.17E-06	3.23E-03	0.00	0.00	0.00
Acetaldehyde	3	7.76E-03	7.92E+00	0.00	0.06	0.24
Acrolein	3	7.78E-03	7.94E+00	0.00	0.06	0.25
Anthracene	3	7.18E-07	7.32E-04	0.00	0.00	0.00
Benz(a)anthracene	3	3.36E-07	3.43E-04	0.00	0.00	0.00
Benzene	3	1.94E-03	1.98E+00	0.00	0.01	0.06
Benzo(a)pyrene	3	5.68E-09	5.79E-06	0.00	0.00	0.00
Benzo(b)fluoranthene	3	8.51E-09	8.68E-06	0.00	0.00	0.00
Benzo(e)pyrene	3	2.34E-08	2.39E-05	0.00	0.00	0.00
Benzo(g,h,i)perylene	3	2.48E-08	2.53E-05	0.00	0.00	0.00
Benzo(k)fluoranthene	3	4.26E-09	4.35E-06	0.00	0.00	0.00
Biphenyl	3	3.95E-06	4.03E-03	0.00	0.00	0.00
Carbon Tetrachloride	3	6.07E-05	6.19E-02	0.00	0.00	0.00
Chlorobenzene	3	4.44E-05	4.53E-02	0.00	0.00	0.00
Chloroform	3	4.71E-05	4.80E-02	0.00	0.00	0.00
Chrysene	3	6.72E-07	6.85E-04	0.00	0.00	0.00
Ethylbenzene	3	1.08E-04	1.10E-01	0.00	0.00	0.00
Ethylene Dibromide	3	7.34E-05	7.49E-02	0.00	0.00	0.00
Fluoranthene	3	3.61E-07	3.68E-04	0.00	0.00	0.00
Fluorene	3	1.69E-06	1.72E-03	0.00	0.00	0.00
Formaldehyde	3	5.52E-02	5.63E+01	0.02	0.40	1.74
Indeno(1,2,3-c,d)pyrene	3	9.93E-09	1.01E-05	0.00	0.00	0.00
Methanol	3	2.48E-03	2.53E+00	0.00	0.02	0.08
Methylene Chloride	3	1.47E-04	1.50E-01	0.00	0.00	0.00
Naphthalene	3	9.63E-05	9.82E-02	0.00	0.00	0.00
n-Hexane	3	4.45E-04	4.54E-01	0.00	0.00	0.01
PAH	3,4	1.34E-04	1.37E-01	0.00	0.00	0.00
Perylene	3	4.97E-09	5.07E-06	0.00	0.00	0.00
Phenanthrene	3	3.53E-06	3.60E-03	0.00	0.00	0.00
Phenol	3	4.21E-05	4.29E-02	0.00	0.00	0.00
Pyrene	3	5.84E-07	5.96E-04	0.00	0.00	0.00
Styrene	3	5.48E-05	5.59E-02	0.00	0.00	0.00
Toluene	3	9.63E-04	9.82E-01	0.00	0.01	0.03
Vinyl Chloride	3	2.47E-05	2.52E-02	0.00	0.00	0.00
Xylene	3	2.68E-04	2.73E-01	0.00	0.00	0.01
			Total HAP	0.03	0.57	2.51

1. Emission factors from AP-42 Table 3.2-2 for 4-stroke lean burn engines.
2. NOx and CO factors are for 90-105% load.
3. HAP emission factors from AP-42, Table 3.2-2, July 2000.
4. For inventory purposes, assume PAH is the same as Polycyclic Organic Matter (POM).
5. Emission factors converted from lb/MMBtu to lb/MMscf using average brake-specific fuel consumption (BSFC) = 8,000 Btu/hp-hr.
6. NOx emission factor from manufacturer's specifications: 2.0 gm/hp-hr / 8000 btu/hp-hr / 435.6 gm/lb x 1,000,000 btu/MMBtu = 0.574 lb/MMBtu NOx

Appendix F: EPA Compilation of Air Pollutant Emission Factors, AP-42, Supplement F, July 1993, Emission Factor Information

- Chapter 1.4 Natural Gas Combustion
- Chapter 3.1 Stationary Gas Turbines
- Chapter 3.2 Natural Gas-Fired Reciprocating Engines
- Chapter 3.3 Gasoline and Diesel Industrial Engines

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b] Emission Factor (lb/10^6 scf)	NO_x[b] Emission Factor Rating	CO Emission Factor (lb/10^6 scf)	CO Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from lb/10^6 scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_x emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_x emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds.
VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)\ (CON)\ (C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2×10^4 $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines[b]		Digester Gas-Fired Turbines[d]	
	(lb/MMBtu)[c]	Emission Factor Rating	(lb/MMBtu)[e]	Emission Factor Rating
CO_2[f]	50	D	27	C
Lead	ND	NA	< 3.4 E-06[g]	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO_2	4.5 E-02	C	6.5 E-03	D
VOC[h]	1.3 E-02	B	5.8 E-03	D

[a] Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCC for landfill gas-fired turbines is 2-03-008-01.

[c] Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 400.

[d] SCC for digester gas-fired turbine include 2-03-007-01.

[e] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 600.

[f] For landfill gas and digester gas, CO_2 is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).

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

[h] Based on adding the formaldehyde emissions to the NMHC.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.
[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".
[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.
[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.
[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.
[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES (Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Acenaphthylene[k]	5.53 E-06	C
Acetaldehyde[k,l]	8.36 E-03	A
Acrolein[k,l]	5.14 E-03	A
Benzene[k]	4.40 E-04	A
Benzo(b)fluoranthene[k]	1.66 E-07	D
Benzo(e)pyrene[k]	4.15 E-07	D
Benzo(g,h,i)perylene[k]	4.14 E-07	D
Biphenyl[k]	2.12 E-04	D
Butane	5.41 E-04	D
Butyr/Isobutyraldehyde	1.01 E-04	C
Carbon Tetrachloride[k]	<3.67 E-05	E
Chlorobenzene[k]	<3.04 E-05	E
Chloroethane	1.87 E-06	D
Chloroform[k]	<2.85 E-05	E
Chrysene[k]	6.93 E-07	C
Cyclopentane	2.27 E-04	C
Ethane	1.05 E-01	C
Ethylbenzene[k]	3.97 E-05	B
Ethylene Dibromide[k]	<4.43 E-05	E
Fluoranthene[k]	1.11 E-06	C
Fluorene[k]	5.67 E-06	C
Formaldehyde[k,l]	5.28 E-02	A
Methanol[k]	2.50 E-03	B
Methylcyclohexane	1.23 E-03	C
Methylene Chloride[k]	2.00 E-05	C
n-Hexane[k]	1.11 E-03	C
n-Nonane	1.10 E-04	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES
(Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
n-Octane	3.51 E-04	C
n-Pentane	2.60 E-03	C
Naphthalene[k]	7.44 E-05	C
PAH[k]	2.69 E-05	D
Phenanthrene[k]	1.04 E-05	D
Phenol[k]	2.40 E-05	D
Propane	4.19 E-02	C
Pyrene[k]	1.36 E-06	C
Styrene[k]	<2.36 E-05	E
Tetrachloroethane[k]	2.48 E-06	D
Toluene[k]	4.08 E-04	B
Vinyl Chloride[k]	1.49 E-05	C
Xylene[k]	1.84 E-04	B

[a] Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM10, "uncontrolled" means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, "uncontrolled" means no oxidation control; the data set may include units with control techniques used for NOx control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM-10 = Particulate Matter • 10 microns (• m) aerodynamic diameter. A "<" sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

[b] Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$lb/hp\text{-}hr = (lb/MMBtu)(heat\ input,\ MMBtu/hr)(1/operating\ HP,\ 1/hp)$$

[c] Emission tests with unreported load conditions were not included in the data set.

[d] Based on 99.5% conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10^6 scf, and

h = heating value of natural gas (assume 1020 Btu/scf at 60 °F).

[e] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content in natural gas of 2,000 gr/10^6scf.

