Ohio Environmental Protection Agency

John R. Kasich, Governor
Mary Taylor, Lt. Governor
Craig W. Butler, Director

5/19/2016

Certified Mail

Yes	TOXIC REVIEW
Yes	PSD
No	SYNTHETIC MINOR TO AVOID MAJOR NSR
Yes	CEMS
Yes	MACT/GACT
Yes	NSPS
No	NESHAPS
No	NETTING
No	MAJOR NON-ATTAINMENT
Yes	MODELING SUBMITTED
Yes	MAJOR GHG
No	SYNTHETIC MINOR TO AVOID MAJOR GHG

Ms. Amy Frazier
South Field Energy LLC
31 Milk Street
Suite 1001
Boston, MA 02109

RE: DRAFT AIR POLLUTION PERMIT-TO-INSTALL
Facility ID: 0215132003
Permit Number: P0119495
Permit Type: Initial Installation
County: Columbiana

Dear Permit Holder:

A draft of the Ohio Administrative Code (OAC) Chapter 3745-31 Air Pollution Permit-to-Install for the referenced facility has been issued for the emissions unit(s) listed in the Authorization section of the enclosed draft permit. This draft action is not an authorization to begin construction or modification of your emissions unit(s). The purpose of this draft is to solicit public comments on the permit. A public notice will appear in the Ohio Environmental Protection Agency (EPA) Weekly Review and the local newspaper, The Morning Journal. A copy of the public notice and the draft permit are enclosed. This permit can be accessed electronically on the Division of Air Pollution Control (DAPC) Web page, www.epa.ohio.gov/dapc by clicking the "Search for Permits" link under the Permitting topic on the Programs tab. Comments will be accepted as a marked-up copy of the draft permit or in narrative format. Any comments must be sent to the following:

Andrew Hall
Permit Review/Development Section
Ohio EPA, DAPC
50 West Town Street, Suite 700
P.O. Box 1049
Columbus, Ohio 43216-1049

and

Ohio EPA DAPC, Northeast District Office
2110 East Aurora Road
Twinsburg, OH 44087

Comments and/or a request for a public hearing will be accepted within 30 days of the date the notice is published in the newspaper. You will be notified in writing if a public hearing is scheduled. A decision on issuing a final permit-to-install will be made after consideration of comments received and oral testimony if a public hearing is conducted.Any permit fee that will be due upon issuance of a final Permit-to-Install is indicated in the Authorization section. Please do not submit any payment now.If you have any questions, please contact Ohio EPA DAPC, Northeast District Office at (330)963-1200.

Sincerely,

Michael E. Hopkins

Michael E. Hopkins, P.E.
Assistant Chief, Permitting Section, DAPC

Cc: U.S. EPA Region 5 *-Via E-Mail Notification*
Ohio EPA-NEDO; Pennsylvania; West Virginia

Permit Strategy Write-Up

1. Check all that apply:

   Synthetic Minor Determination

   Netting Determination

   __X_ **PSD (CO, NO_x, SO_2, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, GHG)**

2. Source Description:

   South Field Energy LLC (SFE) has submitted a PTI application for the installation of a nominal net 1,150 MW Potential combined-cycle gas turbine (CCGT) electric generating facility located in Columbiana County.

   As noted above, this project will trigger PSD review forCO, NO_x, SO_2, PM_{10}, $PM_{2.5}$, VOC, H_2SO_4, GHG. The Title V permit program applies to this project once operating. When built and operating it will be subject to the Title V Permit Program.

   This facility is similar to the Lordstown Energy (P0117655), Oregon Clean Energy Center (P0117413) and the Carroll County Energy Center (P0113762), hence similar permit terms and conditions. The facility will utilize two GE Model 7HA.02 combustion turbines with natural gas being the primary fuel and Ultra Low Sulfur Diesel (ULSD) fuel being the secondary fuel. The design net plant base heat rate is 7,165 Btu/kW-hr HHV (ISO conditions without duct firing) which is an indicator of the efficiency of heat input being converted to electricity.

3. Facility Emissions and Attainment Status:

   This facility is projected to be an area source for HAPs. The following chart identifies the facility's PTE:

Pollutant	CCGT-1* tpy	CCGT-2* tpy	Ancillary Equipment** tpy	Total*** Tons per rolling, 12-month period
PM_{10}	128.91	128.91	17.6	275.5
$PM_{2.5}$	128.91	128.91	10.6	268.4
SO_2	23.46	23.46	0.4	47.3
NO_x	151.27	151.27	17.9	320.4
CO	108.06	108.06	20.1	236.2
VOC	50.63	50.63	2.5	103.8
H_2SO_4	28.99	28.99	0.03	58.0
NH_3	117.50	117.50	0.0	235.0
Pb	$3.84E^{-03}$	$3.84E^{-03}$	$1.45E^{-04}$	$6.2E^{-03}$
CO_{2e}	2,045,634.5	2,045,634.5	33,119	4,124,388

*Includes duct burners
**Ancillary equipment includes an auxiliary boiler (B001), emergency generator (P003), emergency fire pump (P004), and the wet cooling towers (P005 and P006).
***ISO conditions per the permit application.

Columbiana County is in attainment concerning NAAQS for all criteria pollutants.

4. Source Emissions:

Combined cycle combustion turbine (3,131 MMBtu/hr heat input turbine at ISO conditions, natural gas (NG) firing with evaporative cooler on and 800 MMBtu/hr maximum heat input natural gas-fired duct burner) with dry low NOx combustors, selective catalytic reduction (SCR), catalytic oxidizer, and wet injection for ULSD firing. Heat input for ULSD firing at ISO conditions, with evaporative cooler on is 3,173 MMBtu/hr.

Pollutant	Emission Rate (lb/MMBtu)	Emission Rate (ppmvdc)	Emission Rate (tons per rolling, 12-month period)*	BACT/BAT
NO_x CTG only CTG w/DB CTG w/ULSD	 0.0075 0.0075 0.0198	 2.0 2.0 5.0	 151.27	2.0 ppmvdc NG 5.0 ppmvdc ULSD **DLN-NG Wet injection when firing ULSD and SCR (both fuels)
VOC CTG only CTG w/DB CTG w/ULSD	 0.0013 0.0026 0.0028	 1.0 2.0 2.0	 50.63	2.0 ppmvdc (w/DB-NG and ULSD) 1.0 ppmvdc (w/out DB-NG) Good combustion controls and oxidation catalyst
CO CTG only CTG w/DB CTG w/ULSD	 0.0046 0.0046 0.0048	 2.0 2.0 2.0	 108.06	2.0 ppmvdc Good combustion controls and oxidation catalyst
$PM_{10}/PM_{2.5}$ CTG only	 0.0077	 n/a	 128.91	0.0049 lb/MMBtu

CTG w/DB CTG w/ULSD	0.0069 0.019	n/a n/a		(w/DB-NG) 0.0068 (w/out DB-NG) 0.019 lb/MMBtu (ULSD) Good combustion controls
SO_2 CTG only CTG w/DB CTG w/ULSD	0.0014 0.0014 0.0015	n/a n/a n/a	23.46	0.0015 lb/MMBtu Low sulfur fuels
H_2SO_4 CTG only CTG w/DB CTG w/ULSD	0.0017 0.0017 0.0019	n/a n/a n/a	28.99	0.0011 lb/MMBtu Low sulfur fuels
GHG (CO_{2e})	7,165 Btu/net kW-hr (at full load ISO conditions NG firing w/out duct burning)	n/a	2,045,634.5	High efficient combustion technology

*Per emissions unit basis
**Dry low NOx (DLN) burners for NG firing and selective catalytic reduction (SCR) for both NG and ULSD.

99 MMBtu/hr dual fuel [natural gas and ultra-low sulfur diesel (ULSD)-fired] boiler with low-NOx burners and flue gas recirculation:

Pollutant	Emission Rate (lb/MMBtu)	Maximum Emission Rate (lb/hr)	Maximum Emission Rate (tons per rolling, 12-month period) 3560 hrs. gas/1440 hrs ULSD)	BACT/BAT
NO_x w/gas NO_x w/ULSD	0.020 0.1	9.90	10.65	Flue gas recirculation (FGR), low NO_x burner, and NG/ULSD

VOC w/gas VOC w/ULSD	0.006 0.006	0.59	1.49	Good combustion controls and NG/ULSD
CO w/gas CO w/ULSD	0.055 0.080	7.92	15.39	Good combustion controls and NG/ULSD
$PM_{10}/PM_{2.5}$ w/gas $PM_{10}/PM_{2.5}$ w/ULSD	0.008 0.060	5.94	5.69	NG/ULSD
SO_2 w/gas SO_2 w/ULSD	0.0014 0.0015	0.15	0.35	NG/ULSD
H_2SO_4 w/gas H_2SO_4 w/ULSD	0.00011 0.00011	0.011	0.03	NG/ULSD
GHG (CO_{2e}) w/gas GHG (CO_{2e}) w/ULSD	117.65* 159.29* *used for annual tons compliance value; short-term fuel limits for CO_2: 120 for NG and 160 for ULSD	15,828	32,171	Good combustion controls, natural gas combustion, and ULSD

2,198 kW mechanical (2,947 hp & 19.32 MMBtu/hr) emergency diesel generator (P003):

Pollutant	Emission Rate (g/kW-hr)	Emission Rate (lb/hr)	Emissions Rate (tons per rolling, 12-month period)	BACT/BAT
NO_x	5.61	27.18	6.8	State-of-the-art combustion design
VOC	0.79	3.84	0.96	State-of-the-art combustion design
CO	3.5	16.96	4.24	State-of-the-art combustion design
$PM_{10}/PM_{2.5}$	0.2	0.97	0.24	State-of-the-art combustion design

SO_2	0.0015 lb/MMbtu	0.03	0.01	ULSD
H_2SO_4	0.000132	0.00064	0.00016	ULSD
GHG (CO_{2e})	n/a	3,431	858	Efficient design

311 hp (232.1 kW mechanical AND 2.64 MMBtu/hr) emergency fire pump:

Pollutant	Emission Rate (g/kW-hr)	Emission Rate (lb/hr)	Emissions Rate (tons per rolling, 12-month period)	BACT/BAT
NO_x	3.5	1.79	0.45	State-of-the-art combustion design
VOC	0.5	0.25	0.06	State-of-the-art combustion design
CO	3.5	1.79	0.45	State-of-the-art combustion design
$PM_{10}/PM_{2.5}$	0.2	0.1	0.03	State-of-the-art combustion design
SO_2	0.0015 lb/MMBtu	0.004	0.001	ULSD
H_2SO_4	0.000132	0.000067	0.000017	ULSD

Wet Cooling Towers* (P005 and P006):

Pollutant	Emission Rate (lb/hr and tons per rolling, 12-month period for each emissions unit)
PM10	1.33 and 5.85
PM2.5	0.534 and 2.34
VE	Shall not exceed 10% opacity as a 6-minute average. The presence of condensed water vapor shall not be deemed a violation for failure of stack emissions meeting this visible emission limitation.

*Per the permit application, the circulating water, having gained heat from the condensing steam, needs to be cooled in order to be reused as cooling water. This cooling is accomplished by means of a mechanical draft cooling tower. A mechanical draft cooling tower provides cooling of the circulating water by spraying (warm) circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air, which is being drawn in through the sides of the tower, towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water may be entrained into this air flow. These droplets of circulating water (called drift) contain dissolved solids. Specially designed drift eliminators are typically located above the water sprays to remove most of these droplets and return them to the fill. But a small fraction of these droplets can escape into the fan discharge into the atmosphere. These droplets then evaporate, and the particulates in these droplets are a source of particulate (PM10/PM2.5) emissions.

Ohio Air Toxics Modeling:

Modeling was completed for Acetaldehyde, NH3, formaldehyde, toluene, xylenes, and H2SO4 to demonstrate compliance with MAGLC criteria established in the evaluation method described in the Ohio EPA document entitled Option A – Review of New Sources of Air Toxic Emissions (Ohio EPA 1986).

The worst case pollutant was H_2SO_4, with an emission rate of 6.96 lbs/hr and a MAGLC of 4.76 µg/m3. The model's max predicted impact was 1.51 µg/m3.

Air Dispersion Modeling:

Air dispersion modeling was conducted for CO, nitrogen dioxide (NO_2), SO_2, PM_{10}, and $PM_{2.5}$ to demonstrate compliance with the NAAQS and PSD Increments. The project's air quality dispersion modeling was submitted to Ohio EPA's Central Office and was reviewed by William Kenny.

5. Conclusion:

Issue Draft PSD PTI.

STAFF DETERMINATION FOR THE APPLICATION TO CONSTRUCT UNDER THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS FOR SOUTH FIELD ENERGY, LLC WELLSVILLE, OHIO PERMIT NUMBER P0119495

The Clean Air Act and regulations promulgated thereunder require that major air pollution sources undergoing construction or modification comply with all applicable Prevention of Significant Deterioration (PSD) provisions and nonattainment area New Source Review requirements. The federal PSD rules govern emission increases in attainment areas for major sources, which are sources with the potential to emit 250 tons per year or more of any pollutant regulated under the Clean Air Act, or 100 tons per year or more if the source is included in one of 28 source categories. In nonattainment areas, the definition of major source is one having at least 100 tons per year potential emissions. A major modification is one resulting in a contemporaneous increase in emissions which exceeds the significance level of one or more pollutants. Any changes in actual emissions within a five-year period are considered to be contemporaneous. In addition, Ohio now has incorporated the PSD and NSR requirements by rule under OAC 3745-31.

Both PSD and nonattainment rules require that certain analyses be performed before a facility can obtain a permit authorizing construction of a new source or major modification to a major source. The principal requirements of the PSD regulations are:

1. Best Available Control Technology (BACT) review - A detailed engineering review must be performed to ensure that BACT is being installed for the pollutants for which the new source is a major source.

2. Ambient Air Quality Review - An analysis must be completed to ensure the continued maintenance of the National Ambient Air Quality Standards (NAAQS) and that any increases in ambient air pollutant concentrations do not exceed the incremental values set pursuant to the Clean Air Act.

For nonattainment areas, the requirements are:

1. Lowest Achievable Emissions Rate (LAER) - New major sources must install controls that represent the lowest emission levels (highest control efficiency) that has been achieved in practice.

2. The emissions from the new major source must be offset by a reduction of existing emissions of the same pollutant by at least the same amount, and a demonstration must be made that the resulting air quality shows a net air quality benefit. This is more completely described in the Emission Offset Interpretative Ruling as found in Appendix S of 40 CFR Part 51.

3. The facility must certify that all major sources owned or operated in the state by the same entity are either in compliance with the existing State Implementation Plan (SIP) or are on an approved schedule resulting in full compliance with the SIP.

For rural ozone nonattainment areas, the requirements are:

1. LAER - New major sources must install controls that represent the lowest emissions levels (highest control efficiency) that has been achieved in practice.

2. The facility must certify that all major sources owned or operated in the state by the same entity are either in compliance with the existing SIP or are on an approved schedule resulting in full compliance with the SIP.

Finally, New Source Performance Standards (NSPS), SIP emission standards and public participation requirements must be followed in all cases.

SITE DESCRIPTION

The facility will be located near Wellsville, Ohio, which is in Columbiana County. This area is classified as attainment for carbon monoxide (CO); nitrogen oxides (NOx); sulfur dioxide (SO2); particulate matter (PM) with a diameter equal to or less than 10 microns (PM10); PM with a diameter equal to or less than 2.5 microns (PM2.5); volatile organic compounds (VOC); greenhouse gases (GHG); lead (Pb); sulfuric acid mist (H2SO4); and air toxics.

FACILITY DESCRIPTION

South Field Energy, LLC (SFE) is proposing to construct a nominal 1,150-megawatt (MW) combined cycle gas turbine (CCGT) facility (hereinafter “the Facility”) that will utilize CCGT technology in a 2x2x2 configuration.

The Facility is intended to operate as a base-load facility and is proposed to be available to operate up to 8,760 hours per year, incorporating a range of load conditions. The Facility also seeks the flexibility to operate with frequent starts in order to meet energy demands. Air emissions from the proposed Facility primarily consist of products of combustion from the CTGs, HRSG duct burners, and ancillary equipment and will be subject to Prevention of Significant Deterioration (PSD) requirements.

PROJECT DESCRIPTION

The Facility will utilize General Electric (GE) Model 7HA.02 combustion turbine generators (CTGs). Duct firing will be incorporated into the Facility’s design using natural gas only. An auxiliary boiler will be used to assist plant start-up and maintain warm-start conditions during standby periods. Other ancillary equipment having emissions includes an emergency generator and an emergency fire pump. Primary fuel for CTG and auxiliary boiler firing operations will consist of natural gas with ultra low sulfur diesel (ULSD) fuel as the secondary fuel. The emergency generator and emergency fire pump will be fired with ULSD fuel. The Facility will utilize water-cooled condensers to cool the steam discharged from the steam turbines and the circulating water will be cooled by wet mechanical draft cooling towers.

The Project will include the following major and ancillary equipment:

- Two combustion turbine generators (CTGs);
- Two heat recovery steam generators (HRSGs) with supplemental duct firing;
- Two steam turbine generators (STG);

- Two water cooled condensers;
- Two wet mechanical draft cooling towers
- One 2,000-kilowatt (kW) emergency diesel generator;
- One natural gas-fired, 99-million British thermal units (MMBtu) steam production auxiliary boiler;
- One 311-horsepower (hp) emergency fire pump; and
- Storage tanks for aqueous ammonia (NH_3), ultra low sulfur diesel (ULSD) and water.

Combustion Turbine Generators

Thermal energy will be produced in the two CTGs through the ignition of natural gas as the primary fuel. ULSD fuel may be employed for up to 1,440 hours per year when natural gas is not available. Each CTG is capable of running independently of the other. The thermal energy is converted to mechanical energy in the CTG that drives its integral compressor and electric generator. The maximum heat input rate of each CTG while burning natural gas is 3,131 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent load, 59 degrees Fahrenheit (°F) and 60 percent relative humidity with the evaporative cooler on. Under the same conditions while burning ULSD fuel, the maximum heat input rate of each CTG would be 3,173 MMBtu/hr.

Heat Recovery Steam Generators and Duct Burners

In combined cycle configuration, each CTG will exhaust through a dedicated HRSG to generate steam from the waste heat energy in the exhaust gas. Each HRSG will be equipped with supplemental firing via a duct burner. The duct burners provide additional thermal energy to the HRSG, to provide more steam to the STG during periods of high electricity demand. The duct burners will be natural gas-fired and each will have a maximum input capacity of 800 MMBtu/hr (HHV), although the duct burners will not always operate at maximum capacity. The use of the duct burners will vary based upon different temperature and operating conditions.

Steam Turbine Generators/Condensers

Steam generated in the HRSGs will be expanded through multi-stage, reheat-capable, condensing steam turbines. The discharge steam from the steam turbines will be directed to water-cooled condensers. The condenser cooling water (also referred to as circulating water) is the heat sink for the heat released by the condensing steam. The circulating water provides non-contact cooling using heat exchangers. Rotational power created by the steam turbines will be converted to electric power via the connected generators.

Wet Mechanical Draft Cooling Towers

The circulating water, having gained heat from the condensing steam, needs to be cooled in order to be reused as cooling water. This cooling is accomplished by means of wet mechanical draft cooling towers. Mechanical draft cooling towers provide cooling of the circulating water by spraying (warm) circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water may be entrained into this air flow. These droplets of circulating water (called drift) contain dissolved solids. Specially designed drift eliminators are typically located above the water sprays to remove most of these droplets and return them to the fill. However, a small fraction of these droplets can escape into the fan discharge into the atmosphere. These droplets then evaporate, and the particulates in these droplets are a source of particulate (PM/PM10/PM2.5) emissions.

Auxiliary Boiler

The auxiliary boiler will use natural gas as the primary fuel and ULSD as the secondary fuel, and operate as needed to keep the HRSG warm during periods of Facility shutdown and provide steam to the STG during start-ups. The auxiliary boiler will have a maximum input capacity of 99 MMBtu/hr and will be limited to 5,000 hours of total operation per year with an annual limit of 1,440 hours on ULSD.

Emergency Diesel Generator

The Facility will have an emergency diesel generator with a nominally rated electrical output of 2,000 kilowatts (kW) powered with a 2,947-horsepower (hp) diesel engine to provide on-site emergency power capabilities independent of the utility grid. The emergency generator will fire ULSD fuel and will typically only operate for testing and to maintain operational readiness in the event of an emergency. A small ULSD storage tank will be integrated into this equipment. Routine operation of the generator will be limited to a maximum of 500 operating hours per year.

Emergency Diesel Fire Pump

The Facility will have a 311-hp (232.1-kW mechanical) emergency fire pump to provide on-site firefighting capabilities independent of the off-site electrical utilities grid. The emergency fire pump will fire ULSD fuel and will typically only operate for testing and to maintain operational readiness in the event of an emergency. A small ULSD storage tank will be integrated into this equipment. Similar to the emergency generator, it will be limited to a maximum of 500 operating hours per year.

Aqueous Ammonia Storage Tanks

The proposed Facility will have tanks for storage of 19 percent aqueous NH3 for use in the SCR system. The tanks will be equipped with secondary containment sized to accommodate the entire volume of one tank and sufficient freeboard for precipitation. The tanks will be located outdoors within an impermeable containment area.

Fuel Oil Storage Tank

The proposed Facility will have a nominal 3 million gallon capacity above ground fixed roof fuel oil storage tank for storing ULSD as a backup fuel. The tank will be equipped with secondary containment sized to accommodate the entire volume of the tank and sufficient freeboard for precipitation. This storage tank will be exempt from permitting requirements in accordance with OAC 3745-31-03(A)(1)(l)(vi).

NEW SOURCE REVIEW (NSR)/PSD APPLICABILITY

The Facility will generate significant levels of criteria pollutant emissions including NO_x, SO_2, CO, VOC, H_2SO_4, GHGs, PM_{10} and $PM_{2.5}$. For PSD purposes, the installation of this facility makes SFE a major facility. A PSD analysis was required for any increase in emissions of a pollutant exceeding the PSD threshold emissions level, or the significance levels. Non-Attainment New Source Review was not applicable, due to attainment status.

SFE is subject to MACT. The facility is subject to 40 CFR Part 63, Subpart ZZZZ.

Summary of Proposed Potential Emissions and Applicable Regulatory Thresholds

Pollutant	Annual Emissions (tpy)	PSD Major Source Threshold (tpy)	PSD Significant Emission Rate (tpy)	PSD Applies? (Yes/No)
PM_{10}	275.5	100	15	Yes
$PM_{2.5}$	268.4	100	10	Yes
SO_2	47.3	100	40	Yes
NO_x	320.4	100	40	Yes
CO	236.2	100	100	Yes
VOC	103.8	100	40	Yes
H_2SO_4	58.0	100	7	Yes
Pb	6.2×10^{-3}	10	0.6	No
GHGs[a]	4,124,388	NA	75,000	Yes

[a]GHGs are expressed as CO_{2e}. Note that as of a June 23,2014 Supreme Court Decision, GHG emissions cannot determine major source status. USEPA issued a Policy Memo dated July 24, 2014, indicating that it intends to pply the current GHG SER threshold for requiring PSD BACT review for GHG for "anyway" sources.

PM_{10}= Particulate Matter <10 microns
$PM_{2.5}$ = Particulate Matter <2.5 microns
SO_2= Sulfur Dioxide
NO_x = Nitrogen Oxides
CO = Carbon Monoxide
VOC = Volatile Organic Compound
H_2SO_4 = Sulfuric Acid
Pb = Lead
GHG (CO_{2e}) = Greenhouse Gases (CO_2 equivalent)

Based upon the above information, PSD review is required for PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, H_2SO_4 and GHGs.

BACT REVIEW

As part of the application for any source regulated under the PSD requirements, an analysis must be conducted that demonstrates that Best Available Control Technology will be employed by the source. In this specific case, the BACT analysis was conducted for PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, H_2SO_4 and GHGs. Each pollutant will be reviewed separately.

The application used a "top-down" approach to determine an appropriate level of control.

The basic steps to be followed are:

- Identify all available potential control options;
- Eliminate technically infeasible options;
- Rank remaining technologies by control effectiveness;
- Evaluate the feasible controls by performance and cost analysis; and
- Select BACT

CCGT - BACT Analysis for NOx

In combined cycle gas turbines, NOx is formed during the combustion of fuel and is generally classified as either thermal NOx or fuel-related NOx. Thermal NOx results when atmospheric nitrogen is oxidized at high temperatures to produce nitrogen oxide (NO), nitrogen dioxide (NO2), and other oxides of nitrogen. The major factors influencing the formation of thermal NOx are peak flame temperatures, availability of oxygen at peak flame temperatures, and residence time within the combustion zone. Fuel-related NOx is formed from the oxidation of chemically bound nitrogen in the fuel. Fuel-related NOx is generally minimal for natural gas combustion. As such, NOx formation from combustion of natural gas is due mostly to thermal NOx formation. ULSD typically has a low fuel-bound nitrogen content, so thermal NOx also represents the majority of ULSD NOx emissions.

Reduction in NOx formation can be achieved using combustion controls and/or flue gas treatment. Available combustion controls include water or steam injection and low emission combustors. Modern CTGs generally use lean pre-mix low emission combustors for natural gas firing. In these types of combustors, natural gas and air are pre-mixed prior to combustion. This approach limits the formation of NOx because there are lower peak flame temperatures. Using this approach, lean combustors are designed to operate below the stoichiometric ratio, thereby reducing the thermal NOx formation within the combustion chamber.

The CTGs proposed for the Facility utilize a lean pre-mix combustion technology during gas firing and water injection during ULSD firing. In addition, gases from the CTG (and duct burner) will exhaust through an SCR system (discussed below) to further reduce NOx emissions to 2.0 ppmvdc during natural gas firing with and without duct firing, and 5.0 ppmvdc during ULSD firing.

The following discussion demonstrates that the proposed NOx emission rates for the combined cycle gas turbine units and ancillary equipment are considered BACT.

Identification of Control Options

The ranking of technically feasible NOx control technologies identified for new large (>100 MW) combined cycle turbines are as follows:

SCR: This is a catalytic reduction technology using ammonia as a reagent that has been in widespread use on new combined cycle turbines for over 20 years. SCR is widely recognized as the most stringent available control technology for NOx emissions from combined cycle turbines.

DLN Combustion: Turbine vendors offer what is known as lean pre-mix combustors for natural gas firing, which limits NOx formation by reducing peak flame temperatures. DLN is generally used in combination with SCR.

Water or Steam Injection: Water or steam injection has been historically used for both natural gas- and oil-fired turbines, but for new turbines is generally only used for liquid fuel firing. Water or steam injection is less effective than SCR or DLN.

SCR is an add-on NOx control technology that is placed in the exhaust stream following the CTG/duct burner. SCR involves the injection of NH3 into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH3 reacts with the NOx contained within the flue gas to form N2 and H2O in accordance with the following chemical reactions:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$

The catalyst's active surface is usually a noble metal (platinum), base metal (titanium or vanadium) or a zeolitebased material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogeneous material that forms both the active surface and the substrate. NH3 is fed and mixed into the combustion gas upstream of the catalyst bed in greater than stoichiometric amounts to achieve maximum conversion of NOx. Excess NH3 which is not reacted in the catalyst bed is subsequently emitted through the stack; this is called "ammonia slip."

An important factor that affects the performance of an SCR system is the operating temperature. The optimal temperature range for standard base metal catalysts is between 400°F and 800°F. Because the optimal temperature is below the CTG exhaust temperature but above the stack exhaust temperature, the catalyst needs to be located within the HRSG.

An undesirable side effect of the use of SCR systems is the potential for formation of ammonium bisulfate and ammonium sulfate, referred to as ammonium salts. These salts are reaction products of sulfur trioxide (SO3) and NH3. Ammonium salts are corrosive and can stick to the heat exchanger surfaces, duct work, or the stack at low temperatures. In addition, ammonium salts are considered PM10/PM2.5 and, therefore, increase the emissions of these criteria pollutants. Use of low sulfur fuels such as natural gas and ULSD minimizes the formation of SO3 and the subsequent formation of these ammonium salts.

Search of RBLC Determinations

The search of the RBLC and other available permits identified the lowest permitted NOx limit for a natural gas-fired combined cycle gas turbine with duct burning is 2.0 ppmvdc. The lowest permitted NOx level for ULSD firing is 5.0 ppmvdc. The details of this review are presented in Appendix C, Table C-1. All of the projects permitted at these NOx levels use SCR systems, typically in combination with lean pre-mix combustion for gas firing and water or steam injection for ULSD firing. Therefore, the most stringent level of NOx control identified for similar combined cycle gas turbine units is SCR in combination with low-NOx combustors to achieve 2.0 ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing.

BACT Determinations

A NOx emission limit of 2.0 ppmvdc for natural gas firing with and without duct burning, and 5.0 ppmvdc for ULSD firing, is proposed as BACT for the proposed Facility. This level of emissions will be achieved through the application of DLN burners (natural gas firing) and water injection (ULSD firing) in combination with SCR. This emission level is consistent with the most stringent level of control found during the RBLC search and has been demonstrated in practice.

Since this most stringent level of control is being proposed, an economic analysis with respect to the cost effectiveness of alternative controls has not been conducted. Energy related impacts are directly translatable into economic impacts, and similarly have not been examined.

One collateral environmental impact that has been identified for SCR is due to the use of ammonia as a reagent, and the resulting emissions of ammonia "slip" that can occur. The Facility is proposing an emission limit for ammonia slip of 5.0 ppmvdc, which is consistent with ammonia slip limits for recent approvals for similar facilities in Ohio. This stringent ammonia limit assures that collateral impacts are adequately minimized for the use of SCR.

<u>CCGT - BACT Analysis for VOC</u>

CTGs have inherently low VOC emission rates. Emissions of VOC from a CTG occur as a result of incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO2 and water. VOC emissions can be minimized by the use of good combustion controls and add-on controls as described below.

The CTGs proposed for the Facility will utilize good combustion controls and exhaust through an oxidation catalyst to further reduce VOC emissions. For natural gas firing, emissions of VOC from the exhaust stack will be limited to 2.0 ppmvdc with duct firing and 1.0 ppmvdc without duct firing. For ULSD firing, emissions of VOC from the exhaust stack will be limited to 2.0 ppmvdc.

Identification of Control Options

The ranking of technically feasible VOC control technologies identified for new large (>100 MW) combined cycle turbines are as follows:

Oxidation Catalyst: An oxidation catalyst system provides the most stringent level of control available for VOC emissions from a combined cycle gas turbine unit.

Combustion Controls: Turbine vendors have designed lean pre-mix combustors for natural gas firing to provide a high degree of fuel oxidation. Water injected combustors for ULSD firing are also designed for efficient combustion. Combustion controls are commonly used in combination with an oxidation catalyst to minimize VOC emissions. However, combustion controls alone are less effective than an oxidation catalyst in combination with combustion controls.

Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. The optimal location for VOC control, in the 900°F to 1,100°F temperature range, would be upstream of the HRSG or in the front-end section of the HRSG. However, at the high temperatures necessary to make the oxidation catalyst optimized for VOC reduction, there is the undesirable result of causing substantially more conversion of SO2 to SO3. As described previously, SO3 may react with H2O and/or NH3 to form H2SO4 and/or ammonium salt (PM10/PM2.5). Therefore, placement of the oxidation catalyst is most frequently in the “cooler” section of the HRSG, normally just upstream of the SCR system.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for VOC BACT/LAER precedents is presented in Appendix C, Table C-2. Based on this search, use of an oxidation catalyst is the most stringent level of VOC control for natural gas-fired combined cycle gas turbines. Therefore, the use of an oxidation catalyst is considered to represent the most stringent level of VOC control achieved in practice.

The lowest VOC limit for any natural gas-fired project presented in Table C-2 is 0.3 ppmvdc. This limit is for the Chouteau Power Plant in Mayes County, Oklahoma. This plant has four Siemens V84.3 combined cycle gas turbine units, two of which have duct firing. The unfired units (i.e., no duct firing) went on line in 1999 and the duct fired units went online in 2009. However, none of these units actually have an oxidation catalyst, so this facility does not actually have the most stringent level of VOC control equipment installed. A memorandum in support of a Title V renewal for this facility was issued by the Oklahoma Department of Environmental Quality on October 21, 2013. This memo indicates the 0.3 ppmvdc limit (which applies to all the units, including with and without duct firing) was based on vendor data. However, the memo also states that the VOC emissions at full load (both with and without duct firing) are 0.0028 lb/MMBtu, which actually corresponds to 2.2 ppmvdc. The permit contains lb/hr limits that match the 0.0028 lb/MMBtu value at full load. Therefore, there is a disconnect in the Chouteau ppmvdc and lb/hr limits. VOC emissions of 2.0 ppmvdc are more consistent with the range of VOC data in Appendix C, and are consistent with the proposed duct-fired VOC BACT for the Facility.

The second lowest VOC limits for any project presented in Appendix C are for the natural gas-fired Brunswick Power Facility and Warren County projects in Virginia, which have permitted VOC limits of 0.7 ppmvdc (unfired) and 1.6 ppmvdc (duct-fired). These projects will use Mitsubishi 501G combined cycle gas turbines with duct firing and will have oxidation catalysts installed for VOC (and CO) control. Brunswick Power Project is currently under construction, and the Warren County Power Station went into commercial operation on December 10, 2014. Warren County has recently demonstrated these VOC limits in practice.

Appendix C also lists two dual fuel combined cycle units approved since 2012, which are the Garrison Energy Center in Delaware and the Pioneer Valley Energy Center (PVEC) in Massachusetts. The Garrison Energy Center is currently under construction with commercial operation of the first unit scheduled for June 2015. PVEC has not yet commenced construction. The Garrison VOC limit for ULSD (4.5 lb/hr) correspond to approximately 1.6 ppmvdc at full load. PVEC (which does not have duct-firing capability) was not subject to PSD review for VOC, but has an approval with state BACT limits for VOC of 1.0 ppmvdc on natural gas and 6.0 ppmvdc on ULSD.

Appendix C also lists several older natural gas-fired combined cycle projects, which have permitted VOC limits with duct firing of 1.5 to 1.7 ppmvdc (duct-fired). These projects all have oxidation catalysts for VOC (and CO) control. Three of these projects (Kendall, Mystic, and Fore River) have demonstrated 1.5 to 1.7 ppmvdc in practice, while the more recent projects have not yet demonstrated compliance with these limits. Kendall and Fore River are also approved for dual fuel operation. Kendall demonstrated compliance with VOC limits on liquid fuel of 1.5 ppmvdc without duct firing and 2.5 ppmvdc with duct firing. Fore River demonstrated compliance with a VOC limit with oil firing of 7.0 ppmvdc (with and without duct firing).

Except for the Chouteau, Brunswick, and Warren County projects, all other projects listed in Appendix C have unfired VOC limits (gas firing) of 1.0 ppmvdc or greater. Several projects have duct-fired VOC limits less than 2.0 ppmvdc. The proposed VOC BACT is as or more stringent than most of the VOC limits listed in Table C-2. As described above, the Chouteau 0.3 ppmvdc value is inconsistent with the lb/hr limits. Brunswick is still under construction and its limits have not yet been demonstrated in practice. Kendall has the lowest demonstrated VOC limit of 1.5 ppmvdc for duct firing with natural gas as well as oil firing without duct firing, but these remain aggressive commercial limits not typical of most projects. The majority of the recent BACT precedents in Table C-2 support the proposed Facility VOC BACT limits of 2.0 ppmvdc for natural gas firing with duct firing, 1.0 ppmvdc for natural gas without duct firing, and 2.0 ppmvdc for ULSD firing.

BACT Determinations

The Facility is proposing to use the most stringent available control equipment for VOC, and is proposing VOC BACT limits consistent with this most stringent level of control as reflected by the majority of the VOC data in Appendix C. Emissions of VOC from the exhaust stacks will be limited to 2.0 ppmvdc for natural gas firing with duct firing, 1.0 ppmvdc for natural gas without duct firing, and 2.0 ppmvdc for ULSD firing. This level of emissions will be achieved via good combustion control and an oxidation catalyst.

Since the most stringent control equipment for VOC is being proposed, an economic analysis with respect to the cost-effectiveness of alternative controls has not been conducted. Energy related impacts are directly translatable into economic impacts, and similarly have not been examined.

One collateral environmental impact that has been identified with an oxidation catalyst is oxidation of SO2 to SO3. SO3 then forms H2SO4 in the presence of H2O and/or ammonia salts in the presence of NH3. The conversion of SO2 to SO3 is adequately minimized by use of low sulfur natural gas as the primary combined cycle gas turbine fuel, and ULSD as the secondary fuel, along with placement of the oxidation catalyst just upstream of the SCR system. This lower temperature oxidation catalyst placement minimizes the oxidation of SO2 to SO3 that would otherwise occur, with placement of the oxidation catalyst at the HRSG outlet.

CCGT - BACT Analysis for CO

Emissions of CO from combustion occur as a result of incomplete combustion of fuel. CO emissions are minimized by the use of proper combustor design, good combustion practices, and add-on controls. Since the potential emissions from the Facility exceed PSD significance thresholds, BACT is required for CO emissions. As indicated previously, pollutants that comply with BACT meet BAT requirements.

The CTGs proposed for the Facility will utilize good combustion controls and exhaust through an oxidation catalyst to reduce CO emissions. Emissions of CO from the exhaust stack will be limited to 2.0 ppmvdc for natural gas firing with and without duct firing, as well as ULSD firing.

The following discussion demonstrates that the proposed CO emission rates for the combined cycle gas turbines satisfy BACT.

Identification of Control Options

The ranking of technically feasible CO control technologies identified for new large (>100 MW) combined cycle turbines are as follows:

Oxidation Catalyst: An oxidation catalyst system provides the most stringent level of control available for CO emissions from a combined cycle gas turbine unit.

Combustion Controls: Turbine vendors have designed lean pre-mix combustors for natural gas firing to provide a high degree of fuel oxidation. Water injected combustors for ULSD firing are also designed for efficient combustion. Combustion controls are commonly used in combination with an oxidation catalyst to minimize CO emissions. However, combustion controls alone are less effective than an oxidation catalyst in combination with combustion controls.

Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. CO reduction efficiencies in the range of 80 to 90 percent are typical, although CO reduction may at times be less than these values due to the low inlet concentrations expected from the combined cycle gas turbine units.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for CO BACT/LAER precedents are presented in Appendix C, Table C-3. Based on this search, use of an oxidation catalyst is the most stringent level of CO control for natural gas fired and dual fuel combined cycle gas turbines. Therefore, the use of an oxidation catalyst is considered to represent the most stringent level of CO control achieved in practice.

The lowest CO limit for any project presented in Table C-3 for natural gas firing is 0.9 ppmvdc without duct firing. This limit is for the Kleen Energy Systems project in Connecticut. Kleen Energy also has a CO limit of 1.7 ppmvdc for natural gas firing with duct firing, and a CO limit of 1.8 ppmvdc for ULSD firing both with and without duct firing. The Kleen Energy Systems project (with Siemens SGT6-5000F technology) is in operation and the CO limits including the unfired natural gas 0.9 ppmvdc limit are reportedly achieved in practice. However, the practical impact of the 0.9 ppmvdc limit is that it restricts the minimum operating load of the combined cycle gas turbine to approximately 60 percent load. Normally, a well-operated modern natural gas-fired combined cycle unit with an oxidation catalyst has minimal CO emission (< 0.5 parts per million [ppm]) at 75 percent load and above. During periods of lower power demand, typically during nighttime hours, these type of units may operate at minimum load rather than shutting down in the late evening and starting up the next morning. It is during these lower load periods when the CO emissions may be between 1 and 2 ppmvdc. A very low CO limit such as 0.9 ppmvdc represents a significant operating flexibility restriction for this type of facility. In addition, the Kleen facility has a considerably higher VOC emission rate than proposed for the Facility (5.0 ppmvdc).