[f] Emission factor for TOC is based on measured emission levels from 22 source tests.

[g] Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor. Measured emission factor for methane compares well with the calculated emission factor, 1.31 lb/MMBtu vs. 1.25 lb/MMBtu, respectively.

[h] VOC emission factor is based on the sum of the emission factors for all speciated organic compounds less ethane and methane.

[i] Considered ≤ 1 μm in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).

[j] PM Condensable = PM Condensable Inorganic + PM-Condensable Organic

[k] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

[l] For lean burn engines, aldehyde emissions quantification using CARB 430 may reflect interference with the sampling compounds due to the nitrogen concentration in the stack. The presented emission factor is based on FTIR measurements. Emissions data based on CARB 430 are available in the background report.

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01) Emission Factor (lb/hp-hr) (power output)	Gasoline Fuel Emission Factor (lb/MMBtu) (fuel input)	Diesel Fuel (SCC 2-02-001-02, 2-03-001-01) Emission Factor (lb/hp-hr) (power output)	Diesel Fuel Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING
NO_x	0.011	1.63	0.031	4.41	D
CO	0.439	62.7	6.68 E-03	0.95	D
SO_x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10[b]	7.21 E-04	0.10	2.20 E-03	0.31	D
CO_2[c]	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

[a] References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

[b] PM-10 = particulate matter less than or equal to 10 μm aerodynamic diameter. All particulate is assumed to be ≤ 1 μm in size.

[c] Assumes 99% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene[b]	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

Appendix G: Emission Unit Heat Rate Factor (Btu/HP-hr) Calculation Spreadsheet

Emission Unit Btu/hp-hr Calculations

Unit No.	Make/Model	Test 1 Btu/hp-hr	Test 2 Btu/hp-hr	Test 3 Btu/hp-hr	Test 4 Btu/hp-hr
201	Avon 101G	9352	9260	9573	9699
401	Avon 101G	9754	9839	9453	9331
601	Avon 101G	10217	10592	10237	10861
303	LM1600	6950	6930	6998	6999
503	LM1600	7104	7160	7277	7277

Average for all like units operated at 100 % load:

	Tested Btu/hp-hr
Avon 101G	9847.3
LM1600	7086.9

Student's t Distribution = Average + [t value*(std.dev./sqrt n)]

	n	n-1	sqrt of n	t value (99%)
Avon 101G	12	11	3.46	3.106
LM1600	8	7	2.83	3.499

	Tested (Btu/hp-hr) Avon 76G	LM1600
Standard Deviation	521.3	139.8

Student's t Distribution (@ 99%confidence interval)

	Tested
Avon 101G	10314.7
LM1600	7259.9

Use 10,400 Btu/hp-hr for Avon 101G.
Use 8,000 Btu/hp-hr for General Electric LM1600.

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01-Aug-95

Appendix H: Regulatory Review and Compliance Plan

Appendix H
Regulatory Review and Compliance Plan
Great Lakes Gas Transmission Limited Partnership
Deer River Compressor Station No. 4
Deer River, Minnesota

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Regulatory Review and Compliance Plan
Great Lakes Gas Transmission Limited Partnership
Deer River Compressor Station No. 4
Deer River, Minnesota

I. FEDERAL REGULATIONS

1. National Emission Standards for Hazardous Air Pollutants (NESHAP) Requirements

Cite: 40 CFR 61 and 40 CFR 63, Emission Standards for Hazardous Air Pollutants

NESHAP requirements, 40 CFR 61: 40 CFR 61 identifies industries that have specific NESHAP requirements and identifies hazardous air pollutants associated with these industries. The natural gas pipeline transportation industry, of which Great Lakes Gas Transmission Limited Partnership (Great Lakes) is a member, is not among those industries included on this list. The Deer River Compressor Station No. 4 (CS4) does not emit any of the pollutants listed in 40 CFR 61. Therefore, CS4 is not subject to 40 CRF 61 NESHAP requirements.

NESHAP requirements, 40 CFR 63: During the combustion of natural gas, CS4 emission units emit pollutants that are included on the list of 188 Hazardous Air Pollutants (HAPs) listed in 40 CFR 63. The majority of HAPs are emitted from CS4 as non-methane organic compounds. The highest potential emissions are of formaldehyde, acetaldehyde, acrolein, and toluene, with negligible amounts of other species. Based on AP-42 emission factors, the potential to emit (PTE) for the HAPs is less than 10 tons per year (TPY) of any single HAP and less than 25 TPY for the aggregate of all HAPs emitted. CS4 has a PTE of 4.18 TPY for all HAPs emitted. Therefore, CS4 is not subject to 40 CFR 63 NESHAP requirements.

2. New Source Review (NSR) Requirements

Cite: 40 CFR 52.21, Prevention of Significant Deterioration (PSD)

The Deer River area is considered an attainment area for all criteria pollutants (40 CFR 50). As a result, the emissions from a new source or the modification of an existing source must be reviewed for applicability under 40 CFR 52, Section 52.21 "Prevention of Significant Deterioration of Air Quality" (the PSD rule). NSR requirements apply either to a new major source (exceeding 100 TPY of any criteria pollutant if the facility is on the list of 28 industrial categories [40 CFR 52.21(b)(1)(i)(a)] or 250 TPY if not on the list of industrial categories) or to a significant modification (an additional 40 TPY of nitrogen oxides (NO_X) or 100 TPY of the remaining criteria pollutants) to a major source.

Natural gas pipeline transportation is not among the 28 industries categories listed in the PSD rules as being major sources if the PTE is equal to or greater than 100 TPY of any single regulated pollutant [40 CFR 52.21(b)(1)(i)(a)]. However, CS4 does have a PTE of more than 250 TPY of carbon monoxide (CO) and NO_X. Based on emission factors from AP-42, manufacturer's test data, and emission factors calculated from stack test data, the facility has a PTE of 650.14 TPY NO_X and 503.76 TPY CO. Therefore, CS4 is considered a major source under the federal PSD rules [40 CFR 52.21(b)(1)(i)(b)].

CS4 was built prior to August 7, 1980, the date of applicability for PSD. One modification to the facility was made after August 7, 1980 (the full replacement in 1993 of two Orenda turbines with a new GE LM 1600 turbine unit, EU002). Consequently, NSR applicability to individual sources would be based upon installation date and the mass of emittants.

EU001 was installed in 1971 which is prior to the August 7, 1980 date of applicability for PSD. Therefore, EU001 is not subject to NSR.

The installation of EU002 in 1993 as a replacement for the two Orenda gas generator units was not considered a significant modification to a PSD major stationary source because the replacement resulted in a non-significant net emissions increase to the major stationary source, as detailed in the Construction Permit Application. This was also confirmed by the

Minnesota Pollution Control Agency (MPCA) in the issuance of Air Emission Facility Permit No. 365E-92-OT-1, dated July 9, 1992. Because the installation of EU002 resulted in a non-significant net emissions increase to a major stationary source, EU002 is not subject to NSR.

3. National Ambient Air Quality Standards (NAAQS)

Cite: 1990 Clear Air Act, as amended, Sections 109 and 160-169(b), Ambient Air Quality Standards

All stationary sources are required to comply with the NAAQS to stay within increment allocations. Increment allocations are developed from computerized dispersion modeling. CS4 is subject to the NAAQS requirements.

Compliance Summary: If required, Great Lakes will provide an analysis of ambient air impacts using applicable air quality models as required by the Title V permits once the permit is issued. Therefore, CS4 is in compliance with the NAAQS requirements.

4. New Source Performance Standards (NSPS)

Cite: 40 CFR 60 Subpart GG, Standards of Performance for New Stationary Gas Turbines

According to 40 CFR 60.333(a), "The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour [10 MMBtu/hr]..." According to 40 CFR 60.333(b), "Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of the part..."

EU001 has a capacity of more than 10 MMBtu/hr of heat input, but was installed prior to the October 3, 1977 date of NSPS applicability. Therefore, EU001 is not subject to NSPS.