The second lowest (unfired) CO limits for any project presented in Appendix C are for the natural gas-fired Brunswick and Warren County projects in Virginia, which each have an unfired permitted CO limit of 1.5 ppmvdc. However, the CO permit limit for duct firing of 2.4 ppmvdc is higher than the Facility's proposed duct-fired limit of 2.0 ppmvdc. These projects will use Mitsubishi 501G combined cycle turbine generators with duct firing and will have oxidation catalysts installed for CO (and VOC) control. The Brunswick Project is still under construction, while the Warren County project recently began commercial operation. Warren County has recently demonstrated these CO limits in practice.

The Palmdale and Avenal projects in California also have unfired permitted CO limits of 1.5 ppmvdc, which will take effect after a three-year demonstration period. The Palmdale plant is in operation and the three-year demonstration period has not been completed. The Avenal plant has not been constructed.

The only other project in Table C-3 with an unfired or fired CO limit effectively less than 2.0 ppmvdc is the Footprint Salem Harbor project, which has a lb/hr limit at full load with duct firing which effectively caps the CO at approximately 1.5 ppmvdc. However, at less than maximum firing conditions, 2.0 ppmvdc is controlling limit. All the other projects listed in Table C-3 have CO limits of 2.0 ppmvdc or greater. The Facility's proposed CO limit of 2.0 ppmvdc is as or more stringent than the clear majority of CO limits listed in Table C-3.

BACT Determinations

The Facility is proposing a CO BACT emission limit of 2.0 ppmvdc for natural gas firing with and without duct firing, and also for ULSD firing. This level of emissions will be achieved via good combustion control and an oxidation catalyst. This proposal is consistent with the limits and control technologies found in the RBLC and with the majority of recent BACT determinations in Ohio and in other states.

CCGT - BACT Analysis for Particulate Matter (PM_{10}/$PM_{2.5}$)

Emissions of particulate matter from combustion can occur as a result of trace inert solids contained in the fuel and products of incomplete combustion which may agglomerate or condense to form particles. Particulate emissions can also result from the formation of ammonium salts due to the conversion of SO2 to SO3, which is then available to react with NH3 to form ammonium sulfates. All of the particulate matter emitted from the combined cycle gas turbines is conservatively assumed to be less than 2.5 microns in diameter. Therefore, PM10 and PM2.5 emission rates are assumed to be the same.

The combustion of clean-burning fuels is the most effective means for controlling particulate emissions from combustion equipment. The Facility is proposing to use natural gas as the primary fuel and ULSD as the secondary fuel for the turbines. Both of these fuels are clean-burning fuels.

For PM10/PM2.5, this evaluation does not identify and rank technically feasible control technologies, since there are no combined cycle gas turbine post-combustion control technologies available for PM/PM10/PM2.5. Post-combustion particulate control technologies such as fabric filters (baghouses), electrostatic precipitators, and/or wet scrubbers, which are commonly used on solid-fuel boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for turbine operation. SFE is not aware of any combined cycle gas turbine facilities which are equipped with any post combustion particulate control technologies.

The combined cycle units proposed for the Facility will utilize natural gas as their primary fuel to minimize particulate emissions. Emissions of PM10/PM2.5 from the exhaust stack for natural gas firing will be limited to 0.0077 lb/MMBtu (HHV) without duct-firing and 0.0069 lb/MMBtu (HHV) with duct-firing. For ULSD firing, emissions of PM10/PM2.5 from the exhaust stack will be limited to 0.019 lb/MMBtu (HHV).

The following discussion demonstrates that the proposed PM10/PM2.5 emission rates for the combined cycle gas turbines are considered BACT.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for PM/PM10/PM2.5 BACT/LAER precedents are presented in Appendix C, Table C-4. Based on this search, use of clean-burning fuels and good combustion practices are the most stringent available technologies for control of combined cycle gas turbine particulate emissions.

A review of Table C-4 indicates that PM/PM10/PM2.5 emission limits can be expressed either in lb/hr or lb/MMBtu, or in some cases in both lb/hr and lb/MMBtu. Different emission limits for the same project can also be associated with different turbine suppliers. This is illustrated by some projects which have one set of limits for one supplier and another set of limits for another supplier.

Based on review of available information, differences in PM/PM10/PM2.5 emission limits among various projects appear to be due to different emission guarantee philosophies of the various suppliers, and are not believed to be actual differences in the quantity of PM/PM10/PM2.5 emissions inherently produced by the type of turbine. The different emission guarantee philosophies are influenced by the overall uncertainties of the PM/PM10/PM2.5 test procedures, especially given reported difficulties in achieving test repeatability, and concerns with artifact emissions introduced by the general inclusion of condensable particulate emissions in permit limits in the last decade.

The Facility has proposed an unfired lb/MMBtu limit to include part load operation. Duct firing will not occur at part load, so the proposed duct-fired PM limit reflects full-load operation only. The Facility has determined that the flexibility to operate at part loads is important to the Facility's mission of providing a flexible and quick response to the future system power needs. Minimum Emissions Compliance Load turbine operation, therefore, results in the Facility's highest unfired lb/MMBtu rate of 0.0077 lb/MMBtu. It is important to note that a number of the lb/MMBtu emission rates in Table C-4 correspond to the full-load heat input rate. For comparative purposes, the Facility's full load lb/MMBtu PM10/PM2.5 emission rate (gas-fired without duct firing) rate does not exceed 0.0051 lb/MMBtu.

The lowest PM10/PM2.5 lb/MMBtu limits for any Facility presented in Table C-4 are for the Dominion Warren County project in Virginia, which are 0.0040 lb/MMBtu with duct firing and 0.0027 lb/MMBtu without duct firing. The Dominion Warren County project is based on three Mitsubishi 501GAC turbines. Mitsubishi in particular has recently taken a more aggressive approach to PM10/PM2.5 guarantees, as reflected by the Warren County project as well as the Brunswick County project in Virginia (0.0033 lb/MMBtu without duct firing and 0.0047 lb/MMBtu with duct firing).

For natural gas firing, the Facility's proposed PM10/PM2.5 limits of 0.0077 lb/MMBtu (HHV) unfired and 0.0069 lb/MMBtu (HHV) with duct-firing are in the range of the other particulate BACT limits in Table C-4. The actual guarantees for PM/PM10/PM2.5 emissions vary by manufacturer, and proposed natural gas-firing permit limits within the range of recently approved projects for a given turbine supplier are justified as PSD BACT limits.

For ULSD firing, Appendix C also lists two dual fuel combined cycle units approved since 2012, which are the Garrison Energy Center in Delaware and the PVEC in Massachusetts. The Garrison Energy Center is currently under construction with commercial operation of the first unit scheduled for June 2015. PVEC has not yet commenced construction. The Garrison PM10/PM2.5 limit for ULSD (39.4 lb/hr) corresponds to approximately 0.0193 lb/MMBtu at full load. The proposed Facility PM10/PM2.5 limit for ULSD of 0.019 lb/MMBtu is slightly more stringent than the Garrison limit. The PVEC PSD permit (not duct-fired) has a PM10/PM2.5 limit for ULSD of 0.014 lb/MMBtu. The PVEC project has not been constructed, and the PM10/PM2.5 limit for ULSD of 0.019 lb/MMBtu is an aggressive commercial limit that has not been demonstrated in practice.

Appendix C also lists two older dual fuel combined cycle gas turbine projects (Kendall and Fore River), which have less stringent PM10/PM2.5 limits for oil firing. Kendall demonstrated compliance with a PM10/PM2.5 limit on liquid fuel of 0.034 lb/MMBtu and Fore River demonstrated compliance with a PM10/PM2.5 limit on liquid fuel of 0.05 lb/MMBtu.

BACT Determinations

The Facility is proposing PM10/PM2.5 emission limits for natural gas firing of 0.0077 lb/MMBtu (HHV) without ductfiring and 0.0069 lb/MMBtu (HHV) with duct-firing. For ULSD firing, emissions of PM10/PM2.5 from the exhaust stack will be limited to 0.019 lb/MMBtu (HHV). BACT will be achieved with the most stringent available particulate control technologies, which are good combustion practices and firing clean fuels (natural gas and ULSD). The proposed ACT limits are consistent with the range of values found in the RBLC for recent BACT determinations in Ohio and in other states, given the different guarantee approaches of different turbine suppliers.

CCGT - BAT/BACT Analysis for SO_2 and H_2SO_4

Emissions of SO2 and H2SO4 are formed from the oxidation of sulfur in the fuel. Normally, all sulfur compounds contained in the fuel will oxidize, with the vast majority initially oxidizing to SO2. A small percentage will initially oxidize to SO3 in the combined cycle gas turbine combustor. Also, a portion of the fuel sulfur which initially oxidizes to SO2 will subsequently oxidize to SO3 prior to being emitted. After being formed, the SO3 and sulfate (SO4) will react to form H2SO4 and sulfate particulate.

For SO2 and H2SO4, this evaluation does not identify and rank technically feasible control technologies, since there are no combined cycle gas turbine post-combustion control technologies available for SO2/H2SO4. Post-combustion SO2/H2SO4 control technologies, such as dry or wet scrubbers which are commonly used on solid-fuel boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for turbine operation. The Facility is not aware of any combined cycle gas turbine facilities which are equipped with any post-combustion SO2/H2SO4 control technologies.

Key considerations in the development of a specific SO2/H2SO4 emission rates for a combined cycle unit are the sulfur content of the fuel, and the appropriate allowance for oxidation of fuel sulfur and SO2 to SO3. For the sulfur content of natural gas, the Facility has used the USEPA definition of “pipeline natural gas” in 40 CFR 72.2. This definition is that pipeline natural gas has a maximum sulfur content of 0.5 grains of sulfur per 100 standard cubic feet (scf). The sulfur content of ULSD (15 ppm) is very close to the sulfur content of pipeline natural gas. This corresponds to the proposed BACT SO2 emission rate of 0.0014 lb/MMBtu on natural gas and 0.0015 lb/MMBtu on ULSD.

For H2SO4, allowance is provided for conversion of fuel sulfur to SO3 and H2SO4 in the combustor, oxidation catalyst, and SCR system. This corresponds to the proposed BACT H2SO4 emission rate of 0.0017 lb/MMBtu on natural gas both with and without duct firing, and 0.0019 lb/MMBtu for ULSD firing.

The following discussion demonstrates that the proposed SO2 and H2SO4 emission rates for the combined cycle gas turbine units are considered BAT/BACT.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for SO2/H2SO4 BACT/LAER precedents are presented in Appendix C, Table C-5. This search confirms that the only SO2/H2SO4 BACT technology identified for large combined cycle turbines is use of clean fuel (i.e., natural gas and ULSD). There are no cases where any post-combustion controls have been used to control SO2/H2SO4 emissions from large combined cycle turbines.

The results in Table C-5 indicate BACT emissions for SO2 and/or H2SO4 can be expressed either as lb/MMBtu or lb/hr, or both. A relatively wide range of BACT emission rates are found in particular for gas firing, reflecting a range of assumed natural gas sulfur contents and SO2 to SO3 oxidation rates. One of the projects listed in Table C-5 (Panda Sherman) was approved without a CO oxidation catalyst, which explains the low H2SO4 rate for this project. As noted previously, a CO oxidation catalyst oxidizes some of the SO2 to SO3/H2SO4. However, the other projects in Appendix C, Table C-5 with lower H2SO4 rates appear to have assumed a very low natural gas sulfur content and/or assumed low rates for the oxidation of SO2 to SO3 from a CO catalyst. The Facility considers it prudent to use a conservative estimate for SO2 to SO3 oxidation across the CO catalyst, and a natural gas sulfur content corresponding to USEPA's definition for "pipeline natural gas" (0.5 grains of sulfur per 100 scf).

In summary, the available evidence clearly indicates that PSD BACT for SO2 and H2SO4 for combustion turbines is use of clean low-sulfur fuel (e.g., natural gas and ULSD). SO2 and H2SO4 BACT limits need to allow for a reasonable variation in the sulfur content of pipeline natural gas, which is outside the control of a given generation facility, and SO2 to SO3 oxidation from a CO catalyst.

BACT Determinations

The Facility is proposing to use the most stringent identified H2SO4 BACT control technologies (pipeline natural gas and ULSD) and is proposing an H2SO4 emission limit of 0.0017 lb/MMBtu for natural gas firing (with and without duct firing) and 0.0019 lb/MMBtu (ULSD) as BACT. This level of emissions will be achieved by combusting commercially available, pipeline-quality natural gas with a maximum sulfur content of 0.5 grains/100 scf or ULSD (maximum sulfur content of 15 ppm by weight) in the CTGs. The duct burners will only use natural gas. This emission level is consistent with the range of limits found in Appendix C, Table C-5. The emissions of H2SO4 are directly dependent on the assumed maximum sulfur content in natural gas, and the assumed SO2 to SO3 oxidation, which has substantial variability between projects.

The Facility is proposing use of pipeline-quality natural gas and ULSD as BACT for SO2. The Facility is proposing SO2 emission limits of 0.0014 lb/MMBtu (natural gas) and 0.0015 lb/MMBtu (ULSD).

CCGT - BACT Analysis for Greenhouse Gases

This section presents the BACT analysis for GHGs using methodology presented in the USEPA document *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA 2011).

The principal GHGs associated with the Facility are CO2, CH4, and nitrous oxide (N2O). Because these gases differ in their ability to trap heat, 1 ton of CO2 in the atmosphere has a different effect on global warming than 1 ton of CH4 or 1 ton of N2O. For example, CH4 and N2O have 25 times and 298 times the global warming potential of CO2, respectively. GHG emissions from the proposed Facility are primarily attributable to combustion of fuels in the combined cycle gas turbine units. There will also be minor fugitive releases of natural gas (primarily CH4) from valves and flanges associated with the natural gas piping, and of sulfur hexafluoride (SF6) from the circuit breakers in the substation. The greatest proportion of potential GHGs emissions associated with the Facility are CO2 emissions associated with combustion of natural gas or ULSD in the combined cycle gas turbines. Trace amounts of CH4 and N2O will be emitted during combustion in varying quantities depending on operating conditions. However, as indicated in Table 4-1, emissions of CH4 and N2O are negligible when compared to total CO2 emissions. As such, BACT for the combustion processes focus on the options for reducing and controlling emissions of CO2.

Summary of GHG Emissions from Combustion Equipment (tpy)

Pollutant	CO_2	CH_4	N_2O	CO_{2e}
Combined Cycle Gas Turbines (both units)	4,085,314	92	12	4,091,269

Identification of Control Options

$CO2$ is a product of combusting any carbon containing fuel, including natural gas and ULSD. All fossil fuel contains significant amounts of carbon. During complete combustion, the fuel carbon is oxidized into CO2 via the following reaction:

$$C + O2 \rightarrow CO2$$

Full oxidation of carbon in fuel is desirable because CO, a product of partial combustion, has long been a regulated pollutant and because full combustion results in more useful energy. In fact, emission control technologies required for CO emissions (oxidation catalysts) increase CO2 emissions by oxidizing CO to CO2. Recent BACT determinations for combined cycle gas turbine projects have focused on reducing emissions of CO2 through high efficiency power generation technology and use of cleaner-burning fuels. There are limited post-combustion options for controlling CO2. The USEPA has indicated in the document, *PSD and Title V Permitting Guidance forGreenhouse Gases,* that carbon capture and sequestration (CCS) should be considered in BACT analyses as a technically feasible add-on control option for CO2 (USEPA 2011). Currently, there are no combined cycle gas turbine projects utilizing CCS, and although theoretically feasible, this technology is not commercially available. Each of these control options are discussed in greater detail in the sections below.

Power Generation Efficiency

Because emissions of CO2 are directly related to the amount of fuel combusted, an effective means of reducing GHG emissions is through efficient power generation combustion technologies. By utilizing more efficient technology, less fuel is required to produce the same amount of output electricity. The Facility is proposing to use combined cycle gas turbines, which represent the most efficient fossil fuel electric generation technology commercially available.

The Facility will utilize state-of-the-art CTG technology in combined cycle mode. Combined cycle generation takes advantage of the waste heat from the CTGs, capturing that heat in the HRSG and generating steam which then powers a conventional steam turbine. Use of waste heat in this manner makes combined cycle projects considerably more efficient than conventional steam electric boiler technology. The proposed Facility will use H-class CTG technology, the latest and most efficient CTG technology, which has a "Design Base Heat Rate" (new and clean) of approximately 6,630 British thermal units per kilowatt-hour (Btu/kW-hr) (net), HHV while firing with natural gas at full load at International Organization for Standards (ISO) conditions (with no duct firing). The emphasis on GHG reductions via efficient combustion is reflected in the recently proposed NSPS for power plants and recently issued BACT determinations for similar projects.

Low Emission Fuels

Another effective method used to reduce GHG emissions is pollution prevention or the use of inherently low-emitting fuels. The Facility's combined cycle gas turbines will combust natural gas as the primary fuel source with ULSD as the secondary fuel. Table 4-2 presents a comparison of the amount of CO2 per MMBtu for the primary fossil fuels. Coal, used historically as a primary fuel for power generation, has a greater CO2 emission factor compared to natural gas and ULSD.

Comparison of CO_2 Emissions from Different Fuels (lb CO_2/ MMBtu)

Pollutant	Emission Factor
Natural Gas	119
Diesel Fuel	162
Coal	210

Carbon Capture and Sequestration (CCS)

There are limited post-combustion options for controlling CO2, the most common being CCS, which is considered a technically feasible add-on control option for CO2. CCS is a relatively new technology which requires three distinct processes:

1. Isolation of CO2 from the waste gas stream;
2. Transportation of the captured CO2 to a suitable storage location; and
3. Safe and secure storage of the captured and delivered CO2.

The first step in the CCS process is capture of the CO2 from the process in a form that is suitable for transport. There are several methods that may be used for capturing CO2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation. Exhaust streams from combined cycle combustion sources have relatively low CO2 concentrations. Only physical and chemical absorption would be considered technically feasible for a high volume, low concentration gas stream. The capital expenditure required to capture CO2 from the exhaust and compress it to the pressure required for transport and sequestration is very significant. The Report of the *Interagency Task Force on Carbon Capture and Storage* (ITF 2010) indicates that it costs approximately $105 per ton to install a post-combustion system on a new installation to capture and compress CO2 for transport and sequestration. Applying this factor to the 4,085,314 tpy of CO2 potentially emitted from the Facility's combined cycle gas turbine units and annualizing just the capital recovery cost over 10 years results in an estimated annual cost of over $60,000,000. This is clearly an excessive cost, and does not take into account the large parasitic load caused by a CCS system, which reduces the overall efficiency of the facility and increases overall emissions of CO2 and all other regulated pollutants on a per megawatt-hour (MW-hr) basis.

The next step in the CCS process is transportation of the captured CO2 to a suitable storage location. Currently, development of commercially available CO2 storage sites is in its infancy. The Facility site is an area where the suitability of geological formations for CO2 storage is being studied by the Midwest Regional Carbon Sequestration Partnership (MRCSP), which is funded by the Department of Energy. While several CO2 sequestration demonstrations have been initiated under this program, much further development is needed before a commercially available CO2 sequestration site becomes available near the Facility site. Currently, the only MRCSP CO2 sequestration site in the development phase is in northern Michigan, over 400 miles from the Facility site by land. The current plan is to test CO2 sequestrations at this site using by-product CO2 from natural gas processing. If this development phase is successful, it is conceivable that commercial CO2 sequestration could be offered at this site at some point in the future, at some scale yet to be determined.

If the Facility were to use the northern Michigan sequestration site, captured CO2 would have to be transported by pipeline. Pipelines are the most common method for transporting large quantities of CO2 over long distances. There are currently approximately 3,600 miles of existing pipeline located in the United States, but no pipelines going from the Facility site area towards Michigan. As such, a CO2 transportation pipeline would need to be constructed to the northern Michigan location. The cost for permitting and constructing this pressurized pipeline would be economically prohibitive and impractical.

It is important to note that there are no combined cycle facilities utilizing CCS. As such, this technology, while theoretically feasible, has not been demonstrated in practice for combined cycle facilities. As demonstrated above, even if it were commercially available, the cost for designing, installing, and operating this type of capture system would be prohibitive. Based upon the large costs associated with the capture, transportation, and storage of CO2, in addition to the large parasitic load, CCS is considered cost prohibitive and economically infeasible for the Facility.

Summary of Technically Feasible GHG Control Technologies

Power generation efficiency and low carbon fuels are clearly technically feasible, and in combination represent the most effect fossil fuel power generation GHG control technology demonstrated in practice. CCS, while promising, has not yet reached the stage where it is economically feasible for the Facility. The Facility is proposing to use the low carbon fuels and high efficiency combined cycle generation, so it is using the most stringent fossil fuel GHG economically feasible control technology available.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for GHG BACT precedents is presented in Appendix C, Table C-6. GHG BACT determinations in Table C-6 are expressed in varying units, including mass emission (tons or pounds per unit time), lb CO2e per MW-hr, and/or “heat rate” (Btu/kW-hr). The energy-based limits are expressed as either “gross” or “net.” Energy units (MW-hr or kilowatt-hour) are more meaningful than mass emission limits since they relate directly to the efficiency of the equipment, which is a key available BACT technology (in addition to low carbon fuel). The mass emissions are specific to the fuel firing rate of a given project and the carbon content of the fuel, but do not incorporate Facility efficiency.

The Facility is proposing an efficiency-based GHG BACT limit of 7,165 Btu/kW-hr (net). This limit is proposed as the full load performance limit for natural gas firing, without duct firing, corrected to ISO conditions. This value includes an approximately 8 percent margin for degradation over the life of the Facility. This proposed efficiency based GHG BACT limit compares favorably with the other efficiency-based GHG BACT limits in Table C-6.

BACT Determinations

As described above, options for controlling GHGs from the CTGs include:

1. Use of high-efficiency engine technology;
2. Use of low carbon fuels; and
3. Installation and operation of CCS.

As presented in Section 4.8.1.3, installation and operation of a CCS system is economically cost-prohibitive and impractical. Implementation of high-efficiency technology and low-carbon fuels is proposed. The Facility will utilize combined cycle technology which provides greater power output per fuel input, and will burn natural gas as the primary fuel and ULSD as the secondary fuel. Based upon the Facility design, and adding a reasonable degradation margin for the life of the facility, the Facility is proposing the following as BACT, for full load at ISO conditions without duct firing: 7,165 Btu/kW-hr HHV net basis. Since this is an efficiency-based limit, it covers Facility design provisions which apply to both gas and ULSD firing. However, this limit is being proposed specific to the measured Facility efficiency on natural gas firing, since that is the primary fuel. This limit is consistent with the majority of recently permitted projects. This level of performance will be achieved through utilization of high-efficiency, state-of-the-art, combustion turbine technology. The Facility will also comply with the new USEPA NSPS for GHG for electric generating units. These new Subpart TTTT standards are 1,000 lb CO2/MWh gross energy output or 1,030 lb CO2/MWh net energy output, on a rolling 12-month basis. The Facility will be a state-of-the-art high efficiency combined cycle facility and will be designed and operated to maintain compliance with the Subpart TTTT limits.

Auxiliary Boiler – BACT Analysis

This section presents the PSD BACT analysis for the auxiliary boiler. The Facility is subject to PSD review for NOx, VOC, CO, PM10/PM2.5, H2SO4, and GHG and, thus, the auxiliary boiler is subject to PSD BACT for these pollutants. The Facility includes a 99 MMBtu/hr auxiliary boiler that will have natural gas as the primary fuel and ULSD as the secondary fuel. This auxiliary boiler will be permitted for a maximum of 5,000 hours per year of operation, with up to 1,440 hours per year on ULSD.

Since the auxiliary boiler is a small, limited use emission source compared to the combined cycle gas turbine units, the BACT evaluation combines the various pollutants into a single discussion.

Identification of Control Options

The ranking of technically feasible control technologies identified for auxiliary boilers at new large (>100 MW) combined cycle facilities are as follows:

SCR: SCR systems are offered for gas and ULSD-fired boilers and provides the most stringent level of NOx control available.

Oxidation Catalyst: Oxidation catalyst systems provide the most stringent level of control available for CO/VOC emissions for gas and ULSD-fired boilers.

Combustion Controls: Boiler vendors provide ultra-low-NOx and low NOx burners for gas-fired boilers and low NOx burners for ULSD firing which also provide a high degree of fuel oxidation to control VOC, CO, and particulates.

Low Emitting Fuels: Natural gas is the lowest emitting fuel for auxiliary boilers. ULSD is also a low-emitting fuel.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for combined cycle gas turbine auxiliary boiler BACT/LAER determinations is presented in Appendix C, Table C-7.

For NOx, the most stringent level of control identified for a natural gas-fired auxiliary boiler is use of ultra- low-NOx burners to achieve an emission rate of 0.01 lb/MMBtu. No precedents were identified for use of SCR on combined cycle gas turbine facility auxiliary boilers. The majority of the natural gas-fired auxiliary boilers in Table C-7 are approved with conventional low-NOx burners at emission rates of 0.019 to 0.05 lb/MMBtu. The proposed BACT limit for NOx for the Facility's auxiliary boiler on gas of 0.02 lb/MMBtu is consistent with the low end of this range for conventional low-NOx burners. The additional expense of an ultra-low NOx burner (>$250,000 for this size boiler) is not considered justified based on the low expected use factor for this unit. For ULSD, the proposed BACT limit of 0.1 lb/MMBtu matches the single oil-fired auxiliary boiler precedent identified in Table C-7.

For VOC, the most stringent level of control identified for a natural gas-fired auxiliary boiler is 0.0015 lb/MMBtu, for a 40 MMBtu/hr auxiliary boiler for the Hickory Run project in Pennsylvania. This is much lower than most of the other auxiliary boiler VOC precedents, which are mostly all at 0.005 to 0.006 lb/MMBtu. There is no specific control equipment specified for this auxiliary boiler, so this appears to be an unusually low performance value. This limit is considered unrealistically low for a boiler of this type. All new natural gas-fired boilers, properly operated, are expected to have intrinsically low VOC emissions. There is one auxiliary boiler recently approved at Footprint Salem Harbor with an oxidation catalyst, but the VOC rate here is still set at 0.005 lb/MMBtu. The proposed BACT limit for VOC for the Facility's auxiliary boiler of 0.006 lb/MMBtu (for both natural gas and ULSD) is consistent with the majority of the precedents in Table C-7.

For CO, the most stringent level of control identified for a natural gas-fired auxiliary boiler is 0.0035 lb/MMBtu, for an 80 MMBtu/hr auxiliary boiler for Footprint Salem Harbor, which will have an oxidation catalyst. This is much lower than most of the other auxiliary boiler CO precedents, which are in the range of 0.037 to 0.0164 lb/MMBtu. Footprint Salem Harbor volunteered to install a CO oxidation catalyst on the auxiliary boiler to help reduce overall project emissions to below the 100 tpy CO PSD review threshold. For all other cases, the emissions are based on vendor burner performance and there is no CO control equipment specified for the auxiliary boiler. The proposed BACT limit for CO for the Facility's auxiliary boiler on gas of 0.055 lb/MMBtu is consistent with the range of the precedents in Table C-7. The additional expense of an oxidation catalyst ($>100,000) is not considered justified based on the low expected use factor for this unit. For ULSD, the proposed BACT limit of 0.08 lb/MMBtu matches the single oil-fired auxiliary boiler precedent identified in Table C-7.

For PM10/PM2.5, the most stringent level of control identified for a natural gas-fired auxiliary boiler is 2.5 pounds per million cubic feet (lb/MMcf) of natural gas, for a 91 MMBtu/hr auxiliary boiler at the Portland, Oregon GE Carty Plant. This limit of 2.5 lb/MMcf of natural gas (which corresponds to 0.0025 lb/MMBtu) is considered unrealistically low for a guarantee for a boiler of this type. This is because of uncertainty and variability with available PM10/PM2.5 test methods, and the risk of artifact emissions resulting in a tested exceedance. All new natural gas-fired boilers, properly operated, are expected to have intrinsically low PM10/PM2.5 emissions. Another boiler with a low PM10/PM2.5 limit is at the Palmdale Hybrid Power facility, with a limit of 0.33 lb/hr, which corresponds to 0.003 lb/MMBtu at full load. However, this lb/hr limit could be met by reducing the boiler load, if the actual emissions exceed 0.003 lb/MMBtu. The other PM10/PM2.5 BACT precedents range from 0.005 – 0.018 lb/MMBtu. The proposed BACT limit for PM10/PM2.5 for the Facility's auxiliary boiler on gas of 0.008 lb/MMBtu is consistent with this range of the precedents in Table C-7. For ULSD, the proposed BACT limit of 0.06 lb/MMBtu (for filterable plus condensable PM) is set at twice the 40 CFR 63 Subpart JJJJJJ limit of 0.03 lb/MMBtu for filterable PM only. This proposed BACT of 0.06 lb/MMBtu is also more stringent than the single oil-fired auxiliary boiler precedent identified in Table C-7.

For SO2, the proposed BACT limit for gas is 0.0014 lb/MMBtu, consistent with the use of natural gas with a sulfur content of 0.5 grains/100 scf consistent with USEPA's definition of pipeline natural gas. For ULSD, the proposed BACT limit for SO2 is 0.0015 lb/MMBtu.

For H2SO4, the most stringent level of control identified is 0.0001 lb/MMBtu, for a 66.2 MMBtu/hr auxiliary boiler at the Newark Hess project in New Jersey. This is essentially the same rate as approved for the Oregon Clean Energy project in Ohio, of 0.00011 lb/MMBtu. Other H2SO4 rates, when specified, range up to 0.055 lb/MMBtu. The proposed BACT limit for H2SO4 for the Facility's auxiliary boiler of 0.00011 lb/MMBtu (both gas and ULSD) matches the approved rate for the Oregon, Ohio project.

For GHG, most auxiliary boilers have just a mass emission limit specified, based on annual gas use. One unit has a limit of 119 lb CO2e/MMBtu, and one unit has a boiler efficiency specified of 80 percent. The proposed BACT limit for GHG for the Facility's auxiliary boiler for gas is 119 lb CO2e/MMBtu, which also matches the approved rate for the Carroll County Energy project in Ohio. The proposed CO2e BACT for ULSD is 160 lb/MMBtu.

These limits are consistent with the majority of recently permitted projects. There are no GHG BACT precedents for ULSD for auxiliary boilers; the proposed GHG BACT for ULSD is based on the carbon content of the fuel.

Emergency Diesel Generator – BACT Analysis

This section presents the PSD BACT analysis for the emergency diesel generator. The Facility is subject to PSD review for NOx, VOC, CO, PM10/PM2.5, SO2, H2SO4, and GHG, and thus the emergency diesel generator is subject to PSD BACT for these pollutants. The Facility includes a 2,000-kW electric (2,198-kW mechanical), or 2,947-hp emergency diesel generator engine that will have ULSD as the only fuel of use. This emergency diesel generator will be permitted for a maximum of 500 hours per year of operation.

Since the emergency diesel generator is a small, limited-use emission source compared to the combined cycle gas turbine units, the BACT evaluation combines the various pollutants into a single discussion.

Identification of Control Options

The ranking of technically feasible control technologies identified for diesel generators are as follows:

SCR: SCR systems are offered for diesel generators and provide the most stringent level of NOx control available.

Oxidation Catalyst: Oxidation catalyst systems are offered for diesel generators and provide the most stringent level of control available for CO/VOC emissions.

Diesel Particulate Filter: Post-combustion devices similar to oxidation catalysts are also offered for diesel generators, known as diesel particulate filters (DPFs). This is the most stringent level of control for diesel particulates.

Combustion Controls: Diesel engine vendors provide engine combustion designs which meet the federal off-road standards known as “Tier 2” standards for new engines >560 kW.

Low Emitting Fuels: ULSD is normally used for emergency generators since a fuel supply stored in a tank onsite can always be assured for emergency use.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for combined cycle gas turbine emergency generator BACT/LAER determinations is presented in Appendix C, Table C-8.

The most stringent level of control identified is for a natural gas-fired emergency generator, which is at the Avenal Power Center project in California. This emergency generator has SCR to control NOx down to 1.0 gram per brake hp-hour. This is very unusual for a power plant emergency generator, since most projects consider it very important to have a fuel source on-site for an emergency generator. The Avenal project, approved in 2011, has not been constructed. All other emergency generators in Table C-8 do not have any post-combustion controls for PSD pollutants.

Most of the emergency generators in Table C-8 have BACT specified as compliance with the 40 CFR 60 Subpart IIII limits, as is proposed for the Facility. The Moxie projects in Pennsylvania have NOx/VOC/CO/PM BACT limits specified at less than the Subpart IIII limits, but the basis for how this will be accomplished is not clear. For H2SO4, the Facility’s proposed limit of 0.000132 g/kW-hr is as or more stringent than any other energy or output based limit.

For GHG, most emergency generators have just a mass emission limit specified, based on ULSD. The proposed BACT limit for GHG for the Facility’s emergency generator is 858 tpy of CO2e.

Emergency Diesel Fire Pump – BACT Analysis

This section presents the PSD BACT analysis for the emergency diesel fire pump. The Facility is subject to PSD review for NOx, VOC, CO, PM10/PM2.5, H2SO4, and GHG, and thus the emergency diesel fire pump is subject to PSD BACT for these pollutants. The Facility includes a 311-hp emergency diesel engine that will have ULSD as the only fuel of use. This emergency diesel fire pump will be permitted for a maximum of 500 hours per year of operation.

Since the emergency diesel fire pump is a small, limited use emission source compared to the combined cycle gas turbine units, the BACT evaluation combines the various pollutants into a single discussion.

Identification of Control Options

The ranking of technically feasible control technologies identified for diesel engines are as follows:

SCR: SCR systems are offered for diesel engines and provide the most stringent level of NOx control available.

Oxidation Catalyst: Oxidation catalyst systems are offered for diesel engines and provide the most stringent level of control available for CO/VOC emissions.

Diesel Particulate Filter: Post-combustion devices similar to oxidation catalysts are also offered for diesel engines, known as DPFs. This is the most stringent level of control for diesel particulates.

Combustion Controls: Diesel engine vendors provide engine combustion designs which meet the federal off-road standards known as "Tier 3" standards for new engines in the size range typically used for fire pumps.

Low Emitting Fuels: ULSD is normally used for emergency engines since a fuel supply stored in a tank onsite can always be assured for emergency use.

Search of RBLC Determinations

The results of the search of the RBLC and other available permits for combined cycle gas turbine emergency fire pump BACT/LAER determinations are presented in Appendix C, Table C-9.

Most of the emergency fire pumps in Table C-9 have BACT specified as compliance with the 40 CFR 60 Subpart IIII limits, as is proposed for the Facility. None of the emergency fire pump engines in Table C-9 have any post combustion controls for PSD pollutants. The Moxie projects in Pennsylvania have proposed NOx/VOC/CO/PM BACT limits specified at less than the Subpart IIII limits. Also, Brockton Power Company in Massachusetts has proposed a very low PM limit, much lower than the Subpart IIII requirements. The basis for how these limits will be achieved is not clear.

For H2SO4, the Facility's proposed limit of 0.000132 g/kW-hr is as or more stringent than any other energy or output based limit.

For GHG, most emergency generators have just a mass emission limit specified, based on ULSD. The proposed BACT limit for GHG for the Facility's emergency fire pump is 90 tpy of CO2e.

Other Ancillary Sources

There are several other smaller sources associated with the Facility that have the potential to emit PSD pollutants. These include fugitive releases from the natural gas pipelines, SF_6 releases from circuit breakers, and particulate emission from the cooling towers.

Methane is a GHG with a global warming potential of 25 times that of CO_2. There is the potential for minor fugitive leaks of methane gas from connection points along the natural gas pipeline. These connection points include valves, flanges, and compressors. The Facility will have many of these piping components incorporated into its design. The Facility will implement best management practices and routine monitoring to minimize fugitive leaks from the piping components. While BACT for fugitive emissions has not been included in recent permits, this is consistent with BACT determinations for other projects.

SF_6 is a dielectric fluid used in circuit breakers with a global warming potential of 23,900 times that of CO_2. There is the potential for negligible leakage of SF_6 from circuit breakers and the Facility may have several circuit breakers incorporated into its design. The Facility will use state-of-the-art, enclosed pressure SF_6 circuit breakers with leak detection, which is consistent with BACT for other similar projects.

The cooling towers will use high-efficiency drift eliminators to limit drift to no more than 0.0005 percent of the circulating water flow. This is consistent with BACT for other cooling towers.

SUMMARY OF BACT EVALUATIONS

The following tables summarize the proposed emission limits and associated control technology for the facility.

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Combustion Turbines

Pollutant	Case	Emission Rate (lb/MMBtu)	Emission Rate (ppmvdc)	Control Technology
NO_x	CTG Only on Gas CTG Gas with DB CTG on ULSD	0.0075 0.0075 0.0198	2.0 2.0 5.0	DLN, water injection and SCR
VOC	CTG Only on Gas CTG Gas with DB CTG on ULSD	0.0013 0.0026 0.0028	1.0 2.0 2.0	Good combustion controls and oxidation catalyst
CO	CTG Only on Gas CTG Gas with DB CTG on ULSD	0.0046 0.0046 0.0048	2.0 2.0 2.0	Good combustion controls and oxidation catalyst
$PM_{10}/PM_{2.5}$	CTG Only on Gas CTG Gas with DB CTG on ULSD	0.0077 0.0069 0.019	n/a n/a n/a	Good combustion controls and low sulfur fuel
SO_2	CTG Only on Gas CTG Gas with DB CTG on ULSD	0.0014 0.0014 0.0015	n/a n/a n/a	Low sulfur fuel
H_2SO_4	CTG Only on Gas CTG Gas with DB CTG on ULSD	0.0017 0.0017 0.0019	n/a n/a n/a	Low sulfur fuel
GHG	CTG Only on Gas	7,165 Btu/kW-hr (net at full load ISO conditions without duct firing)	n/a	High efficient combustion technology

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Auxiliary Boiler

Pollutant	Emission Rate (lb/MMBtu) (Gas/ULSD)	Control Technology	Represents
NO_x	0.02/0.10	Flue gas recirculation and low NOx burner	BACT/BAT
VOC	0.006	Good combustion controls	BACT/BAT
CO	0.055/0.08	Good combustion controls	BACT/BAT
$PM_{10}/PM_{2.5}$	0.008/0.06	Low sulfur fuel	BACT/BAT
SO_2	0.0014/0.0015	Low sulfur fuel	BACT/BAT
H_2SO_4	0.00011	Low sulfur fuel	BACT/BAT
CO_{2e} (GHG)	119/160	Natural gas/ULSD combustion	BACT/BAT

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Emergency Fire Pump

Pollutant	Emission Rate (g/kW-hr)	Emission Rate (g/hp-hr)	Control Technology	Represents
NO_x	3.5	--	State-of-the-art combustion design	BACT/BAT
VOC	0.5	--	State-of-the-art combustion design	BACT/BAT
CO	3.5	--	State-of-the-art combustion design	BACT/BAT
$PM_{10}/PM_{2.5}$	0.2	0.15	State-of-the-art combustion design	BACT/BAT
SO_2	--	0.006	Low sulfur fuel	BACT/BAT
H_2SO_4	0.000132	--	Low sulfur fuel	BACT/BAT
CO_{2e} (GHG)	90 tpy		Efficient design	BACT/BAT

Summary of Proposed BACT/BAT Emission Limits and Associated Control Technologies for the Emergency Generator

Pollutant	Emission Rate (g/kW-hr)	Emission Rate (g/hp-hr)	Control Technology	Represents
NO_x	5.61	4.2	State-of-the-art combustion design	BACT/BAT
VOC	0.79	0.6	State-of-the-art combustion design	BACT/BAT
CO	3.5	2.6	State-of-the-art combustion design	BACT/BAT
$PM_{10}/PM_{2.5}$	0.2	0.15	State-of-the-art combustion design	BACT/BAT
SO_2	--	0.006	Low sulfur fuel	BACT/BAT
H_2SO_4	0.000132	--	Low sulfur fuel	BACT/BAT
CO_{2e} (GHG)	858 tpy		Efficient design	BACT/BAT

Modeling Review

South Field Energy (SFE)/Tetra Tech has submitted air dispersion modeling for carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter with a diameter equal to or less than 10 microns (PM10), and particulate matter with a diameter equal to or less than 2.5 microns (PM2.5) on behalf of SFE, LLC. SFE is proposing to construct a nominal net 1,150-megawatt (MW) combined cycle gas turbine (CCGT) electric generating facility in 2x2x2 configuration in Columbiana County, OH. SFE has proposed to install two integrated combustion turbine generators (CTG) and two supplementary-fired heat recovery steam generators (HRSG), two mechanical draft cooling towers, and associated ancillary equipment.The ancillary equipment includes one auxiliary boiler which is included in modeling.