EU002 has a capacity of more than 10 MMBtu/hr of heat input, but was installed in 1993. Therefore, EU002 is subject to NSPS.

NO_X emission standard under NSPS: EU002 is subject to NO_X emission standards as calculated by 40 CFR 60.332(a)(2). The rule specifies the following formula be used to calculate the NO_X emission concentration limit:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section

Table 4.1 shows the information used to calculate the NSPS NO_X emission limitation for EU002.

Table 4.1
Allowable NO_X Emissions

Turbine Unit No.	Y, Actual Measured Heat Rate[3] (Btu/HP-hr)	Y, converted units (kJ/W-hr)[4]	F (NO_X % vol)	Calculated NO_X Emission Concentration (% by volume, 15% O2, dry)[5]
402	7777.73	11.001	0	0.0196

Fuel Nitrogen Testing Requirements: EPA policy does not require fuel nitrogen testing.

[3] The Actual Measured Heat Rate is the average of tests at maximum load performed in 1995 of the fleet of same-model turbines owned by ANR at the time. 7777.73 Btu/HP-hr = 140.89 MMbtu/hr heat input / 18,114.54 HP x 1,000,000 btu/MMbtu

[4] 11.001 kJ/W-hr = 7,777.73 Btu/HP-hr x 1054.8 J/Btu x 1 kJ/1000 J x 1.341 HP/kW x 1 kW/1000 W

[5] 0.0196 % NOx vol = (0.015 x 14.4 / 11.001) + 0

Sulfur Dioxide (SO_2) testing and fuel sulfur limitations under NSPS: Per 40 CFR 60.333(b), "...No owner or operator subject to the provisions of this section may burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8% by weight. ..." Great Lakes' Federal Energy Regulatory Commission (FERC) Gas Tariff, Second Revised Volume No. 1, limits the amount of sulfur that may be present in the natural gas in Great Lakes' pipeline system. The FERC tariff, enclosed as Appendix D provides that total sulfur within the natural gas cannot exceed 20 grains per hundred cubic feet of gas (grains/100 ft^3), or 0.064% by weight.

Previously, compliance has been demonstrated in accordance with federal NSPS requirements and a custom schedule approved by EPA on November 20, 1998.

With this permit renewal, Great Lakes' intends to demonstrate compliance with the sulfur limits using their current tariff sheet under 40 CFR 60.334(h)(3)(i):

> "(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:
>
> (i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less"

Table 4.2
Comparison of Unit Concentrations for Applicable Natural Gas Fuel Sulfur Concentrations

Source	Concentration grains/100 SCF	Concentration % by weight	Concentration ppm (m/m)
NSPS	248.1	0.8	8,000
Federal Tariff	20.0	0.0645	645
Actual Lab and OM-10 Analyzer Results	0.2	0.000645	6.45

Compliance Summary: EU002 is the only emission source at CS4 which is subject to NSPS. Stack testing has substantiated that the unit is in compliance with the NO_X standards presented above. Great Lakes is also in compliance with the sulfur standard because the gas quality characteristics of the current tariff sheet specify that the maximum total sulfur content is 20.0 grains/100 scf or less.

5. Acid Rain Requirements

Cite: 40 CFR 72 (42 USC 7651 to 7651o - 1990 Clean Air Act, as amended, Sections 401-416 by inclusion), Acid Rain Program General Provisions

Utilities and other facilities that combust fossil fuel (coal) and generate electricity for wholesale or retail sale may be subject to acid rain program requirements, including the requirements to hold an acid rain permit under 40 CFR 72. CS4 does not fall under this definition and is therefore not subject to the Acid Rain Requirements.

6. Accidental Releases

Cite: 40 CFR 68, Risk Management Programs for Chemical Accidental Release Prevention Requirements

Because CS4 does not produce, process, store or use any of the regulated toxic substances (listed in 40 CFR 68.130) in excess of the thresholds, CS4 is not subject to the Risk Management Programs for Chemical Accidental Release Prevention Requirements.

II. ADDITIONAL STATE AIR POLLUTION CONTROL REQUIREMENT

7. General Construction and Operating Permit Requirements

Cite: Minn. Rules Part 7007.0200, Sources Required or Allowed to Obtain a Part 70 Permit

Per Minn. Rules Part 7007.0200 Subpart 2, any major stationary source of air pollutants, as defined in section 302 of the act (General Provisions; Definitions), that directly emits or has the potential to emit, 100 tons per year or more of any air pollutant must obtain a permit under this part.

CS4 directly and potentially emits concentrations of air pollutants in excess of 100 tons per year.

Compliance Summary: This application satisfies the requirements of Minn. Rules Part 7007.0200 Subpart 2, Sources Required or Allowed to Obtain a Part 70 Permit.

8. Control of Pollutant Emissions

Cite: Minn. Rules Part 7011.0105, Visible Emission Restrictions for Existing Facilities

Minn. Rules Part 7011 .0105 states, "No owner or operator of an existing emission facility to which parts 7011.0100 to 7011 .0115 are applicable shall cause to be discharged into the atmosphere from the facility any gases which exhibit greater than 20 percent opacity; except that a maximum of 40 percent opacity shall be permissible for four minutes in any 60-minute period."

Due to the nature of natural gas combustion emissions, little or no opacity is generated. Emission standards for visible air contaminants have not been defined for the stationary natural gas turbines in any other rule.

Compliance Summary: The MPCA has not requested testing for opacity emissions. Therefore, CS4 is in compliance with the visible emissions rule.

Cite: Minn. Rules Part 7011.0150, Preventing Particulate Matter from Becoming Airborne

Minn. Rules Part 7001.0150 states: "No person shall cause or permit the handling, use, transporting, or storage of any material...or permit a building or its appurtenances or a road, or a driveway, or an open area to be constructed, used, repaired, or demolished without applying all such reasonable measures as may be required to prevent particulate matter from becoming airborne."

Compliance Summary: Great Lakes has written a Fugitive Emission Control Plan, which was approved by the MPCA and has been implemented at CS4. Therefore, CS4 is in compliance with the particulate requirements.

Cite: Minn. Rules Part 7011.2300, Standards of Performance for Stationary Internal Combustion Engines

Minn. Rules Part 7011.2300 Subpart 1, Visible Air Contaminants states: "No owner or operator of any stationary internal combustion engine shall cause or permit the emission of visible air contaminants from the engine in excess of 20 percent opacity once operating temperatures have been obtained."

The standby electrical generator is the only emission unit at CS4 that meets the definition of stationary internal combustion engine.

Compliance Summary: The MPCA has not required testing for opacity emissions. Therefore, CS4 is in compliance with the visible air contaminants section of the Minnesota standards of performance for stationary internal combustion engines.

Cite: Minn. Rules Part 7030.0040, Noise Standards

Standards describing the limiting levels of sound established on the basis of present knowledge for the preservation of public health and welfare are listed in Minn. Rules Part 7030.0040. The State may request testing of sources.

Compliance Summary: The MPCA has not requested CS4 to do noise testing. Therefore, CS4 is in compliance with the Noise Standards.

9. Compliance with Air Emission Inventory Requirements

Cite: Minn. Rules Part 7019.3000, Emission Inventory

Minn. Rules Part 7019.3000: All owners and operators of stationary sources with potential emissions of more than 25 tons per year of a regulated pollutant shall submit an annual emission inventory report to the MPCA, in a format specified by the commissioner, relating to carbon monoxide and all regulated pollutants as defined in Minn. Rules Part 7002.005, Subpart 4. The report shall be submitted on or before April 1 of the year following the year being reported.

CS4 is a stationary source with actual and potential emissions of regulated pollutants in excess of 25 tons per year.

Compliance Summary: Great Lakes has provided an emission inventory to the MPCA for every year since 1992. CS4 is in compliance with the Emission Inventory rules.

10. Reporting, Recordkeeping, Testing, and Inspection Requirements

Cite: Minn. Rules Part 7007.0800, Compliance Plan/Certification Reports

"The permit shall require submittal of an annual compliance certification by January 31 of each year to the agency. In the case of part 70 permits, compliance certifications shall be submitted to the administrator as well as the agency; unless the administrator agrees that the submittals are not necessary."

Compliance Summary: Appendix H of this Title V application, Regulatory Review and Compliance Plan, constitutes the compliance plan for this Title V application. Additionally, Great Lakes does submit an annual compliance report to the MPCA. Therefore, CS4 is in compliance with the Compliance Plan/Certification Reports requirements.

Cite: Minn. Rules Part 7017, Monitoring and Testing Requirements

Below are is the requirement that deals with the issue of performance testing.

> Performance Test General Requirements – Per Minn. Rule Part 7017.2020; "... the owner or operator of an emission facility shall arrange to conduct a performance test at any emission facility at the times required by an applicable requirement or compliance document and at additional times if the commissioner requests a performance test..."

Compliance Summary: Great Lakes has submitted all testing notifications, test plans, and test results in a timely manner. Great Lakes will conduct compliance testing as requested by the commissioner. Therefore, CS4 is in compliance with the monitoring and testing requirements of Minn. Rules Chapter 7017.

Appendix I Insignificant Activities

- Table 1 - Potential Emissions from Insignificant Activities

Minnesota Pollution Control Agency

520 Lafayette Road North
St. Paul, MN 55155-4194

IA-01

Insignificant Activities Required To Be Listed

Air Quality Permit Program

1) AQ Facility ID No.: N/A

2) Facility Name: Deer River Compressor Station No. 4

3) Check and describe insignificant activities:

	Rule Citation	Description of Activities at the Facility
☒	7007.1300, subp. 3(A)	Three (3) Reznor space heaters, natural gas-fired, < 0.2 MMbtu/hr each
☐	7007.1300, subp. 3(B)(1)	
☒	7007.1300, subp. 3(B)(2)	Residential hot water heater, natural gas-fired, 0.033 MMbtu/hr
☐	7007.1300, subp. 3(C)	
☐	7007.1300, subp. 3(D)	
☐	7007.1300, subp. 3(E)(1)	
☒	7007.1300, subp. 3(E)(2)	One diesel aboveground storage tank with dispensing nozzle, approximately 400 gallon
☐	7007.1300, subp. 3(F)	
☐	7007.1300, subp. 3(G)	
☐	7007.1300, subp. 3(H)(1)	
☐	7007.1300, subp. 3(H)(2)	
☒	7007.1300, subp. 3(H)(3)	Arc welding torches (3) and oxy-acetylene welding (1) of approximately 20 hr/yr.
☐	7007.1300, subp. 3(H)(4)	
☐	7007.1300, subp. 3(H)(5)	
☐	7007.1300, subp. 3(H)(6)	
☐	7007.1300, subp. 3(H)(7)	

	Rule Citation	Description of Activities at the Facility
☒	7007.1300, subp. 3(I)	Boiler, natural gas-fired, 5.2 MMBTU/hr capacity.
		Gasoline-powered portable electrical generator, Honda GX100 engine, 2.8 HP
		Gasoline-powered portable water pump, Honda GX120 engine, 3.5 HP
☐	7007.1300, subp. 3(J)	
☐	7007.1300, subp. 3(K)	
☐	7007.1300, subp. 4	
☒	7008.4100	Parts cleaning bin using approximately 30 gallons/year of VOC-containing parts cleaning fluid.
☒	7008.4110	Abrasive cleaning operation with hood that filters air and exhausts indoors.

Form IA-01 Instructions

Four tables of insignificant activities are provided below.

- **Table IA-01.1, Insignificant Activities Not Required to be Listed**, specifies those activities that **do not** need to be included in your permit application.
- **Table IA-01.2, Insignificant Activities Required to be Listed, and Table IA-01.4, Conditionally Insignificant Activities**, specify those activities that must be included in your application, on the **IA-01** form.
- **Table IA-01.3, Insignificant Activities Required to be Listed for Part 70 Sources**, specifies insignificant activities which are required to be listed in part 70 permit applications but do not qualify as insignificant activities for state permits.
- If your facility has a Plantwide Applicability Limit (PAL), or you are applying for a PAL, all activities from Tables IA-01.2, 3, and 4 that emit the PAL pollutant no longer qualify as Insignificant Activities and must be included in your permit application as emitting equipment using the appropriate forms (e.g., GI-04, GI-05B, GI-05C, GI-07, EC forms, CD-01, etc.).
- Any activity that requires a permit under 40 CFR § 52.21 (e.g., it is included in a previous Best Available Control Technology [BACT] determination or is subject to conditions to avoid New Source Review), no longer qualifies as Insignificant Activity and must be included in your permit application on the appropriate forms (e.g., GI-04, GI-05B, GI-05C, GI-07, EC forms, CD-01, etc.).
- It is possible that activities listed on this form may be included in your permit with applicable requirements and associated periodic monitoring.

1) **AQ Facility ID No.** -- Fill in your Air Quality Facility ID Number as listed on Form GI-01, item 1a.
2) **Facility Name** -- Enter your facility name as listed on Form GI-01, item 2.
3) **Description of Activities** - Check the boxes for the insignificant activities listed in Tables IA-01.2, IA-01.3, and IA-01.4 that take place at your stationary source. For each checked activity, provide a brief description of the activity taking place at your stationary source. Fill out a separate row for each listed activity. Provide enough detail in your description so it is clear how the emission unit(s) at your source meet the definition of the insignificant activity. For example, insignificant activity subpart 3(E)(1) corresponds to gasoline storage tanks with a combined total tankage capacity of not more than 10,000 gallons. If you have gasoline storage tanks that meet this definition, indicate the total capacity of your tanks to show that it is under 10,000 gallons. If you run out of room on the table, make additional copies of the form.

Table IA-01.1 Insignificant Activities Not Required To Be Listed:

The activities described below are **not required to be listed** in your permit application under Minn. R. 7007.0500, subp. 2(C)(2).

Subp. 2(A)	Fuel use: 1. production of hot water for on-site personal use not related to any industrial process; 2. fuel use related to food preparation by a restaurant or cafeteria; and 3. fuel burning equipment with a capacity less than 30,000 Btu/hour, but only if the combined total capacity of all fuel burning equipment at the stationary source with a capacity less 30,000 Btu per hour is less than or equal to 500,000 Btu/hour.
Subp. 2(B)	Plant upkeep: 1. routine housekeeping or plant upkeep activities not associated with primary production processes at the stationary source, such as: painting buildings, retarring roofs, paving parking lots, but excluding use of spray paint equipment. 2. routine maintenance of buildings, grounds, and equipment; 3. use of vacuum cleaning systems and equipment for portable steam cleaning; 4. clerical activities such as operating copy machines and document printers, except operation of such units on a commercial basis; 5. janitorial activities; and 6. sampling connections used exclusively to withdraw materials for laboratory analysis and testing.
Subp. 2(C)	Fabrication operations: 1. equipment used for the inspection of metal products; 2. equipment used exclusively for forging, pressing, drawing, spinning, or extruding cold metals; 3. equipment used exclusively to mill or grind coatings and molding compounds where all materials charged are in paste form; and 4. mixers, blenders, roll mills, or calendars for rubber or plastics for which no materials in powder form are added and in which no organic solvents, diluents, or thinners are used.
Subp. 2(D)	Processing operations: 1. closed tumblers used for cleaning or deburring metal products without abrasive blasting; 2. equipment for washing or drying fabricated glass or metal products, if no Volatile Organic Compounds (VOCs) are used in the process, and no gas, oil, or solid fuel is burned; 3. equipment venting particulate matter (PM) or particulate matter less than 10 microns (PM-10) inside a building provided that emissions from the equipment: (a) are vented inside of the building 100% of the time; and (b) do not use air filtering systems used to control indoor air emissions; and 4. blast cleaning operations using suspension of abrasive in water.
Subp. 2(E)	Storage tanks: 1. pressurized storage tanks for anhydrous ammonia, liquid petroleum gas (LPG), liquid natural gas (LNG), or natural gas; 2. storage tanks holding lubricating oils; 3. above and below ground fuel oil storage tanks with a combined total tankage capacity of less than 100,000 gallons; and 4. gasoline storage tanks with a combined total tankage capacity of less than 2,000 gallons.
Subp. 2(F)	Drain, waste, and vent piping: 1. stacks or vents to prevent escape of sewer gases through plumbing traps, not including stacks and vents associated with processing at wastewater treatment plants; 2. sewer maintenance access covers and shafts; 3. sludge and septage landspreading sites; 4. sludge loadout pumping operations for publicly owned treatment works with a design flow less than 5,000,000 gallons per day; and 5. odor control systems on components of publicly owned treatment works collection systems.
Subp. 2(G)	Residential activities: typical emissions from residential structures, not including the following: 1. fuel burning equipment with a total capacity of 500,000 Btu/hour or greater; and 2. emergency backup generators.