Potential emissions from the proposed project are shown to be 236.2 tons per year (tpy) of CO, 320.4 tpy of NOx, 47.3 tpy of SO2, 275.5 tpy of PM10, 268.4 tpy of PM2.5, 103.8 tpy of VOC, 58 tpy of H2SO4, and 4,124,388 tpy of GHGs. The summary of the annual potential emissions and applicable regulatory thresholds are presented in Table 3-1 of the Application (see Application for Prevention of Significant Deterioration Preconstruction Permit-South Field Energy LLC) submitted by SFE/Tetra Tech. Based on the analysis of the potential emissions from the proposed facility, the project triggers Federal Prevention of Significant Deterioration (PSD) review and requires modeling for its emissions of CO, NOx, SO2, PM10, and PM2.5. The proposed facility will also emit air toxics (sulfuric acid, ammonia, formaldehyde, toluene, xylene and acetaldehyde) that exceed the Ohio EPA threshold of one ton per year. Toxics modeling, and a soils and vegetation analysis, have been included. Modeling is not required for greenhouse gases, and a qualitative ozone ambient impact analysis has been included to account for chemical transformation of NOx and VOC to ozone.

SFE has used the AERMOD (version 15181) dispersion model to show compliance for CO, NO_x, SO2, PM10, and PM2.5 with the NAAQS and PSD increments. The facility has also submitted qualitative and qualitative/quantitative (hybrid) analysis of secondary PM2.5 formation potential to show compliance with PM2.5 NAAQS consistent with recent USEPA guidance on PM2.5 permit modeling (USEPA 2014). For air toxics modeling, the facility has used AERMOD to show compliance in accordance with the Ohio EPA's Maximum Allowable Ground Level Concentrations (MAGLC).

Modeling Information

This Project is proposed to be located in Columbiana County, OH. The coordinates of the of the property, represented in the Universal Transverse Mercator (UTM) coordinate system, are approximately 527,120.0 m East, 4,498,339.9 m North in UTM Zone 17 (NAD83).

When modeling, all concentrations were computed in micrograms per cubic meter (μg/m^3). No deposition or depletion was modeled for this case. The latest version of AERMOD model with regulatory default option was selected in the control parameter. Complex terrain and building parameters were considered in the modeling. Terrain elevations were obtained using BEE-Line Software's BEEST program and USGS digital terrain data.

Emissions from two CTG units, two cooling towers, and an auxiliary boiler were included in the modeling for the proposed energy facility. Air dispersion modeling was conducted for multiple operating scenarios including start-up/shutdown to capture worst-case potential impact concentrations. General stack characteristics for the emission sources are shown in Table 5-2, and detailed emission scenarios and the corresponding emission rates for all pollutants are given in Appendix D, Table D-1.

Ground-level concentrations were calculated within Cartesian receptor grids and at receptors placed along the property line to determine the location of the maximum estimated concentration impact. Receptor spacing along the facility fence line was 25m. Receptors were then placed in Cartesian grids extending from the fence line at 50m intervals out to 300m from the fence line; 100m intervals extending from 300m to 1,000m; 500m intervals extending from 1,000m to 5,000m; 1,000m intervals extending from 5,000 to 10,000m; and 2,000m intervals extending from 10,000 to 20,000m. In some cases maximum model concentrations were predicted beyond the dense (50m spacing) grid, and so supplemental receptors have been placed around initial maximum locations at 50m spacing to ensure higher concentrations were not overlooked. A total of 2,566 receptors were considered.

Five years of meteorological data have been used in accordance with the Engineering Guidelines #69 Guideline on Air Quality Models. South Field Energy used five years (i.e., 2010-2014) of surface meteorological data and five years of upper air data from the Pittsburgh International Airport (PIT, WMO# 72520, WBAN# 94823) in the model. The National Weather Service data of the region was determined to be representative of the geographical surroundings of the proposed facility.

RESULTS

Class I

The screening procedure described in Federal Land Managers' Air Quality Related Work Group guidance (FLAG 2010) was performed to determine potential worst-case impacts on the nearest Class I areas and determined that no Class I AQRV analysis is needed for the proposed facility.

Class II

PSD Significant Impact Level (SIL)

Ohio EPA analyzed the significant impact of criteria pollutants (SO2, NO2, CO, PM10 and PM2.5), and compared the estimated concentration with the appropriate SIL resulting from the potential emissions. Ohio EPA is in agreement with the maximum modeled concentrations for various averaging periods (1-hr, 3-hr, 8-hr, 24-hr, and annual) found in Table 5-4, which correspond to the worst case operating scenarios for each pollutant, as shown in Appendix F, Table F-1 in the submitted Application (see Application for Prevention of Significant Deterioration Preconstruction Permit- South Field Energy LLC) submitted by SFE. As Table 5-4 shows, the maximum modeled 1-hour NO2 concentration under Start-up/Shutdown conditions, as well as the 24-hour PM2.5 concentration exceeded their respective SILs. For all other modeling scenarios and pollutants, the maximum predicted concentrations were found to be less than their respective SILs and no additional modeling was necessary.

PSD Increment and NAAQS

The maximum modeled 1-hour NO2 concentration exceeded the SIL, and so in order to demonstrate compliance with the NAAQS for NO2, the appropriate 1-hour concentration for NO2 under Startup/Shutdown conditions was added to the ambient background value determined for NO2 for the project site and is well below the NAAQS, as shown in Table 5-5. PM2.5 cumulative modeling was required to demonstrate NAAQS and PSD increment compliance, as detailed below. However, no additional PM2.5 PSD increment consuming sources were identified, therefore PSD increment compliance is demonstrated for the Facility alone based on the results shown in Table 5-4. The facility impact concentration of is well below the PSD Class II increment for 24-hour PM2.5 concentrations. Ohio EPA has analyzed these results and is in agreement.

PM2.5 Cumulative Modeling Analysis

Since the 24-hr maximum modeled concentration of PM2.5 exceeded the SIL, a cumulative modeling analysis with additional sources in the region has been performed to demonstrate compliance with the NAAQS and PSD increments. 26 emission source units located at 5 facilities were identified for inclusion in the cumulative PM2.5 NAAQS modeling assessment. As shown in Table 5-6, the Cumulative Impact Concentration from the project and additional regional sources is still below the NAAQS when added to the ambient background concentration for PM2.5. Ohio EPA is in agreement that the NAAQS will not be exceeded.

Secondary PM2.5 Formation Analysis

Pursuant to recent guidance issued by USEPA on PM2.5 permit modeling (USEPA 2014) in a NAAQS compliance demonstration under the PSD program, SFE Project submitted an analysis of secondary PM2.5 formation based on the increase in SO2 and NOx emissions from the facility. Per this guidance, secondary PM2.5 can be assessed for this facility by either a qualitative, hybrid qualitative/quantitative, or full quantitative approach. SFE performed both a qualitative and a hybrid qualitative/quantitative assessment. Ohio EPA is in agreement that secondary PM2.5 formation will neither consume additional PSD increments nor cause a violation of the 24-hour and annual PM2.5 NAAQS.

Air Toxic Modeling

After reviewing the modeling analysis of air toxics (sulfuric acid, ammonia, formaldehyde, toluene, xylene, and acetaldehyde) for the proposed installation, the Ohio EPA found no exceedances of the MAGLCs of these air toxics. The Ohio EPA is in agreement with the modeled maximum 1-hr ground level concentrations of above air toxics presented in Table 5-10 in the document - Application for Prevention of Significant Deterioration Preconstruction Permit, South Field Energy LLC submitted by SFE/Tetra Tech.

Soils and Vegetation Analysis

Modeling was performed to assess potential impacts of the SFE project on soils and vegetation. Tables 6-2 through 6-5 show the facility impact concentrations compared to vegetation sensitivity thresholds and NAAQS secondary standards. Table 6-6 shows that project impacts on soils will all be well below the appropriate Soil Screening Criteria. No adverse impact upon soils or vegetation is expected. The modeled concentrations are below the primary and secondary NAAQS limits. Modeling analyses shows that the proposed installation of SFE Project will not cause or contribute significantly to a violation of the NAAQS criteria pollutants.

Conclusion

Based upon the review of the permit to install application and the supporting documentation provided by the applicant, the Ohio EPA staff has determined the proposed installation will comply with all applicable State and Federal environmental regulations and the requirements for BACT are satisfied. Therefore, the Ohio EPA staff recommends a permit to install be issued to SFE for the proposed installation.

PUBLIC NOTICE

The following matters are the subject of this public notice by the Ohio Environmental Protection Agency. The complete public notice, including any additional instructions for submitting comments, requesting information, a public hearing, or filing an appeal may be obtained at:http://epa.ohio.gov/actions.aspx or Hearing Clerk, Ohio EPA, 50 W. Town St., Columbus, Ohio 43215. Ph: 614-644-2129 email:HClerk@epa.ohio.gov

Draft Air Pollution Permit-to-Install Initial Installation
South Field Energy LLC
43610 Hibbetts Mill Rd,, Wellsville, OH 43968
ID#:P0119495
Date of Action: 5/19/2016
Permit Desc:Permit-to-install for the construction of the South Field Energy facility, a nominal 1,150 megawatt (MW) combined cycle gas turbine (CCGT) facility to be located in Wellsville, Ohio..
The permit and complete instructions for requesting information or submitting comments may be obtained at: http://epa.ohio.gov/dapc/permitsonline.aspx by entering the ID # or: Corey Kurjian, Ohio EPA DAPC, Northeast District Office, 2110 East Aurora Road, Twinsburg, OH 44087. Ph: (330)963-1200

Ohio Environmental Protection Agency

DRAFT

Division of Air Pollution Control
Permit-to-Install

for

South Field Energy LLC

Facility ID:	0215132003
Permit Number:	P0119495
Permit Type:	Initial Installation
Issued:	5/19/2016
Effective:	To be entered upon final issuance

Ohio Environmental Protection Agency

Division of Air Pollution Control
Permit-to-Install
for
South Field Energy LLC

Table of Contents

Authorization

Facility ID:	0215132003
Facility Description:	1150 MW combined-cycle gas turbine (CCGT) facility
Application Number(s):	A0054159
Permit Number:	P0119495
Permit Description:	Permit-to-install for the construction of the South Field Energy facility, a nominal 1,150 megawatt (MW) combined cycle gas turbine (CCGT) facility to be located in Wellsville, Ohio.
Permit Type:	Initial Installation
Permit Fee:	$5,025.00*DO NOT send payment at this time, subject to change before final issuance*
Issue Date:	5/19/2016
Effective Date:	To be entered upon final issuance

This document constitutes issuance to:

South Field Energy LLC
43610 Hibbetts Mill Rd
Wellsville, OH 43968

of a Permit-to-Install for the emissions unit(s) identified on the following page.

Ohio Environmental Protection Agency (EPA) District Office or local air agency responsible for processing and administering your permit:

Ohio EPA DAPC, Northeast District Office
2110 East Aurora Road
Twinsburg, OH 44087
(330)963-1200

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

This permit is granted subject to the conditions attached hereto.

Ohio Environmental Protection Agency

Craig W. Butler
Director

Authorization (continued)

Permit Number: P0119495
Permit Description: Permit-to-install for the construction of the South Field Energy facility, a nominal 1,150 megawatt (MW) combined cycle gas turbine (CCGT) facility to be located in Wellsville, Ohio.

Permits for the following Emissions Unit(s) or groups of Emissions Units are in this document as indicated below:

Emissions Unit ID:	**B001**
Company Equipment ID:	Auxiliary Boiler
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P001**
Company Equipment ID:	CTG #1
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P002**
Company Equipment ID:	CTG #2
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P003**
Company Equipment ID:	Emergency Generator
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P004**
Company Equipment ID:	Emergency Fire Pump
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P005**
Company Equipment ID:	Wet Cooling Tower #1
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable
Emissions Unit ID:	**P006**
Company Equipment ID:	Wet Cooling Tower #2
Superseded Permit Number:	
General Permit Category and Type:	Not Applicable

A. Standard Terms and Conditions

1. **Federally Enforceable Standard Terms and Conditions**

   a) All Standard Terms and Conditions are federally enforceable, with the exception of those listed below which are enforceable under State law only:

      (1) Standard Term and Condition A.2.a), Severability Clause

      (2) Standard Term and Condition A.3.c) through A. 3.e)General Requirements

      (3) Standard Term and Condition A.6.c) and A. 6.d), Compliance Requirements

      (4) Standard Term and Condition A.9., Reporting Requirements

      (5) Standard Term and Condition A.10., Applicability

      (6) Standard Term and Condition A.11.b) through A.11.e), Construction of New Source(s) and Authorization to Install

      (7) Standard Term and Condition A.14., Public Disclosure

      (8) Standard Term and Condition A.15., Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

      (9) Standard Term and Condition A.16., Fees

      (10) Standard Term and Condition A.17., Permit Transfers

2. **Severability Clause**

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

   b) All terms and conditions designated in parts B and C of this permit are federally enforceable as a practical matter, if they are required under the Act, or any of its applicable requirements, including relevant provisions designed to limit the potential to emit of a source, are enforceable by the Administrator of the U.S. EPA and the State and by citizens (to the extent allowed by section 304 of the Act) under the Act. Terms and conditions in parts B and C of this permit shall not be federally enforceable and shall be enforceable under State law only, only if specifically identified in this permit as such.

3. **General Requirements**

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

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

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

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

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

4. Monitoring and Related Record Keeping and Reporting Requirements

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

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

(2) The date(s) analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of such analyses.

(6) The operating conditions existing at the time of sampling or measurement.

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

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

(1) Reports of any required monitoring and/or recordkeeping of federally enforceable information shall be submitted to the Ohio EPA DAPC, Northeast District Office.

(2) Quarterly written reports of (i) any deviations from federally enforceable emissionlimitations, operationalrestrictions, andcontroldeviceoperatingparameterlimitations, excluding deviations resulting from malfunctions reported in accordance with OAC rule 3745-15-06, that have been detected by the testing, monitoring and recordkeeping requirements specified in this permit, (ii) the probable cause of such deviations, and (iii) any corrective actions or preventive measures taken, shall be made to the Ohio EPA DAPC, Northeast District Office. The written reports shall be submitted quarterly, by January 31, April 30, July 31, and October 31 of each year and shall cover the previous calendar quarters. See A.15. below if no deviations occurred during the quarter.

(3) Written reports, which identify any deviations from the federally enforceable monitoring, recordkeeping, andreportingrequirements contained in this permit shall be submitted to the Ohio EPA DAPC, Northeast District Office every six months, by January 31 and July 31 of each year for the previous six calendar months. If no deviations occurred during a six-month period, the permittee shall submit a semi-annual report, which states that no deviations occurred during that period.

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

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

5. Scheduled Maintenance/Malfunction Reporting

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

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

6. Compliance Requirements

a) All applications, notifications or reports required by terms and conditions in this permit to be submitted or "reported in writing" are to be submitted to Ohio EPA through the Ohio EPA's eBusiness Center: Air Services web service ("Air Services"). Ohio EPA will accept hard copy submittals on an as-needed basis if the permittee cannot submit the required documents through the Ohio EPA eBusiness Center. In the event of an alternative hard copy submission in lieu of the eBusiness Center, the post-marked date or the date the document is delivered in person will be recognized as the date submitted. Electronic submission of applications, notifications or reports required to be submitted to Ohio EPA fulfills the requirement to submit the required information to the Director, the appropriate Ohio EPA District Office or contracted local air agency, and/or any other individual or organization specifically identified as an additional recipient identified in this permit unless otherwise specified. Consistent with OAC rule 3745-15-03, the electronic signature date shall constitute the date that the required application, notification or report is considered to be "submitted". Any document requiring signature may be represented by entry of the personal identification number (PIN) by responsible official as part of the electronic submission process or by the scanned attestation document signed by the Authorized Representative that is attached to the electronically submitted written report.

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

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

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

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

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

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

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

(1) Dates for achieving the activities, milestones, or compliance required in any schedule of compliance, and dates when such activities, milestones, or compliance were achieved.

(2) An explanation of why any dates in any schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

7. Best Available Technology

As specified in OAC Rule 3745-31-05, new sources that must employ Best Available Technology (BAT) shall comply with the Applicable Emission Limitations/Control Measures identified as BAT for each subject emissions unit.

8. **Air Pollution Nuisance**

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

9. **Reporting Requirements**

The permittee shall submit required reports in the following manner:

a) Reports of any required monitoring and/or recordkeeping of state-only enforceable information shall be submitted to the Ohio EPA DAPC, Northeast District Office.

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

10. **Applicability**

This Permit-to-Install is applicable only to the emissions unit(s) identified in the Permit-to-Install. Separate application must be made to the Director for the installation or modification of any other emissions unit(s)not exempt from the requirement to obtain a Permit-to-Install.

11. **Construction of New Sources(s) and Authorization to Install**

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

b) If applicable, authorization to install any new emissions unit included in this permit shall terminate within eighteen months of the effective date of the permit if the owner or operator has not undertaken a continuing program of installation or has not entered into a binding contractual obligation to undertake and complete within a reasonable time a continuing program of installation. This deadline may be extended by up to 12 months if application is made to the

Director within a reasonable time before the termination date and the permittee shows good cause for any such extension.

c) The permittee may notify Ohio EPA of any emissions unit that is permanently shut down (i.e., the emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31) by submitting a certification from the authorized official that identifies the date on which the emissions unit was permanently shut down. Authorization to operate the affected emissions unit shall cease upon the date certified by the authorized official that the emissions unit was permanently shut down. At a minimum, notification of permanent shut down shall be made or confirmed by marking the affected emissions unit(s) as "permanently shut down" in "Air Services" along with the date the emissions unit(s) was permanently removed and/or disabled. Submitting the facility profile update electronically will constitute notifying the Director of the permanent shutdown of the affected emissions unit(s).

d) The provisions of this permit shall cease to be enforceable for each affected emissions unit after the date on which an emissions unit is permanently shut down (i.e., emissions unit has been physically removed from service or has been altered in such a way that it can no longer operate without a subsequent "modification" or "installation" as defined in OAC Chapter 3745-31). All records relating to any permanently shutdown emissions unit, generated while the emissions unit was in operation, must be maintained in accordance with law. All reports required by this permit must be submitted for any period an affected emissions unit operated prior to permanent shut down. At a minimum, the permit requirements must be evaluated as part of the reporting requirements identified in this permit covering the last period the emissions unit operated.

Unless otherwise exempted,no emissions unit certified by the responsible official as being permanently shut down may resume operation without first applying for and obtaining a permit pursuant to OAC Chapter 3745-31 and OAC Chapter 3745-77 if the restarted operation is subject to one or more applicable requirements.

e) The permittee shall comply with any residual requirements related to this permit, such as the requirement to submit a deviation report, air fee emission report, or other any reporting required by this permit for the period the operating provisions of this permit were enforceable, or as required by regulation or law. All reports shall be submitted in a form and manner prescribed by the Director. All records relating to this permit must be maintained in accordance with law.

12. Permit-To-Operate Application

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

13. Construction Compliance Certification

The applicant shall identify the following dates in the "Air Services"facility profile for each new emissions unit identified in this permit.

a) Completion of initial installation date shall be enteredupon completion of construction and prior to start-up.

b) Commence operation after installation or latest modification date shall be entered within 90 days after commencing operation of the applicable emissions unit.

14. Public Disclosure

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

15. Additional Reporting Requirements When There Are No Deviations of Federally Enforceable Emission Limitations, Operational Restrictions, or Control Device Operating Parameter Limitations

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

16. Fees

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

17. Permit Transfers

Any transferee of this permit shall assume the responsibilities of the prior permit holder. The new owner must update and submit the ownership information via the "Owner/Contact Change" functionality in "Air Services" once the transfer is legally completed.The change must be submitted through "Air Services" within thirty days of the ownership transfer date.

18. Risk Management Plans

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

19. Title IV Provisions

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

B. Facility-Wide Terms and Conditions

1. All the following facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only:

   a) None.

2. The permittee shall ensure that any emissions unit(s) subject to the Cross State Air Pollution Rule (CSAPR) complies/comply with the requirements of the Ohio Administrative Code (OAC) Chapter 3745-109, which includes submitting timely permit applications.

3. The following emissions unit contained in this permit is subject to 40 CFR Part 60, Subparts A and Dc: B001. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website www.ecfr.gov or by contacting the Ohio EPA Northeast District Office.

4. The following emissions units contained in this permit are subject to 40 CFR Part 60, Subparts A, KKKK and TTTT: P001 and P002. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website www.ecfr.gov or by contacting the Ohio EPA Northeast District Office.

5. The following emissions units contained in this permit are subject to 40 CFR Part 60,Subparts A and IIII: P003 and P004. The complete NSPS requirements, including the NSPS General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website www.ecfr.gov or by contacting the Ohio EPA Northeast District Office.

6. The following emissions units contained in this permit are subject to 40 CFR Part 63, Subparts A and ZZZZ: P003 and P004. The complete MACT requirements, including the MACT General Provisions may be accessed via the internet from the electronic Code of Federal Regulations (e-CFR) website www.ecfr.gov or by contacting the Ohio EPA Northeast District Office.

C. Emissions Unit Terms and Conditions

1. B001, Auxiliary Boiler

Operations, Property and/or Equipment Description:

99 MMBtu/hr dual fuel [natural gas and ultra-low sulfur diesel (ULSD)-fired] boiler with low-NOx burners and flue gas recirculation

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

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

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	See b)(2)a. and b)(2)b.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the $PM_{2.5}$, PM_{10}, SO_2 and VOC emissions from this air contaminant source since the potential to emit is less than 10 tons per year. See b)(2)c.
c.	OAC rules 3745-31-10 through 20 (Prevention of Significant Deterioration of Air Quality)	Carbon monoxide (CO) emissions shall not exceed 7.92 pounds per hour (lbs/hr) and 15.39 tons per rolling, 12-month period. Nitrogen oxides (NO_x) emissions shall not exceed 9.9 lbs/hr and 10.65 tons per rolling, 12-month period. Particulate matter emissions less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) shall not exceed 5.94 lbs/hr and 5.69 tons per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 0.59 lb/hr and

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		1.49 tons per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 0.15 lb/hr and 0.35 ton per rolling, 12-month period. Sulfuric acid mist (H_2SO_4) emissions shall not exceed 0.011 lb/hr and 0.03 ton per rolling, 12-month period. Carbon dioxide equivalent (CO_2e) emissions shall not exceed 32,171 tons per rolling, 12-month period. Visible particulate emissions from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. See b)(2)d. <u>Natural Gas Combustion:</u> CO emissions shall not exceed 0.055 pound per million Btu (lb/MMBtu) of actual heat input. NO_x emissions shall not exceed 0.02 lb/MMBtu of actual heat input. $PM_{10}/PM_{2.5}$ shall not exceed 0.008 lb/MMBtu of actual heat input. SO_2 emissions shall not exceed 0.0014 pound per million Btu (lb/MMBtu) of actual heat input. VOC emissions shall not exceed 0.006 lb/MMBtu of actual heat input. H_2SO_4 emissions shall not exceed 1.1E-04 lb/MMBtu of actual heat input. [1]CO_2e emissions shall not exceed 120 lb/MMBtu of actual heat input. <u>ULSD Combustion:</u>

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		CO emissions shall not exceed 0.08 lb/MMBtu of actual heat input. NO_x emissions shall not exceed 0.1 lb/MMBtu of actual heat input. $PM_{10}/PM_{2.5}$ shall not exceed 0.06 lb/MMBtu of actual heat input. SO_2 emissions shall not exceed 0.0015 lb/MMBtu of actual heat input. VOC emissions shall not exceed 0.006 lb/MMBtu of actual heat input. H_2SO_4 emissions shall not exceed 1.1E-04 lb/MMBtu of actual heat input. [1]CO_2e emissions shall not exceed 160 lb/MMBtu of actual heat input.
d.	OAC rule 3745-31-05(F)	The sulfur content of the diesel fuel burned in this emissions unit shall not exceed 15 ppm or 0.0015% sulfur, by weight. See b)(2)j. through b)(2)l.
e.	OAC rule 3745-17-07(A)	See b)(2)e.
f.	OAC rule 3745-17-10(B)(1)	See b)(2)e.
g.	OAC rule 3745-18-06(D)	When burning No. 2 fuel oil, the emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rule 3745-31-05(F).
h.	OAC rule 3745-110-03(K)(16)	Exemption - see b)(2)m.
i.	40 CFR Part 60, Subpart A (40 CFR 60.1 – 40 CFR 60.19)	See b)(2)f.
j.	40 CFR Part 60, Subpart Dc (40 CFR 60.40c – 40 CFR 60.48c)	See b)(2)e., b)(2)g. and b)(2)h.
k.	40 CFR Part 63, Subpart JJJJJJ (40 CFR 63.11193 – 63.11236)	The permittee is exempt from the area source MACT requirements pursuant to 40 CFR Part 63.11195(e) of Subpart JJJJJJ as long as this emissions unit complies with the following requirements: gas-fired boiler as defined in 63.11237 which states a boiler that primarily burns

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		gas is still considered a gas-fired boiler even if it also burns oil or other liquid fuel during periods of gas curtailment, gas supply emergencies, or for periodic testing not to exceed 48 hours during any calendar year. See b)(2)i.
l.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 40 CFR 63.16)	See b)(2)n.

[1]Rounded factor to account for fuel variation and matches 40 CFR Part 60, Subpart TTTT fuel factors.

(2) Additional Terms and Conditions

a. Compliance with the requirements of this rule for CO, NO_x, $PM_{10}/PM_{2.5}$, SO_2 and VOC emissions includes compliance with the requirements of OAC rules 3745-31-10 through 20.

b. The BAT emission limits apply until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

c. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) as part of the Ohio SIP.

d. The lb/MMBtu and lb/hr emission limitations are based on the emissions unit's potentials to emit. Therefore, no monitoring, record keeping, and reporting requirements are necessary to ensure ongoing compliance with these emission limitations.

e. The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.

f. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

g. This rule does not establish emission limitations for natural gas-fired or ULSD-fired boilers, but does require record keeping of gas usage and the sulfur content of ULSD confirming that the fuel meets the Subpart Dc requirement of 0.5 weight percent sulfur per 40 CFR 60.48c(g).

h. This emissions unit is subject to the applicable provisions of Subpart Dc of the New Source Performance Standards (NSPS) as promulgated by the United

States Environmental Protection Agency, 40 CFR Part 60. The application and enforcement of these standards are delegated to the Ohio EPA. The requirements of 40 CFR Part 60 are also federally enforceable.

i. The permittee shall burn only natural gas except during periods of gas curtailment, natural gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

j. The maximum annual operating hours for this emissions unit shall not exceed 5,000 hours per rolling, 12-month period.

k. The maximum annual operating hours for this emissions unit shall not exceed 1,440 hours per rolling, 12-month period when burning ULSD fuel.

l. The quality of the diesel fuel burned in this emissions unit shall meet the following specifications on an "as received" basis:

i. a sulfur content which is sufficient to comply with the allowable SO_2 emission limitation of 0.0015 pound SO_2/MMBtu actual heat input; and 15 ppm sulfur or 0.0015% sulfur by weight.

Compliance with the above-mentioned specifications shall be determined by using the analytical results provided by the permittee or oil supplier for each shipment of oil.

m. The permittee is exempt from the requirements of OAC rule 3745-110-03(A) through (G) since this permit restricts NO_x emissions from this emissions unit to less than 25 tons per year.

n. Table 8 to Subpart JJJJJJ of 40 CFR Part 63 – Applicability of General Provisions to Subpart JJJJJJ shows which parts of the General Provisions in 40 CFR 63.1 - 63.16 apply.

c) Operational Restrictions

(1) The permittee shall burn only natural gas and/or ULSD fuel in this emissions unit.

d) Monitoring and/or Recordkeeping Requirements

(1) For each shipment of ULSD fuel received for burning in this emissions unit, the permittee shall maintain records of the oil supplier's (or permittee's) analyses for sulfur content in parts per million (40 CFR 80.510). The permittee shall perform or require the supplier to perform the analyses for sulfur content in accordance with 40 CFR 80.585.

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

(3) The permittee shall maintain monthly records of the following information:

a. the operating hours for each month;

b. the type of fuel combusted during operation; and

c. the rolling, 12-month summation of the monthly operating time, in hours (including each fuel that was combusted).

(4) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c-48c).

(5) When combusting ULSD fuel, the permittee shall perform daily checks, when the emissions unit is in operation and when the weather conditions allow, for any visible particulate emissions from the stack serving this emissions unit. The presence or absence of any visible emissions shall be noted in an operations log. If visible emissions are observed, the permittee shall also note the following in the operations log:

a. the color of the emissions;

b. whether the emissions are representative of normal operations;

c. if the emissions are not representative of normal operations, the cause of the abnormal emissions;

d. the total duration of any visible emissions incident; and

e. any corrective actions taken to minimize or eliminate the visible emissions.

If visible emissions are present, a visible emissions incident has occurred. The observer does not have to document the exact start and end times for the visible emissions incident under item (d) above or continue the daily check until the incident has ended. The observer may indicate that the visible emissions incident was continuous during the observation period (or, if known, continuous during the operation of the emissions unit). With respect to the documentation of corrective actions, the observer may indicate that no corrective actions were taken if the visible emissions were representative of normal operations, or specify the minor corrective actions that were taken to ensure that the emissions unit continued to operate under normal conditions, or specify the corrective actions that were taken to eliminate abnormal visible emissions.

(6) The operations log required in d)(5) above shall be maintained on site.

e) Reporting Requirements

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

(2) Pursuant to 40 CFR Part 60.7 and 60.48c(a), the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. construction date (no later than 30 days after such date);

b. actual start-up date (within 15 days after such date); and

c. the design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. all exceedances of the rolling, 12-month limitation on the hours of operation for this emissions unit and the limitation on the hours when burning ULSD fuel; and

b. each shipment of ultra low sulfur diesel fuel received for burning in this emissions unit which did not comply with the standards specified in b)(2)l.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(4) See 40 CFR Part 60, Subpart Dc (40 CFR 60.40c-48c).

(5) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 0.055 lb/MMBtu of actual heat input (natural gas), 0.08 lb/MMBtu of actual heat input (ULSD), 7.92 lbs/hr and 15.39 tons per rolling, 12-month period.

Applicable Compliance Method:

The lb/MMBtu emission limitations are based on BACT/LAER Precedents for Auxiliary Boilers provided in the permit application. The hourly emission limitation was developed by multiplying the maximum heat input (99 MMBtu/hr) by the worst-case CO emission factor (0.08 lb/MMBtu for ULSD) to determine the hourly emissions.

The annual emission limitation was developed based on the maximum hourly emissions from both natural gas and ULSD (5.45 lbs/hr and 7.92 lbs/hr, respectively) and then calculated in annual pounds for each fuel using maximum total annual operating hours (5,000), assuming the maximum annual operation on ULSD (1,440 hours), with the balance of the hours on natural gas (5,000 hours minus 1,440 hours = 3,560 hours on natural gas) and then dividing the sum of the pounds on each fuel by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the short-term limitation is shown.

Compliance with the short-term emission limitations shall be demonstrated based upon the emission test required in f)(2).

b. Emission Limitation:

NO_x emissions shall not exceed 0.02 lb/MMBtu of actual heat input (natural gas), 0.1 lb/MMBtu of actual heat input (ULSD), 9.90 lbs/hr and 10.65 tons per rolling, 12-month period.

Applicable Compliance Method:

The lb/MMBtu emission limitations are based on BACT/LAER Precedents for Auxiliary Boilers provided in the permit application. The hourly emission limitation was developed by multiplying the maximum heat input (99 MMBtu/hr) by the worst-case NO_x emission factor (0.1 lb/MMBtu for ULSD) to determine the hourly emissions.

The annual emission limitation was developed based on the maximum hourly emissions from both natural gas and ULSD (1.98 lbs/hr and 9.90 lbs/hr, respectively) and then calculated in annual pounds for each fuel using maximum total annual operating hours (5,000), assuming the maximum annual operation on ULSD (1,440 hours), with the balance of the hours on natural gas (5,000 hours minus 1,440 hours = 3,560 hours on natural gas) and then dividing the sum of the pounds on each fuel by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation is shown.

Compliance with the short-term emission limitations shall be demonstrated based upon the emission test required in f)(2).

c. Emission Limitation:

$PM_{10}/PM_{2.5}$ shall not exceed 0.008 lb/MMBtu of actual heat input (natural gas), 0.06 lb/MMBtu of actual heat input (ULSD), 5.94 lbs/hr and 5.69 tons per rolling, 12-month period.

Applicable Compliance Method:

The lb/MMBtu emission limitations are based on BACT/LAER Precedents for Auxiliary Boilers provided in the permit application. The hourly emission limitation was developed by multiplying the maximum heat input (99 MMBtu/hr) by the worst-case $PM_{10}/PM_{2.5}$ emission factor (0.06 lb/MMBtu for ULSD) to determine the hourly emissions.

The annual emission limitation was developed based on the maximum hourly emissions from both natural gas and ULSD (0.79 lb/hr and 5.94 lbs/hr, respectively) and then calculated in annual pounds for each fuel using maximum total annual operating hours (5,000), assuming the maximum annual operation on ULSD (1,440 hours), with the balance of the hours on natural gas (5,000 hours minus 1,440 hours = 3,560 hours on natural gas) and then dividing the sum of the pounds on each fuel by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation is shown.

Compliance with the short-term emission limitations shall be demonstrated based upon the emission test required in f)(2).

d. Emission Limitation:

SO_2 emissions shall not exceed 0.0014 lb/MMBtu of actual heat input (natural gas), 0.0015 lb/MMBtu of actual heat input (ULSD), 0.15 lb/hr and 0.35 ton per rolling, 12-month period.

Applicable Compliance Method:

The lb/MMBtu emission limitations are based on BACT/LAER Precedents for Auxiliary Boilers provided in the permit application. The hourly emission limitation was developed by multiplying the maximum heat input (99 MMBtu/hr) by the worst-case SO_2 emission factor (0.0015 lb/MMBtu for ULSD per AP-42, Table 3.4-1) to determine the hourly emissions.

The annual emission limitation was developed based on the maximum hourly emissions from both natural gas and ULSD (0.14 lb/hr and 0.15 lb/hr, respectively) and then calculated in annual pounds for each fuel using maximum total annual operating hours (5,000), assuming the maximum annual operation on ULSD (1,440 hours), with the balance of the hours on natural gas (5,000 hours minus 1,440 hours = 3,560 hours on natural gas) and then dividing the sum of the pounds on each fuel by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation is shown.

If required, the permittee shall demonstrate compliance with the lb/MMBtu and hourly emission limitation using Methods 1 thru 4 and 6C of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

e. Emission Limitation:

VOC emissions shall not exceed 0.006 lb/MMBtu of actual heat input for both natural gas and ULSD, 0.59 lb/hr and 1.49 tons per rolling, 12-month period.

Applicable Compliance Method:

The lb/MMBtu emission limitations are based on BACT/LAER Precedents for Auxiliary Boilers provided in the permit application. The hourly emission limitation was developed by multiplying the maximum heat input (99 MMBtu/hr) by the VOC emission factor (0.006 lb/MMBtu) to determine the hourly emissions.

The annual emission limitation was developed by multiplying the hourly emission limitation (0.59 lb/hr) by the maximum annual operating hours (5,000 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the annual operating hours limitation is shown.

Compliance with the short-term emission limitations shall be demonstrated based upon the emission test required in f)(2).

f. Emission Limitation:

H_2SO_4 emissions shall not exceed 1.1E-04 lb/MMBtu of actual heat input for both natural gas and ULSD, 0.011 lb/hr and 0.03 ton per rolling, 12-month period.

Applicable Compliance Method:

The lb/MMBtu emission limitations are based on BACT/LAER Precedents for Auxiliary Boilers provided in the permit application. The hourly emission limitation was developed by multiplying the maximum heat input (99 MMBtu/hr) by the H_2SO_4 emission factor (1.1E-04 lb/MMBtu) to determine the hourly emissions.

The annual emission limitation was developed by multiplying the hourly emission limitation (0.011 lb/hr) by the maximum annual operating hours (5,000 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the annual operating hours limitation is shown.

If required, the permittee shall demonstrate compliance with the lb/MMBtu and lb/hr emissions limitations using Methods 1 thru 4 and 8 of 40 CFR Part 60, Appendix A.

g. Emission Limitation:

CO_2e emissions shall not exceed 120 lb/MMBtu when burning natural gas and 160 lb/MMBtu when burning ULSD of actual heat input, 32,171 tons per rolling, 12-month period.