Subp. 2(H)	Recreational activities: use of the following for recreational purposes: 1. fireplaces; 2. barbecue pits and cookers; and 3. kerosene fuel use.
Subp. 2(I)	Health care activities: activities and equipment directly associated with the diagnosis, care, and treatment of patients in medical or veterinary facilities or offices, not including support activities such as power plants, heating plants, emergency generators, incinerators, or other units affected by applicable requirements as defined in Minn. R. 7007.0100, subp. 7.
Subp. 2(J)	Miscellaneous: 1. safety devices, such as fire extinguishers, if associated with a permitted emission source, but not including sources of continuous emissions; 2. flares to indicate danger to the public; 3. vehicle exhaust emissions from the operation of mobile sources at a stationary source; 4. purging of natural gas lines; 5. natural draft hoods, natural draft ventilation, comfort air conditioning, or comfort ventilating systems not designed or used to remove air contaminants generated by, or released from specific units of equipment; 6. funeral home embalming processes and associated ventilation systems; and 7. use of consumer products, including hazardous substances as that term is defined in the Federal Hazardous Substances Act, where the product is used at academic and health care institutions in the same manner as normal consumer use.
Subp. 2(K)	Demonstration project conducted by a teaching institution, where the sole purpose of a demonstration project is to provide an actual functional example of a process unit operation to the students or other interested persons, where actual operating hours of each emissions unit must not exceed a total of 350 hours in a calendar year and where the emissions unit is not used to dispose of waste materials.

Table IA-01.2 Insignificant Activities Required To Be Listed:

The activities described below must be listed in your permit application. The Minnesota Pollution Control Agency (MPCA) may require you to submit calculations of emissions from these emission units and may choose to include them in your permit. You must calculate emissions from these emission units and include them in your permit application on the appropriate forms (e.g., GI-04, GI-05B, GI-05C, GI-07, EC forms, CD-01, etc.) if any of the following are true:

- the emissions units are subject to additional requirements under Section 114(a)(3) of the Clean Air Act;
- the emissions units are subject to Hazardous Air Pollutant requirements under Section 112 of the Clean Air Act;
- the emissions units are part of a Title I modification;
- if accounted for, the emissions units make the stationary source subject to a part 70 permit; or
- if the emissions units meet the criteria listed at the beginning of these instructions (e.g., if they are included in a PAL).

Subp. 3(A)	Fuel use: space heaters fueled by, kerosene, natural gas, or propane. A space heater is a heating unit that is not connected to piping or ducting to distribute the heat.
Subp. 3(B)	Furnaces, boilers, and incinerators: 1. infrared electric ovens; and 2. fuel burning equipment with a capacity less than 500,000 Btu/hour but only if the total combined capacity of all fuel burning equipment at the stationary source with a capacity less than 500,000 Btu per hour is less than or equal to 2,000,000 Btu/hour.
Subp. 3(C)	Fabrication operations: equipment used exclusively for forging, pressing, drawing, spinning, or extruding hot metals.
Subp. 3(D)	Processing operations: open tumblers with a batch capacity of 1,000 pounds or less.
Subp. 3(E)	Storage tanks: 1. gasoline storage tanks with a combined total tankage capacity of not more than 10,000 gallons; and 2. non-hazardous air pollutant VOC storage tanks with a combined total tankage capacity of not more than 10,000 gallons of non-hazardous air pollutant VOCs and with a vapor pressure of not more than 1.0 psia at 60 degrees Fahrenheit.
Subp. 3(F)	Cleaning operations: commercial laundries, not including dry cleaners and industrial launderers.

Subp. 3(G)	Emissions from a laboratory, as defined in this item. "Laboratory" means a place or activity devoted to experimental study or teaching in any science, or to the testing and analysis of drugs, chemicals, chemical compounds or other substances, or similar activities, provided that the activities described in this sentence are conducted on a laboratory scale. Activities are conducted on a laboratory scale if the containers used for reactions, transfers, and other handling of substances are designed to be easily and safely manipulated by one person. If a facility manufactures or produces products for profit in any quantity, it may not be considered to be a laboratory under this item. Support activities necessary to the operation of the laboratory are considered to be part of the laboratory. Support activities do not include the provision of power to the laboratory from sources that provide power to multiple projects or from sources which would otherwise require permitting, such as boilers that provide power to an entire facility.
Subp. 3(H)	Miscellaneous: 1. equipment used exclusively for packaging lubricants or grease; 2. equipment used for hydraulic or hydrostatic testing; 3. brazing, soldering or welding equipment; 4. blueprint copiers and photographic processes; 5. equipment used exclusively for melting or application of wax; 6. nonasbestos equipment used exclusively for bonding lining to brake shoes; and 7. cleaning operations: alkaline/phosphate cleaners and associated cleaners and associated burners.
Subp. 3(I)	Individual emissions units at a stationary source, each of which have a potential to emit the following pollutants in amounts less than: 1. 4,000 lbs/year of carbon monoxide; and 2. 2,000 lbs/year each of nitrogen oxide, sulfur dioxide, particulate matter, particulate matter less than ten microns, volatile organic compounds (including hazardous air pollutant-containing VOC), and ozone.
Subp. 3(J)	Fugitive Emissions from unpaved roads and parking lots, except from a stationary source applying for an Option D registration permit under Minn. R. 7007.1130.
Subp. 3(K)	Infrequent use of spray paint equipment for routine housekeeping or plant upkeep activities not associated with primary production processes at the stationary source, such as spray painting of buildings, machinery, vehicles, and other supporting equipment.

Table IA-01.3 Insignificant Activities Required To Be Listed for Part 70 Sources

If you are applying for a part 70 permit, activities that are not listed in Table IA-01.1, but have potential emissions less than those in this table may be included as insignificant activities to be listed in your part 70 permit application. If you are applying for any type of state permit (including an individual state permit, a state general permit, or a state registration permit) or an amendment to a state permit, this table does not apply.

The MPCA may require you to submit calculations of emissions from these emission units and may choose to include them in your permit. You must calculate emissions of these activities in accordance with the criteria provided at the beginning of Table IA-01.2. These activities must be included in your permit application as emitting equipment using the appropriate forms if they meet any of those criteria.

Subp. 4	Individual emissions units at a stationary source, each of which have potential emissions less than the following limits: A. 5.7 lbs/hr of carbon monoxide; B. 2.28 lbs/hr or actual emissions of one ton per year for nitrogen oxides, sulfur dioxide, particulate matter, particulate matter less than ten microns, and volatile organic compounds; and C. for hazardous air pollutants, emissions units with: 1. potential emissions of 25 percent or less of the hazardous air pollutant thresholds listed in Minn. R 7007.1300, subp. 5; or 2. combined HAP actual emissions of one ton per year unless the emissions unit emits one or more of the following HAPs: carbon tetrachloride; 1,2-dibromo-3-chloropropane; ethylene dibromide; hexachlorobenzene; polycyclic organic matter; antimony compounds; arsenic compounds, including inorganic arsine; cadmium compounds; chromium compounds; lead compounds; manganese compounds; mercury compounds; nickel compounds; selenium compounds; 2,3,7,8-tetrachlorodibenzo-p-dioxin; or dibenzofuran. If the emissions unit emits one or more of the HAPs listed in this subitem, the emissions unit is not an insignificant activity under this subitem.