Applicable Compliance Method:

The lb/MMBtu emission limitations are based on BACT/LAER Precedents for Auxiliary Boilers provided in the permit application and corrected in subsequent permit comments. The annual emission limitation was established to reflect the potential to emit for this emissions unit by calculating the sum of the calculated emissions based on the maximum total annual operating hours (5,000), assuming the maximum annual operation on ULSD (1,440 hours), with the balance of the hours on natural gas (5,000 hours minus 1,440 hours = 3,560 hours on gas). The natural gas emissions are the product of the maximum natural gas firing rate (99 MMBtu/hr) multiplied by the AP-42 emission factors for CO_2, N_2O, and CH_4 from Table 1.4-2 dated 7/98 (120,000 lb/mmscf, 0.64 lb/mmscf, and 2.3 lb/mmscf, respectively), multiplied by the global warming potentials for CO_2, N_2O, and CH_4 (1, 298, and 25, respectively from Table A-1 to Subpart A of 40 CFR Part 98). Divide by the average heating value used for AP-

42 emission factors in Table 1.-42 dated 7/98 (1,020 Btu/scf), multiply by the annual hours on natural gas (3,560 hrs/yr) and divide by 2,000 pounds per ton.

$$\left(99\frac{mmBtu}{hr}\right)x\left[\left(120{,}000\frac{lb}{mmscf}x(1)\right)+\left((0.64\frac{lb}{mmscf)}(298)\right)+\left(\left(2.3\frac{lb}{mmscf}\right)(25)\right)\right]x\left(\frac{mmscf}{1020mmBtu}\right)\left(3{,}560\frac{hrs}{yr}\right)x\left(\frac{ton}{2{,}000lb}\right)=20{,}775\frac{tons}{yr}$$

The ULSD emissions are the product of the maximum ULSD firing rate (99 MMBtu/hr) multiplied by the AP-42 emission factors for CO_2, N_2O, and CH_4 from Tables 1.3-12, 1.3-8 and 1.3-3 respectively dated 7/98 (22,300 lb/Mgal, 0.26 lb/Mgal, and 0.216 lb/Mgal, respectively), multiplied by the global warming potentials for CO_2, N_2O, and CH_4 (1, 298, and 25, respectively from Table A-1 to Subpart A of 40 CFR Part 98). Divide by the average heating value used for AP-42 emission factors in Section 1.3 dated 7/98 (140 MMBtu/Mgal), multiply by the maximum annual hours of operation on ULSD (1,440 hrs/yr) and divide by 2,000 pounds per ton.

$$\left(99\frac{mmBtu}{hr}\right)x\left[\left(22{,}300\frac{lb}{Mgal}x(1)\right)+\left((0.26\frac{lb}{Mgal}(298)\right)+\left(\left(0.216\frac{lb}{Mgal}\right)(25)\right)\right]x\left(\frac{Mgal}{140\ mmBtu}\right)\left(1{,}440\frac{hrs}{yr}\right)x\left(\frac{ton}{2{,}000lb}\right)=11{,}396\ \frac{tons}{yr}$$

$$Total\frac{tons}{year}=20{,}775+\ 11{,}396=32{,}171\ \frac{tons}{yr}$$

Since the CO_2e emissions are estimated to consist of more than 99% CO_2, compliance with this emission limitation shall be determined by comparing the actual annual auxiliary boiler CO2 emissions to the following annual standard:

$$\left(99\frac{mmBtu}{hr}\right)x\left[\left(3560\ hours\ on\ gas\right)(117.65\frac{lb}{MMBtu}\right)+\left(1440\ hours\ on\ ULSD\right)(159.29\frac{lb}{MMBtu}\right)\Big]/(2000\frac{lb}{ton})=32{,}086\ \frac{tons}{yr}$$

If required, the permittee shall conduct emissions testing using Methods 1, 2, 3A and 4 of 40 CFR Part 60, Appendix A to determine the lb/scf CO_2 emission rate. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

h. Emission Limitation:

Visible particulate emissions from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average.

Applicable Compliance Method:

If required, compliance with the stack visible particulate emission limitation shall be demonstrated through visible emission observations performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9.

i. Emission Limitation:

The sulfur content of the ULSD fuel burned in this emissions unit shall not exceed 15 ppm or 0.0015% sulfur, by weight.

Applicable Compliance Method:

Compliance shall be demonstrated based upon the record keeping requirements specified in d)(1).

(2) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of the emissions unit.

b. The emission testing shall be conducted to demonstrate compliance with the following emission limitations:

i. CO emissions in lb/hr and lb/MMBtu;

ii. NO_x emissions in lb/hr and lb/MMBtu;

iii. VOC emissions in lb/hr and lb/MMBtu; and

iv. $PM_{10}/PM_{2.5}$ emissions in lb/hr and lb/MMBtu.

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

for CO, Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A;

for NO_x, Methods 1 thru 4 and 7E of 40 CFR Part 60, Appendix A;

for VOC, Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents; and for $PM_{10}/PM_{2.5}$, Methods 201 or 201A and 202 of 40 CFR Part 51, Appendix M.

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

d. The test(s) shall be conducted under those representative conditions that challenge to the fullest extent possible a facility's ability to meet the applicable emissions limits and/or control requirements, unless otherwise specified or approved by the Ohio EPA Northeast District Office. Although this generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario. Failure to test under these conditions is justification for not accepting the test results as a demonstration of compliance.

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

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

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

g) Miscellaneous Requirements

(1) None.

2. Emissions Unit Group – P001 and P002

Operations, Property and/or Equipment Description:

EU ID	Operations, Property and/or Equipment Description
P001	Combined cycle combustion turbine (3,131 MMBtu/hr heat input turbine at ISO conditions, natural gas firing with evaporative cooler on and 800 MMBtu/hr maximum heat input natural gas-fired duct burner) with dry low NOx combustors, selective catalytic reduction (SCR), catalytic oxidizer, and wet injection for ULSD firing. Heat input for ULSD firing at ISO conditions, with evaporative cooler on is 3,173 MMBtu/hr.
P002	Combined cycle combustion turbine (3,131 MMBtu/hr heat input turbine at ISO conditions, natural gas firing with evaporative cooler on and 800 MMBtu/hr maximum heat input natural gas-fired duct burner) with dry low NOx combustors, selective catalytic reduction (SCR), catalytic oxidizer, and wet injection for ULSD firing. Heat input for ULSD firing at ISO conditions, with evaporative cooler on is 3,173 MMBtu/hr.

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) d)(16), d)(17), d)(18), and d)(219) and e)(5).

b) Applicable Emissions Limitations and/or Control Requirements

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

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) and ORC 3704.03(T)	See b)(2)a. and b)(2)b.
b.	OAC rules 3745-31-10 through 20 (Prevention of Significant Deterioration of Air Quality)	Visible particulate emissions from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average. Facility heat rate shall not exceed 7,165 Btu/net kW-hr energy output (at full load ISO conditions, natural gas firing, without duct firing). <u>Natural Gas:</u> CO_2e emissions shall not exceed 481,301 lbs/hr (maximum under any condition with

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		duct firing). <u>ULSD:</u> CO_2e emissions shall not exceed 546,182 lbs/hr. See b)(2)c. through b)(2)k. and b)(2)s. through b)(2)u.
c.	OAC rule 3745-31-05(F)	The sulfur content of the diesel fuel burned in this emissions unit shall not exceed 15 ppm or 0.0015% sulfur, by weight. See b)(2)f. and b)(2)g.
d.	OAC rule 3745-17-07(A)	See b)(2)l.
e.	OAC rule 3745-17-11(B)(4)	See b)(2)l.
f.	OAC rule 3745-18-06(A)	See b)(2)m.
g.	OAC rule 3745-110-03(K)(18)	Exemption from NO_x RACT requirements
h.	OAC rule 3745-114-01	See d)(15), d)(16), d)(17), d)(18), d)(19) and e)(8).
i.	40 CFR Part 60, Subpart A (40 CFR 60.1 – 40 CFR 60.19)	See b)(2)o.
j.	40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420) [In accordance with 40 CFR 60.4305(a), this emissions unit is a stationary combustion turbine with a heat input at peak load greater than 10 MMBtu/hr with a heat recovery steam generator/duct burners subject to the emissions limitations/control measures specified in this section.]	See b)(2)l. and b)(2)o.
k.	40 CFR Part 60, Subpart TTTT (40 CFR 60.5508 – 60.5580)	CO_2 emissions shall not exceed 450 kg per megawatt-hour (MWh) of gross energy output (1,000 lb CO_2/MWh) or CO_2 emissions shall not exceed 470 kg per MWh of net energy output (1,030 lb CO_2/MWh) See b)(2)o., b)(2)p., d(20) and e)(4).
l.	40 CFR Part 60, Subpart A (40 CFR 60.1 – 60.19)	Table 3 to Subpart TTTT of 40 CFR Part 60 – Applicability of General Provisions to

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		Subpart TTTT shows which parts of the General Provisions in 40 CFR 60.1 - 60.19 apply.
m.	40 CFR Part 63, Subpart YYYY (40 CFR 63.6080 – 63.6175)	See b)(2)q.
n.	40 CFR Part 63, Subpart JJJJJ (40 CFR 63.11193 – 63.11236)	See b)(2)r.

(2) Additional Terms and Conditions

a. All requirements specified in this Section of the permit for Emissions Unit Group P001 and P002 apply to each combined cycle combustion turbine (P001 and P002) unless a combined requirement is otherwise specified.

b. Compliance with the requirements of this rule for CO, SO_2, NO_x, PM_{10}, $PM_{2.5}$ and VOC includes compliance with the requirements of OAC rules 3745-31-10 through 20.

c. The emissions from this emissions unit shall utilize dry low NOx combustors, selective catalytic reduction (SCR), and wet injection for ULSD firing at all times during which the emissions unit is in operation.

d. The PM_{10}/$PM_{2.5}$ emission limitations include both filterable and condensable particulate emissions.

e. The sulfur content of natural gas burned in this emissions unit shall not exceed 0.5 grain per 100 standard cubic feet.

f. The maximum annual operating hours for this emissions unit shall not exceed 1,440 hours per rolling, 12-month period when burning ULSD fuel.

g. The quality of the diesel fuel burned in this emissions unit shall meet the following specifications on an “as received” basis:

i. a sulfur content which is sufficient to comply with the allowable sulfur dioxide emission limitation of 0.0015 pound sulfur dioxide/MMBtu actual heat input; and 15 ppm sulfur or 0.0015% sulfur by weight.

Compliance with the above-mentioned specifications shall be determined by using the analytical results provided by the permittee or oil supplier for each shipment of oil.

h. The permittee shall comply with the following emissions limitations per turbine:

Allowable Emissions				
Pollutant	**Operating Mode**[a]	**Emission Rate** [b,e]	**Emission rate, lb/hr**[b]	**Emission rate, tons per rolling, 12-month period**[f]
CO	CT with DB	2.0[c]	18.57	-
	CT only	2.0[c]	15.17	-
	ULSD	2.0[c]	16.15	
	All operating modes, including startup periods	-	-	108.1
NO_x	CT with DB	2.0[c]	30.51	-
	CT only	2.0[c]	24.92	-
	ULSD	5.0[c]	66.32	
	All operating modes, including startup periods			151.3
SO_2	CT with DB	1.4E-03[d]	5.64	-
	CT only	1.4E-03[d]	4.61	
	ULSD	1.5E-03[d]	5.19	
	All operating modes, including startup periods			23.5
$PM_{10}/PM_{2.5}$	CT with DB	6.9E-03[d]	25.0	-
	CT only	7.7E-03[d]	16.16	
	ULSD	1.9E-02[d]	55.4	
	All operating modes, including startup periods			128.9

Allowable Emissions				
Pollutant	**Operating Mode[a]**	**Emission Rate [b,e]**	**Emission rate, lb/hr[b]**	**Emission rate, tons per rolling, 12-month period[f]**
VOC	CT with DB	2.0[c]	10.64	-
	CT only	1.0[c]	4.35	-
	ULSD	2.0[c]	9.25	
	All operating modes, including startup periods	-	-	50.6
H_2SO_4	CT with DB	1.7E-03[d]	6.96	-
	CT only	1.7E-03[d]	5.65	-
	ULSD	1.9E-03[d]	6.35	
	All operating modes, including startup periods	-	-	29.0
CO_2e	All operating modes, including startup periods	-	-	2,045,634.5

a. CT = combustion turbine; DB = duct burner

b. Limitation does not apply during periods of startup and shutdown.

c. Parts per million by volume dry (ppmvd) at 15% oxygen.

d. Pounds per million Btu of heat input.

e. Emissions limitations are based on an hourly average.

f. Potential annual emissions from the proposed facility were estimated using the following worst-case assumptions:

- Full-load operation of the combustion turbine generators (CTGs)

Allowable Emissions				
Pollutant	**Operating Mode**[a]	**Emission Rate** [b,e]	**Emission rate, lb/hr**[b]	**Emission rate, tons per rolling, 12-month period**[f]
for 8,760 hours per year (at 59°F ambient temperature), assuming • 1,440 hours per year firing ULSD; • Duct burning for 8,760 hours per year during steady-state operation of each CTG; and • Incorporation of start-up/shutdown events, based on a representative scenario that reflects maximum emissions.				

i. To ensure enforceability of the rolling, 12-month emissions limitations during the first 12 calendar months of operation following the initial emissions compliance testing and CEMS certification, the permittee shall not exceed the emission levels specified in the following table (per turbine):

		Maximum Allowable Cumulative Emissions (Tons)				
Month(s)	CO	NO_x	$PM_{10}/PM_{2.5}$	VOC	SO_2	H_2SO_4
1	18.0	25.2	23.6	8.4	3.9	4.8
1-2	36.0	50.4	47.2	16.9	7.8	9.7
1-3	54.0	75.6	70.8	25.3	11.7	14.5
1-4	72.0	100.8	94.4	33.7	15.6	19.3
1-5	90.0	126.0	118.0	42.1	19.5	24.2
1-6	108.1	151.3	141.7	50.6	23.5	29.0
1-7	108.1	151.3	141.7	50.6	23.5	29.0
1-8	108.1	151.3	141.7	50.6	23.5	29.0
1-9	108.1	151.3	141.7	50.6	23.5	29.0
1-10	108.1	151.3	141.7	50.6	23.5	29.0
1-11	108.1	151.3	141.7	50.6	23.5	29.0

		Maximum Allowable Cumulative Emissions (Tons)				
Month(s)	CO	NO_x	$PM_{10}/PM_{2.5}$	VOC	SO_2	H_2SO_4
1-12	108.1	151.3	141.7	50.6	23.5	29.0

After the first 12 calendar months of operation following the initial emissions compliance testing and CEMS certification, compliance with the annual emissions limitations shall be based upon a rolling, 12-month summation of the monthly emissions.

j. The permittee shall comply with the following requirements during periods of startup and shutdown:

	Natural Gas		**ULSD**	
Pollutant	Start-up (lb/hr)	Shutdown (lb/hr)	Start-up (lb/hr)	Shutdown (lb/hr)
NO_x	231.4	26.5	181.3	85.4
CO	158.3	160.1	356.6	132.3
VOC	21.4	55.2	109.0	41.3

*Represents worst-case hourly emissions as normal start-up and shutdown events will be completed in less than one hour with steady-state emissions balancing out each hour.

**Since cold, warm, and hot starts all have a comparable duration of 20-45 minutes, the worst-case type of start for each pollutant has been utilized to determine a single lb/hr emissions limitation for start-up along with a single emissions limitation for shutdown.

***The emissions data presented does not imply that all start-up events will be completed in one hour. However, the lb/hr emissions limitations for start-up and shutdown are intended to apply to each hour of any start-up or shutdown even if the start-up or shutdown persists longer than one hour due to unusual circumstances.

****The identified pollutants are those that have start-up emissions that are not "self-correcting" on an annual basis for both natural gas and ULSD firing. "Self-correcting" is defined as the emissions for each start-up and shutdown sequence that are less than the corresponding steady-state emission rate, accounting for minimum downtime between shutdowns and start-ups.

k. The design net plant base heat rate shall not exceed 7,165 Btu/kW-hr HHV (ISO conditions without duct firing).

l. The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.

m. The emission limitation specified by this rule is less stringent than the emission limitation established by OAC rule 3745-31-05(F).

n. 40 CFR Part 60, Subpart A provides applicability provisions, definitions, and other general provisions that are pertinent to emissions units affected by 40 CFR Part 60.

o. This emissions unit is subject to the applicable provisions of Subparts KKKK and TTTT of the New Source Performance Standards (NSPS) as promulgated by the United States Environmental Protection Agency, 40 CFR Part 60. The application and enforcement of these standards are delegated to the Ohio EPA. The requirements of 40 CFR Part 60 are also federally enforceable.

p. The permittee shall comply with the applicable restrictions required under 40 CFR Part 60, Subpart TTTT, including the following sections:

60.5525	General Compliance Requirements

q. This emissions unit is not subject to the requirements of 40 CFR Part 63, Subpart YYYY, since it is not located at a major source of HAP emissions.

r. The duct burner is exempt from the requirements of this rule per 40 CFR Part 63, Subpart UUUUU due to combusting only natural gas.

s. Each continuous NO_x monitoring system shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2. At least 45 days before commencing certification testing of the continuous NO_x monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of NO_x emissions from the continuous monitor(s), in units of the applicable standard(s). Except as allowed below, the plan shall follow the requirements of 40 CFR Part 60, Appendix F and 40 CFR Part 75, Appendix B. The quality assurance/quality control plan and a logbook dedicated to the continuous monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct relative accuracy test audits for the continuous NO_x monitoring system in accordance with the frequencies required pursuant to 40 CFR Part 60 and 40 CFR Part 75; or may follow relative accuracy test audit frequency requirements for monitoring systems subject to 40 CFR 75, Appendix B, in lieu of frequencies required in 40 CFR Part 60. In either case, results shall be recorded and reported in units of the applicable standard(s) in accordance with 40 CFR Part 60.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits pursuant to 40 CFR Part 60, and linearity checks pursuant to 40 CFR Part 75; however, linearity checks completed pursuant to 40 CFR Part 75, Appendix B, may be substituted for the quarterly cylinder gas or relative accuracy audits required per 40 CFR Part 60.

t. Each continuous carbon monoxide (CO) monitoring system shall be certified to meet the requirements of 40 CFR Part 60, Appendix B, Performance Specifications 4 or 4a. At least 45 days before commencing certification testing of the continuous CO monitoring system(s), the permittee shall develop and maintain a written quality assurance/quality control plan designed to ensure continuous valid and representative readings of CO emissions from the continuous monitor(s), in units of the applicable standard(s). The fuel flow monitors/meters shall be maintained as required in Part 75, Appendix D. Except as allowed below, the plan shall follow the requirements of 40 CFR Part 60, Appendix F. The quality assurance/quality control plan and a logbook dedicated to the continuous monitoring system must be kept on site and available for inspection during regular office hours.

The plan shall include the requirement to conduct relative accuracy test audits for the continuous CO monitoring system in accordance with the frequencies required for monitoring systems subject to 40 CFR 60, or may follow relative accuracy test audit frequency requirements for monitoring systems subject to 40 CFR 75, Appendix B. In either case, results shall be recorded and reported in units of the applicable standard(s) in accordance with 40 CFR Part 60.

The plan shall include the requirement to conduct quarterly cylinder gas audits or relative accuracy audits as required in 40 CFR Part 60; however, the quarterly cylinder gas audit and relative accuracy audit frequency requirements may be adjusted to coincide with linearity checks completed for continuous emissions monitoring systems subject to 40 CFR Part 75, Appendix B requirements.

u. The continuous emission monitoring system consists of all the equipment used to acquire data to provide a record of emissions and includes the sample extraction and transport hardware, sample conditioning hardware, analyzers, and data recording/processing hardware and software.

c) Operational Restrictions

(1) The permittee shall only burn pipeline quality natural gas as fuel in each duct burner.

(2) The permittee shall burn only natural gas and/or ULSD fuel in each combustion turbine.

(3) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

d) Monitoring and/or Recordkeeping Requirements

(1) For each shipment of ULSD fuel received for burning in this emissions unit, the permittee shall maintain records of the oil supplier's (or permittee's) analyses for sulfur content in parts per million (40 CFR 80.510). The permittee shall perform or require the supplier to perform the analyses for sulfur content in accordance with 40 CFR 80.585.

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

(3) The permittee shall maintain monthly records of the following information:

a. the operating hours for each month;

b. the type of fuel combusted during operation; and

c. the rolling, 12-month summation of the monthly operating time, in hours (including each fuel that was combusted).

(4) When combusting ULSD fuel, the permittee shall perform daily checks, when the emissions unit is in operation and when the weather conditions allow, for any visible particulate emissions from the stack serving this emissions unit. The presence or absence of any visible emissions shall be noted in an operations log. If visible emissions are observed, the permittee shall also note the following in the operations log:

a. the color of the emissions;

b. whether the emissions are representative of normal operations;

c. if the emissions are not representative of normal operations, the cause of the abnormal emissions;

d. the total duration of any visible emissions incident; and

e. any corrective actions taken to minimize or eliminate the visible emissions.