Table IA-01.4 Conditionally Insignificant Activities:

The activities described below must be listed in your permit application. The MPCA may require you to submit calculations of emissions from these emission units. You must calculate emissions from these emission units and include them in your permit application on the appropriate forms (e.g., GI-04, GI-05B, GI-05C, GI-07, EC forms, CD-01, etc.) if any of the following are true:

- the emissions units are subject to additional requirements under Section 114(a)(3) of the Clean Air Act;
- the emissions units are subject to Hazardous Air Pollutant requirements under Section 112 of the Clean Air Act;
- the emissions units are part of a Title I modification;
- if accounted for, the emissions units make the stationary source subject to a part 70 permit; or
- if the emissions units meet the criteria listed at the beginning of these instructions (e.g., if they are included in a PAL).

7008.4100	Total VOC Usage at the stationary source less than 200 gallons or 2000 pounds in each calendar year. See Minn. R. 7008.4100 for recordkeeping and calculation requirements for this activity.
7008.4110	Emissions from equipment venting particulate matter (PM) or particulate matter less than 10 microns (PM-10) inside a building, provided that emissions from the equipment are: (A) filtered through an air cleaning system; and (B) vented inside of the building 100% of the time.

Appendix I - Table 1 - Potential Emissions From Insignificant Activities

Subp. 4. Insignificant activities required to be listed in a part 70 application. If a facility is applying for a part 70 permit, emissions units with emissions less than all the following limits but not included in subpart 2 must be listed in a part 70 permit application:

A. potential emissions of 5.7 pounds per hour or actual emissions of two tons per year of carbon monoxide;

B. potential emissions of 2.28 pounds per hour or actual emissions of one ton per year for particular matter, particulate matter less than ten microns, nitrogen oxide, sulfur dioxide, and VOCs: and

These calculations should be provided upon request of EPA.

Equipment Information				
Facility:	Deer River CS #4	Deer River CS #4	Deer River CS #4	Deer River CS #4
Equipment Type:	Boiler	Engine (generator)	Engine (water pump)	Engine (hydraulic pump)
Make:	Kewanee	Honda	Honda	Deutz
Model Number:	L3W125-G	GX100 (EU2000i)	GX120	MD191
Installation date:	1993	Portable	Portable	Portable
Fuel Burned:	Natural gas	Gasoline	Gasoline	Diesel
Assumptions:				
Maximum Firing Rate (MMBtu/hr):	5.23			
Engine Rated Capacity, (hp):		2.80	3.50	17.70
PTE Hours of Operation:	8,760	8,760	8,760	8,760
Calculated Max. Annual Fuel Use (MMscf/year):	44.92	0.00	0.00	0.00
Calculated Max. Hourly Fuel Use (MMscf/hour):	0.005	0.000	0.000	0.000
Brake-Specific Fuel Consumption (Btu/hp-hr):		7,000	7,000	7,000
Fuel Heat Content (Btu/scf):	1,020	1,020	1,020	1,020

Criteria Pollutant Emission Factors

Criteria Pollutant	AP-42 Emission Factor (lb/MMscf)	AP-42 Emission Factor (lb/hp-hr)	AP-42 Emission Factor (lb/hp-hr)	AP-42 Emission Factor (lb/hp-hr)
NOx	100	0.011	0.011	0.03
VOC	5.5	0.021591	0.021591	0.0025141
SO2	0.6	0.000591	0.000591	0.00205
PM10	7.6	0.000721	0.000721	0.00220
CO	84	0.439	0.439	0.00668
Source of Emission Factors - AP-42 Table Number	1.4-1 and 1.4-2	3.3-1	3.3-1	3.3-1

Potential Emissions - Criteria Pollutants

Criteria Pollutant	PTE Hourly Emissions (lb/hr)	PTE Hourly Emissions (lb/hr)	PTE Hourly Emissions (lb/hr)	PTE Hourly Emissions (lb/hr)	Insig. Threshold (lb/hr)
NOx	0.51	0.03	0.04	0.55	2.28
VOC	0.03	0.06	0.08	0.04	2.28
SO2	0.00	0.00	0.00	0.04	2.28
PM10	0.04	0.00	0.00	0.04	2.28
CO	0.43	1.23	1.54	0.12	5.70

C. for hazardous air pollutants, emissions units with:

(1) potential emissions of 25 percent or less of the hazardous air pollutant thresholds listed in subpart 5: or

(2) combined HAP actual emissions of one ton per year unless the emissions unit emits one or more of the following HAPs: carbon tetrachloride; 1,2-dibromo-3-chloropropane; ethylene dibromide; hexachlorobenzene; polycyclic organic matter; antimony compounds; arsenic compounds, including inorganic arsine; cadmium compounds; chromium compounds, lead compounds; manganese compounds; mercury compounds; nickel compounds; selenium compounds; 2,3,7,8-tetrachlorodibenzo-p-dioxin; or dibenzofuran. If the emissions unit emits one or more of the HAPs listed in this subitem, the emissions unit is not an insignificant activity under this subitem.

Calculation of emissions from the emissions units listed in this subpart shall be provided if required by the agency under part 7007.0500, subpart 2, item C, subitem (2). If emissions units listed under this subpart are subject to additional requirements under section 114(a)(3) of the act (Monitoring Requirements) or section 112 of the act (Hazardous Air Pollutants), or are part of a title I modification, or if accounted for, make a stationary source subject to a part 70 permit emissions from the emissions units must be calculated in the permit application. If the applicant is applying for a state permit or an amendment to a state permit, this subpart does not apply.

HAP Emission Factors

Hazardous Air Pollutant (HAP)	AP-42 Emission Factor (lb/MMscf)	AP-42 Emission Factor (lb/hp-hr)	AP-42 Emission Factor (lb/hp-hr)	AP-42 Emission Factor (lb/MMbtu)
1,3-Butadiene	2.40E-05			3.91E-05
2-Methylnaphthalene	2.40E-05			
3-Methylchloranthrene	1.80E-06			
7,12-Dimethylbenz(a)anthracene	1.60E-05			
Acenaphthene	1.80E-06			
Acenaphthylene	1.80E-06			
Acrolein				9.25E-05
Acetaldehyde				7.67E-04
Anthracene	2.40E-06			
Arsenic	2.00E-04			
Benz(a)anthracene	1.80E-06			
Benzene	2.10E-03			9.33E-04
Benzo(a)pyrene	1.20E-06			
Benzo(b)fluoranthene	1.80E-06			
Benzo(g,h,i)perylene	1.20E-06			
Benzo(k)fluoranthene	1.80E-06			
Beryllium	1.20E-05			
Cadmium	1.10E-03			
Chromium	1.40E-03			
Chrysene	1.80E-06			
Cobalt	8.40E-05			
Dibenzo(a,h)anthracene	1.20E-06			
Dichlorobenzene	1.20E-03			
Fluoranthene	3.00E-06			
Fluorene	2.80E-06			
Formaldehyde	7.50E-02			1.18E-03
Indeno(1,2,3-cd)pyrene	1.80E-06			
Lead	5.00E-04			
Manganese	3.80E-04			
Mercury	2.60E-04			
Naphthalene	6.10E-04			
n-Hexane	1.80E+00			
Nickel	2.10E-03			
Phenanthrene	1.70E-05			
Pyrene	5.00E-06			
Selenium	2.40E-05			
Toluene	3.40E-03			4.09E-04
Total PAH				1.68E-04
Xylenes				2.85E-04
Source of Emission Factors - AP-42 Table Number	1.4-3 and 1.4-4			3.3-2

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	PTE Hourly Emissions (tpy)	PTE Hourly Emissions (tpy) (see Note A)	PTE Hourly Emissions (tpy) (see Note A)	PTE Hourly Emissions (tpy)	Insig. Threshold 25% of De Minimis (tpy)	De Minimis Level (tpy)
1,3-Butadiene	0.0000			0.0000	0.0175	0.07
2-Methylnaphthalene	0.0000			0.0000	0.0025	0.01
3-Methylchloranthrene	0.0000			0.0000	0.0025	0.01
7,12-Dimethylbenz(a)anthracene	0.0000			0.0000	0.0025	0.01
Acenaphthene	0.0000			0.0000	0.0025	0.01
Acenaphthylene	0.0000			0.0000	0.0025	0.01
Acetaldehyde	0.00			0.00	2.25	9
Acrolein	0.00			0.00	0.01	0.04
Anthracene	0.0000			0.0000	0.0025	0.01
Arsenic	0.00000			0.00000	0.00125	0.005
Benz(a)anthracene	0.0000			0.0000	0.0025	0.01
Benzene	0.0			0.0	0.5	2
Benzo(a)pyrene	0.0000			0.0000	0.0025	0.01
Benzo(b)fluoranthene	0.0000			0.0000	0.0025	0.01
Benzo(g,h,i)perylene	0.0000			0.0000	0.0025	0.01
Benzo(k)fluoranthene	0.0000			0.0000	0.0025	0.01
Beryllium	0.000000			0.000000	0.000005	0.00002
Cadmium	0.0000			0.0000	0.0025	0.01
Chromium	0.00			0.00	1.25	5
Chrysene	0.0000			0.0000	0.0025	0.01
Cobalt	0.000			0.000	0.025	0.1
Dibenzo(a,h)anthracene	0.0000			0.0000	0.0025	0.01
Dichlorobenzene	0.00			0.00	0.75	3
Fluoranthene	0.0000			0.0000	0.0025	0.01
Fluorene	0.0000			0.0000	0.0025	0.01
Formaldehyde	0.0			0.0	0.5	2
Indeno(1,2,3-c,d)pyrene	0.0000			0.0000	0.0025	0.01
Lead	0.0000			0.0000	0.0025	0.01
Manganese	0.0			0.0	0.2	0.8
Mercury	0.0000			0.0000	0.0025	0.01
Naphthalene	0.0			0.0	2.5	10
n-Hexane	0.0			0.0	2.5	10
Nickel	0.00			0.00	0.25	1
Phenanthrene	0.0000			0.0000	0.0025	0.01
Pyrene	0.0000			0.0000	0.0025	0.01
Selenium	0.000			0.000	0.025	0.1
Toluene	0.0			0.0	2.5	10
PAH	0.0000			0.0001	0.0025	0.01
Xylene	0.0			0.0	2.5	10
Total HAP PTE (tpy)	0.04	0.0000	0.0000	0.0021		

IERA

Table 15-2. Liquid-phase and Vapor-phase HAP Speciation of Gasoline

HAP Component	Weight Percent in Liquid-Phase[a]	Weight Percent in Vapor-Phase[b]
Benzene	1.8	0.6
Cumene	0.5	0.02
Ethylbenzene	1.4	0.04
Hexane (n-hexane)	1	0.5
Methyl tert-butyl ether	4.5	4.6
Naphthalene	0.3	Negligible
Toluene	7	0.7
2,2,4-Trimethylpentane	4	0.7
Xylenes (mixed isomers)	7	0.2

[a] With the exception of naphthalene, the liquid-phase speciation is based on "typical" values obtained from Table 3 of API's Manual of Petroleum Measurement Standards, Chapter 19.4. The naphthalene liquid-phase percentage was obtained by averaging the sample results found in the draft version of EPA's report entitled "Technical Support Document for Development of a Comparable Fuel Exemption."

[b] The vapor-phase speciation was calculated using the liquid-phase speciation values and the procedures found in Section 7.1.4 of AP-42. Specific data (e.g., molecular weights, vapor pressures, etc.) used in the calculations can be found in Appendix E.

AP-42

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01) Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)
NO_x	0.011	1.63
CO	0.439	62.7
SO_x	5.91 E-04	0.084
PM-10[b]	7.21 E-04	0.10
CO_2[c]	1.08	154
Aldehydes	4.85 E-04	0.07
TOC		
Exhaust	0.015	2.10
Evaporative	6.61 E-04	0.09
Crankcase	4.85 E-03	0.69
Refueling	1.08 E-03	0.15

Note A
HAP Emissions factors are not readily available for gasoline engines. If one assumes all HAPs are coming from evaporative losses and incomplete combustion of fuel, and would therefore be less than total VOC, one can compare total VOC TPY to the 25% of de minimis threshold for each speciated HAP. The total VOC TPY is 0.33 TPY for the largest engine.
The lowest threshold that must be met is 0.5 TPY Benzene.
Note that this logic does not account for any HAP products of combustion.

Appendix J Emission Factors from Emissions Test Report

Emission Factors to be used for MAERS reporting for engines

Emission Unit	NO_X (lb/MMscf)	CO (lb/MMscf)	VOC (lb/MMscf)	PM (lb/MMscf)	SO_2 (lb/MMscf)
EU001	209.100	502.860	2.142	6.732	3.468
EU002	453.900	9.180	2.142	6.732	3.468

Source of Emission Factor

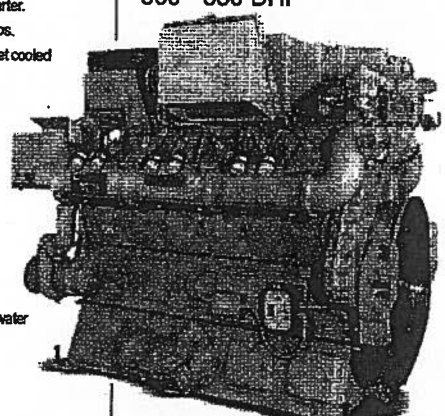
	EU001	EU002
NO_X	March 29, 2005 stack test. Stack test report submitted to EPA May 11, 2005.	March 30, 2005 stack test. Stack test report submitted to EPA May 11, 2005.
CO	March 29, 2005 stack test. Stack test report submitted to EPA May 11, 2005.	March 30, 2005 stack test. Stack test report submitted to EPA May 11, 2005.
VOC	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0021 lb/MMBtu)(1020 MMBtu/MMCF)= 2.142 lb/MMCF	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0021 lb/MMBtu)(1020 MMBtu/MMCF)= 2.142 lb/MMCF
PM	PM Total from April 2000 AP-42, Table 3.1-2a, Supplement F. (0.0066 lb/MMBtu)(1020 MMBtu/MMCF) = 6.732 lb/MMCF.	PM Total from April 2000 AP-42, Table 3.1-2a, Supplement F. (0.0066 lb/MMBtu)(1020 MMBtu/MMCF) = 6.732 lb/MMCF.
SO_2	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0034 lb/MMBtu)(1020 MMBtu/MMCF)= 3.468 lb/MMCF	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0034 lb/MMBtu)(1020 MMBtu/MMCF)= 3.468 lb/MMCF

Appendix K Waukesha Generator Specification Sheet

Waukesha VGF

L36GL

VGF™ Series Gas Engine
500 - 880 BHP



Engine shown with options.

Model L36GL Turbocharged and Intercooled, Lean Combustion, Twelve Cylinder, Four-Cycle Gas Engine

BASE ENGINE

CONNECTING RODS – Drop forged alloy steel, angle split, serrated joint, oil jet piston pin lubrication.

CRANKCASE – Alloy cast iron, fully ribbed, integral with cylinder frame.

CRANKSHAFT – Drop forged alloy steel, dynamically balanced and fully counterweighted. Viscous vibration dampener.

CYLINDERS – Removable wet type liners of centrifugally cast alloy iron.

CYLINDER HEADS – Twelve interchangeable, valve-in-head type, with two hard faced intake and two hard faced exhaust valves per cylinder. Replaceable intake and exhaust valve seats. Mechanical valve lifters with pivoted roller followers.

FLYWHEEL – With 165 tooth ring gear (for Delco electric and I-R air/gas starters). Flywheel machined to accept SAE 620D-21, 21" (533 mm) diameter clutch, or SAE J927B-210 flywheel converter.

FLYWHEEL HOUSING – SAE #00, nodular iron housing. Provision for two magnetic pickups.

PISTONS – Aluminum alloy, three ring, with patented high turbulence combustion bowl. Oil jet cooled with full floating piston pin. 11:1 compression ratio pistons.

STANDARD ACCESSORIES

AIR CLEANER – Dual two stage, dry panel type with rain shield and service indicator. Engine mounted.

BARRING DEVICE – Manual.

BREATHER – Crankcase, open type.

CARBURETOR – Two natural gas Impco 600 Varifuel downdraft.

CONTROLS – Local shutdown switch, engine mounted.

COOLING SYSTEM – Jacket water: gear driven jacket water pump, thermostatically controlled, full flow bypass type with nominal 180° F (82° C) outlet temperature. 4" ANSI flange connection. Auxiliary water: thermostatically controlled, gear driven pump supplies water to intercooler and oil cooler circuit. 2" special companion flanges supplied.

EXHAUST SYSTEM – Water cooled exhaust manifolds. Single outlet flange for ANSI 10" 125# flange.

GOVERNOR – Woodward PSG hydraulic.

IGNITION – Waukesha Custom Engine Control electronic ignition system with coils, cables and spark plugs. Non-shielded. 24V DC power required.

INTERCOOLER – Two pass, fin and tube, air-to-water.

LIFTING EYES – For engine only.

LUBRICATION SYSTEM – Gear type pump, two replaceable element filters and industrial base type oil pan, 86 gallon (326 litres) capacity. Engine mounted shell and tube oil cooler, thermostatic valve for oil temperature control.

MOUNTING – Base type oil pan.

PAINT – Oilfield orange.

TURBOCHARGER – Two exhaust driven, dry type with wastegate. For 1400 – 1800 rpm applications.

WAUKESHA CUSTOM ENGINE CONTROL DETONATION SENSING MODULE (DSM) – Includes engine mounted detonation sensors, DSM, filter and wiring. Operation of DSM requires Waukesha CEC Ignition Module (IM), which is standard equipment. 24V DC power supply is required for IM and DSM. DSM meets CSA Class 1, Group D, Division 2, hazardous location requirements.

RECOMMENDED GENERATOR SET SPECIFICATION

BREATHER – Crankcase, closed.

GOVERNOR – Woodward EPG.

INSTRUMENT PANEL/ENGINE PROTECTION SHUTDOWNS – Engine mounted; includes high jacket water temperature and low oil pressure switchgages.

REGULATOR – Fisher model Y692, mounted. A fuel shutoff valve must be provided to positively stop gas flow to the engine for both normal and emergency shut down.

RECOMMENDED COMPRESSOR SPECIFICATION

INSTRUMENT PANEL/ENGINE PROTECTION SHUTDOWNS – Engine mounted; includes high jacket water temperature and low oil pressure switchgages. Also includes intake manifold pressure gauge.

REGULATOR – Fisher model Y692, mounted with mechanical fuel shutoff valve.

SPECIFICATIONS

Cylinders
V 12

Piston Displacement
2193 cu. in. (36 L)

Bore & Stroke
5.98" x 6.5"
(152 x 165 mm)

Compression Ratio
11:1

Jacket Water System Capacity
44 gal. (166 L)

Lube Oil Capacity
86 gal. (326 L)

Fuel Pressure Range
25 - 50 psi
(172 - 345 kPa)

Starting System
150 psi max. air/gas
24V DC electric

Dry Weight
11,200 lb. (5171 kg)

Cooling Water Flow at	1500 rpm	1800 rpm
Jacket Water gpm (l/m)	184 (697)	218 (825)
Aux. Water gpm (l/m)	52 (197)	62 (235)

ISO 9001 CERTIFIED

POWER RATINGS: L36GL VGF SERIES GAS ENGINES

Model	I.C. Water Inlet Temp.	C.R.	Bore & Stroke in. (mm)	Displ. cu. in. (litres)	Brake Horsepower 1200 rpm[1] I	1200 rpm[1] C	1400 rpm[1] I	1400 rpm[1] C	1500 rpm I	1500 rpm C	1600 rpm I	1600 rpm C	1800 rpm I	1800 rpm C
L36GL	130° F (54° C)	11:1	5.98 x 6.5 (152 x 165)	2193 (36)	585	530	685	620	735	670	780	710	880	800
L36GL*	130° F (54° C)	11:1	5.98 x 6.5 (152 x 165)	2193 (36)	550	500	640	580	690	625	735	665	825	750
L36GL***	130° F (54° C)	11:1	5.98 x 6.5 (152 x 165)	2193 (36)	—	585	—	685	—	735	—	780	—	880

[1] Low speed turbocharger required for operation form 1100 - 1600 rpm.

**These power ratings are for engines applied at elevated jacket water temperatures 210° - 265° F (99° - 129° C).*

****These power ratings require Price Book Code 1100, and are available continuously when applied per WKI™ power and timing curve S7090-14. It is permissible to operate at up to 5% overload for two hours in each 24 hour period.*

Rating Standard: All models; Ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and Tcra (clause 10.1) as specified limited ±10° F (±5° C). Ratings are also valid for SAE J1349, BS5514, DIN6271 and AP17B-11C standard atmospheric conditions.

Intermittent Power Rating: The highest load and speed which can be applied in variable speed mechanical system application only. Operation at this rating is limited to a maximum of 3500 hours per year.

ISO Standard Power/Continuous Power Rating: The highest load and speed which can be applied 24 hours a day, seven days a week, 365 days per year except for normal maintenance, it is permissible to operate the engine at up to 10% overload, or maximum load indicated by the intermittent rating, whichever is lower, for two hours in each 24 hour period.

Standby Power Rating: This rating applies to those systems used as a secondary source of electrical power. This rating is the output the system will produce continuously (no overload), 24 hours per day for the duration of the prime power source outage.

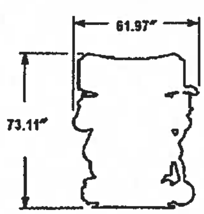
All natural gas engine ratings are based on a fuel of 900 Btu/ft³ (35.3 MJ/nm³) SLHV value, with a 91 WKI. For conditions or fuels other than standard, consult the Waukesha Engine Sales Engineering Department.

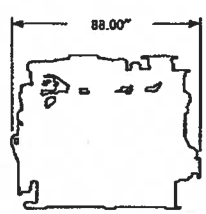
PERFORMANCE: L36GL VGF SERIES GAS ENGINES

	130° F (54° C) Intercooler Water Temp	1800 rpm	1500 rpm
Low NO_x Settings	Power	800	670
	BSFC (Btu/bhp-hr)	7720	7300
	NOx (grams/bhp-hr)	1.00	1.05
	CO (grams/bhp-hr)	1.30	1.30
	NMHC (grams/bhp-hr)	0.40	0.40
Low Fuel Consumption Settings	BSFC (Btu/bhp-hr)	6985	6765
	NOx (grams/bhp-hr)	2.00	2.33
	CO (grams/bhp-hr)	1.75	1.52
	NMHC (grams/bhp-hr)	0.75	0.65

NOTES:

1) Performance ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and Tcra limited to ± 10° F.
2) Fuel consumptions based on ISO 3046/1-1995 with a +5% tolerance for commercial quality natural gas having a 900 Btu/ft³ saturated low heat value.
3) Data based on standard conditions of 77° F (25° C) ambient temperature, 29.53 inches Hg (100kPa) barometric pressure, 30% relative humidity (0.3 inches Hg/1 kPa water vapor pressure).
4) Data will vary due to variations in site conditions. For conditions and/or fuels other than standard, consult the Waukesha Engine Sales Engineering Department.





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