If visible emissions are present, a visible emissions incident has occurred. The observer does not have to document the exact start and end times for the visible emissions incident under item (d) above or continue the daily check until the incident has ended. The observer may indicate that the visible emissions incident was continuous during the observation period (or, if known, continuous during the operation of the emissions unit). With respect to the documentation of corrective actions, the observer may indicate that no corrective actions were taken if the visible emissions were representative of normal operations, or specify the minor corrective actions that were taken to ensure that the emissions unit continued to operate under normal conditions, or specify the corrective actions that were taken to eliminate abnormal visible emissions.

(5) The operations log required in d)(4) above shall be maintained on site.

(6) For purposes of demonstrating compliance with the natural gas sulfur concentration restriction of 0.5 grain/100 scf, the permittee shall sample and analyze the natural gas burned in this emissions unit monthly to determine the sulfur content using the appropriate ASTM or Gas Processors Association standards. Fuel supplier data may be used to comply with this requirement, provided that it is demonstrated to be representative of the fuel received for burning at this emissions unit.

(7) The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine as specified in d)(7), if the fuel is demonstrated not to exceed potential sulfur emissions of 1.4E-03 lb SO_2/MMBtu. The permittee shall use one of the following sources of information to make the required demonstration:

a. the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas is 0.5 grain of sulfur or less per 100 standard cubic feet, has potential sulfur emissions of less than less than 1.4E-03 lb SO_2/MMBtu heat input;

b. representative fuel sampling data which show that the sulfur content of the fuel does not exceed 1.4E-03 lb SO_2/MMBtu heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required; or

c. one of the custom sulfur monitoring schedules outlined in 40 CFR 60.4370(c) may be used to comply with the 1.4E-03 lb SO_2/MMBtu standard.

(8) The permittee shall maintain monthly records of the following information:

a. the CO, NO_x, PM_{10}/$PM_{2.5}$, SO_2, VOC and H_2SO_4 emission rate for each month of operations; and

b. beginning after the first 12 calendar months of operation following the initial emissions compliance testing and CEMS certification, the rolling, 12-month summation of the CO, NO_x, PM_{10}/$PM_{2.5}$, SO_2, VOC and H_2SO_4 emissions.

Also, during the first 12 calendar months of operation following the initial emissions compliance testing and CEMS certification, the permittee shall record the cumulative CO, NO_x, PM_{10}/$PM_{2.5}$, SO_2, VOC and H_2SO_4 emissions for each calendar month.

(9) The permittee shall maintain monthly records of the following information for this emissions unit for purposes of calculating rolling, 12-month emissions:

a. date, time, and duration of each startup and shutdown period;

b. the hours of operation of the combustion turbine;

c. the hours of operation of the duct burner;

d. the total duration of all startup periods in hours per rolling, 12-month period;

e. the total duration of all shutdown periods in hours per rolling, 12-month period;

f. the total duration of steady-state operation without duct burner firing in hours per rolling, 12-month period; and

g. the total duration of steady-state operation with duct burner firing in hours per rolling, 12-month period.

(10) Prior to the installation of the continuous NO_x monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 2. The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous NO_x monitoring system meets the requirements of Performance Specifications 2; and the U.S. EPA shall certify that the continuous NO_x monitoring system meets the requirements under 40 CFR Part 75, which may be approved through the recommendation for certification by Ohio EPA to U.S. EPA. Once received, the letter(s)/document(s) of certification under Part 60 and certification or recommendation for certification under Part 75 shall be maintain on-site and made available to the Director (the Ohio EPA Northeast District Office) upon request.

(11) The permittee shall install, operate, and maintain equipment to continuously monitor and record NO_x emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Part 60 and 40 CFR Part 75.

The permittee shall maintain records of all data obtained by the continuous NO_x monitoring system including, but not limited to:

a. emissions of NO_x in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of NO_x in pounds per hour and in units of the applicable standard(s) in the appropriate averaging period;

c. results of quarterly cylinder gas audits or linearity checks;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous NO_x monitoring system, and control equipment;

g. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous NO_x monitoring system;

h. malfunction of the control equipment and/or the continuous NO_x monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(12) Prior to the installation of the continuous carbon monoxide (CO) monitoring system, the permittee shall submit information detailing the proposed location of the sampling site in accordance with the siting requirements in 40 CFR Part 60, Appendix B, Performance Specification 4 or 4a (as appropriate). The Ohio EPA, Central Office shall approve the proposed sampling site and certify that the continuous CO monitoring system meets the requirements of Performance Specifications 4 or 4a. Once received, the letter(s)/document(s) of certification shall be maintained on-site and shall be made available to the Director (the Ohio EPA Northeast District Office) upon request.

(13) The permittee shall operate and maintain equipment to continuously monitor and record CO emissions from this emissions unit in units of the applicable standard(s). The continuous monitoring and recording equipment shall comply with the requirements specified in 40 CFR Parts 60.

The permittee shall maintain records of all data obtained by the continuous CO monitoring system including, but not limited to:

a. emissions of CO in parts per million for each cycle time of the analyzer, with no resolution less than one data point per minute required;

b. emissions of CO in pounds per hour and in units of the applicable standard(s) in the appropriate averaging period;

c. results of quarterly cylinder gas audits;

d. results of daily zero/span calibration checks and the magnitude of manual calibration adjustments;

e. results of required relative accuracy test audit(s), including results in units of the applicable standard(s);

f. hours of operation of the emissions unit, continuous CO monitoring system, and control equipment;

g. the date, time, and hours of operation of the emissions unit without the control equipment and/or the continuous CO monitoring system;

h. the date, time, and hours of operation of the emissions unit during any malfunction of the control equipment and/or the continuous CO monitoring system; as well as,

i. the reason (if known) and the corrective actions taken (if any) for each such event in (g) and (h).

All valid data points generated and recorded by the continuous emission monitoring and data acquisition and handling system shall be used in the calculation of the pollutant concentration and/or emission rate over the appropriate averaging period.

(14) The permittee shall calculate and record the monthly CO_2 emissions from P001 and P002 using data from the continuous fuel flow monitor using the procedures set forth in 40 CFR Part 75, Appendix G. From this data, the permittee shall calculate the CO_2 emissions from P001 and P002 per rolling, 12-month period.

(15) The Permit to Install application for these emissions units, P001 and P002, was evaluated based on the actual materials and the design parameters of the emissions unit's(s') exhaust system, as specified by the permittee. The "Toxic Air Contaminant Statute", ORC 3704.03(F), was applied to this/these emissions unit(s) for each toxic air contaminant listed in OAC rule 3745-114-01, using data from the permit application; and modeling was performed for each toxic air contaminant(s) emitted at over one ton per year using an air dispersion model such as SCREEN3, AERMOD, or ISCST3, or other Ohio EPA approved model. The predicted 1-hour maximum ground-level concentration result(s) from the approved air dispersion model, was compared to the Maximum Acceptable Ground-Level Concentration (MAGLC), calculated as described in the Ohio EPA guidance document entitled "Review of New Sources of Air Toxic Emissions, Option A", as follows:

a. the exposure limit, expressed as a time-weighted average concentration for a conventional 8-hour workday and a 40-hour workweek, for each toxic compound(s) emitted from the emissions unit(s), (as determined from the raw materials processed and/or coatings or other materials applied) has been documented from one of the following sources and in the following order of preference (TLV was and shall be used, if the chemical is listed):

   i. Threshold Limit Value (TLV) from the American Conference of Governmental Industrial Hygienists (ACGIH) "Threshold Limit Values for Chemical Substances and Physical Agents Biological Exposure Indices"; or

   ii. Short Term Exposure Limit (STEL) or the ceiling value from the American Conference of Governmental Industrial Hygienists (ACGIH) "Threshold Limit Values for Chemical Substances and Physical Agents Biological Exposure Indices"; the STEL or ceiling value is multiplied by 0.737 to convert the 15-minute exposure limit to an equivalent 8-hour TLV.

b. The TLV is divided by ten to adjust the standard from the working population to the general public (TLV/10).

c. This standard is/was then adjusted to account for the duration of the exposure or the operating hours of the emissions unit(s), i.e., "X = 24" hours per day and "Y = 7" days per week, from that of 8 hours per day and 5 days per week. The resulting calculation was (and shall be) used to determine the Maximum Acceptable Ground-Level Concentration (MAGLC):

   TLV/10 x 8/X x 5/Y = 4 TLV/XY = MAGLC

d. The following summarizes the results of dispersion modeling for the "worst case" toxic contaminant(s):

Toxic Contaminant: H_2SO_4

TLV (mg/m3): 0.2 mg/m^3

Hourly Emission Rate for Maximum Hourly Impact (lbs/hr): 6.10

Predicted 1-Hour Maximum Ground-Level Concentration (µg/m3): 1.51

MAGLC (µg/m3): 4.76

The permittee has demonstrated that emissions of H_2SO_4, from emissions unit(s) P001 and P002, is calculated to be less than eighty percent of the MAGLC; any new raw material or processing agent shall not be applied without evaluating each component toxic air contaminant in accordance with the "Toxic Air Contaminant Statute", ORC 3704.03(F).

(16) Prior to making any physical changes to or changes in the method of operation of the emissions unit(s), that could impact the parameters or values that were used in the predicted 1-hour maximum ground-level concentration, the permittee shall re-model the change(s) to demonstrate that the MAGLC has not been exceeded. Changes that can affect the parameters/values used in determining the 1-hour maximum ground-level concentration include, but are not limited to, the following:

a. changes in the composition of the materials used or the use of new materials, that would result in the emission of a new toxic air contaminant with a lower TLV than the lowest TLV previously modeled;

b. changes in the composition of the materials, or use of new materials, that would result in an increase in emissions of any toxic air contaminant listed in OAC rule 3745-114-01, that was modeled from the initial (or last) application; and

c. physical changes to the emissions unit(s) or its/their exhaust parameters (e.g., increased/ decreased exhaust flow, changes in stack height, changes in stack diameter, etc.).

If the permittee determines that the "Toxic Air Contaminant Statute" will be satisfied for the above changes, the Ohio EPA will not consider the change(s) to be a "modification" under OAC rule 3745-31-01 solely due to a non-restrictive change to a parameter or process operation, where compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F), has been documented. If the change(s) meet(s) the definition of a "modification", the permittee shall apply for and obtain a final permit-to-install (PTI) prior to the change. The Director may consider any significant departure from the operations of the emissions unit, described in the permit application, as a modification that results in greater emissions than the emissions rate modeled to determine the ground level concentration; and he/she may require the permittee to submit a permit application for the increased emissions.

(17) The permittee shall collect, record, and retain the following information for each toxic evaluation conducted to determine compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F):

a. a description of the parameters/values used in each compliance demonstration and the parameters or values changed for any re-evaluation of the toxic(s) modeled (the composition of materials, new toxic contaminants emitted, change in stack/exhaust parameters, etc.);

b. the MAGLC for each significant toxic contaminant or worst-case contaminant, calculated in accordance with the "Toxic Air Contaminant Statute", ORC 3704.03(F);

c. a copy of the computer model run(s), that established the predicted 1-hour maximum ground-level concentration that demonstrated the emissions unit(s) to be in compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F), initially and for each change that requires re-evaluation of the toxic air contaminant emissions; and

d. the documentation of the initial evaluation of compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F), and documentation of any determination that was conducted to re-evaluate compliance due to a change made to the emissions unit(s) or the materials applied.

(18) The permittee shall maintain a record of any change made to a parameter or value used in the dispersion model, used to demonstrate compliance with the "Toxic Air Contaminant Statute", ORC 3704.03(F), through the predicted 1-hour maximum ground-level concentration. The record shall include the date and reason(s) for the change and if the change would increase the ground-level concentration.

(19) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

(20) The permittee shall comply with the applicable restrictions required under 40 CFR Part 60, Subpart TTTT, including the following sections:

60.5535	Monitor and Collect Data to Demonstrate Compliance
60.5540	Demonstrate Compliance with CO_2 Emissions and Determine Excess Emissions
60.5550	Notification Requirements
60.5560 and 60.5565	Record Keeping Requirements

e) Reporting Requirements

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

(2) Pursuant to 40 CFR Part 60.7 and 60.48c(a), the permittee is hereby advised of the requirement to report the following at the appropriate times:

a. construction date (no later than 30 days after such date);

b. actual start-up date (within 15 days after such date); and

c. the design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(3) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. all exceedances of the rolling, 12-month limitation on the hours of operation for this emissions unit and the limitation on the hours when burning ULSD fuel;

b. each shipment of ULSD fuel received for burning in this emissions unit which did not comply with the standards specified in b)(2)g; and

c. any monthly record showing an exceedance of the allowable sulfur content of natural gas, 0.5 grain per 100 standard cubic feet.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(4) The permittee shall comply with the applicable restrictions required under 40 CFR Part 60, Subpart TTTT, including the following sections:

60.5555	Required Reports

(5) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous NO_x monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA Northeast District Office, documenting all instances of NO_x emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, 40 CFR Parts 75 and 76, OAC Chapters 3745-14 and 3745-23, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous NO_x and other associated monitors;

iii. a description of any change in the equipment that comprises the CEMS, including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the EER*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total NO_x emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous NO_x monitoring system while the emissions unit was in operation;

viii. results and date of quarterly cylinder gas audits or linearity checks;

ix. unless previously submitted, results and date of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous NO_x monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous NO_x monitoring system, emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous NO_x monitoring system and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter. Data substitution procedures from 40 CFR 75 are not to be used for showing compliance with the short term OAC 3745-31-05(A)(3) rule-based or NSPS-based limitation(s) in this permit.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(6) The permittee shall comply with the following quarterly reporting requirements for the emissions unit and its continuous CO monitoring system:

a. Pursuant to the monitoring, record keeping, and reporting requirements for continuous monitoring systems contained in 40 CFR 60.7 and 60.13(h) and the requirements established in this permit, the permittee shall submit reports within 30 days following the end of each calendar quarter to the Ohio EPA Northeast District Office, documenting all instances of CO emissions in excess of any applicable limit specified in this permit, 40 CFR Part 60, OAC Chapter 3745-21, and any other applicable rules or regulations. The report shall document the date, commencement and completion times, duration, and magnitude of each exceedance, as well as, the reason (if known) and the corrective actions taken (if any) for each exceedance. Excess emissions shall be reported in units of the applicable standard(s).

b. These quarterly reports shall be submitted by January 30, April 30, July 30, and October 30 of each year and shall include the following:

i. the facility name and address;

ii. the manufacturer and model number of the continuous CO and other associated monitors;

iii. a description of any change in the equipment that comprises the continuous emission monitoring system (CEMS), including any change to the hardware, changes to the software that may affect CEMS readings, and/or changes in the location of the CEMS sample probe;

iv. the excess emissions report (EER)*, i.e., a summary of any exceedances during the calendar quarter, as specified above;

v. the total CO emissions for the calendar quarter (tons);

vi. the total operating time (hours) of the emissions unit;

vii. the total operating time of the continuous CO monitoring system while the emissions unit was in operation;

viii. results and dates of quarterly cylinder gas audits;

ix. unless previously submitted, results and dates of the relative accuracy test audit(s), including results in units of the applicable standard(s), (during appropriate quarter(s));

x. unless previously submitted, the results of any relative accuracy test audit showing the continuous CO monitor out-of-control and the compliant results following any corrective actions;

xi. the date, time, and duration of any/each malfunction** of the continuous CO monitoring system, emissions unit, and/or control equipment;

xii. the date, time, and duration of any downtime** of the continuous CO monitoring system and/or control equipment while the emissions unit was in operation; and

xiii. the reason (if known) and the corrective actions taken (if any) for each event in (b)(xi) and (xii).

Each report shall address the operations conducted and data obtained during the previous calendar quarter. Data substitution procedures from 40 CFR 75 are not to be used for showing compliance with the short term OAC 3745-31-05(A)(3) rule-based or NSPS-based limitation(s) in this permit.

* where no excess emissions have occurred or the continuous monitoring system(s) has/have not been inoperative, repaired, or adjusted during the calendar quarter, such information shall be documented in the EER quarterly report

** each downtime and malfunction event shall be reported regardless if there is an exceedance of any applicable limit

(7) The permittee shall collect, record and maintain measurements, data, records and reports required per 40 CFR Part 75; and shall submit certification, recertification, notifications, applications, monitoring plans, petitions for alternative monitoring systems, electronic quarterly reports and any other pertinent record and/or report to the Administrator (U.S. EPA), as required by this Part.

(8) The permittee shall submit annual reports that include any changes to any parameter or value used in the dispersion model used to demonstrate compliance with the “Toxic Air Contaminate Statute”, ORC 3704.03(F), through the predicted 1 hour maximum concentration. The report should include:

a. the original model input;

b. the updated model input;

c. the reason for the change(s) to the input parameter(s);

d. a summary of the results of the updated modeling, including the input changes; and

e. a statement that the model results indicate that the 1-hour maximum ground-level concentration is less than 80% of the MAGLC.

If no changes to the emissions, emissions unit(s), or the exhaust stack have been made during the reporting period, then the report shall include a statement to that effect.

(9) See 40 CFR Part 60, Subpart KKKK (40 CFR 60.4300 – 60.4420).

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

Visible particulate emissions from the stack serving this emissions unit shall not exceed 10% opacity as a 6-minute average.

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance based upon an emission test performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

b. Emission Limitation:

CO emissions from this emissions unit shall not exceed 2.0 ppmvd at 15% oxygen as an hourly average and 15.17 lbs/hr when firing natural gas and the duct burner is not in operation; 2.0 ppmvd at 15% oxygen as an hourly average and 18.57 lbs/hr when firing natural gas and the duct burner is in operation; and 2.0 ppmvd at 15% oxygen as an hourly average and 16.15 lbs/hr when firing ULSD fuel.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data. Ongoing compliance with the CO emission limitations shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

The permittee shall demonstrate compliance using Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA. See f)(2).

c. Emission Limitation:

CO emissions from this emissions unit shall not exceed 158.3 lbs/hr during startup and 160.1 lbs/hr during shutdown when firing natural gas; and 356.6 lbs/hr during startup and 132.3 lbs/hr during shutdown when firing ULSD fuel.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data. Ongoing compliance with the CO emission limitations shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

The permittee shall demonstrate compliance using Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA. See f)(2).

d. Emission Limitation:

CO emissions from this emissions unit shall not exceed 108.1 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance shall be based upon record keeping as specified in d)(10) and shall be demonstrated through the use of CEMs as specified in d)(14).

The monthly CO emissions shall be added to the total CO emissions from the previous eleven months to determine the rolling, 12-month summation of CO emissions.

e. Emission Limitation:

NO_x emissions from this emissions unit shall not exceed 2.0 ppmvd at 15% oxygen as an hourly average and 24.92 lbs/hr when firing natural gas and the duct burner is not in operation; 2.0 ppmvd at 15% oxygen as an hourly average and 30.51 lbs/hr when firing natural gas and the duct burner is in operation; and 5.0 ppmvd at 15% oxygen as an hourly average and 66.32 lbs/hr when firing ULSD fuel.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data. Ongoing compliance with the NO_x emission limitations shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

The permittee shall demonstrate compliance using Methods 1 thru 4 and 7E of 40 CFR Part 60, Appendix A, and the procedures specified in 40 CFR 60.4400. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA. See f)(2).

f. Emission Limitation:

NO_x emissions from this emissions unit shall not exceed 231.4 lbs/hr during startup and 26.5 lbs/hr during shutdown when firing natural gas; and 181.3 lbs/hr during startup and 85.4 lbs/hr during shutdown when firing ULSD fuel.

Applicable Compliance Method:

These emissions limitations are based on manufacturer's data. Ongoing compliance with the NO_x emission limitations shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

The permittee shall demonstrate compliance using Methods 1 thru 4 and 7E of 40 CFR Part 60, Appendix A, and the procedures specified in 40 CFR 60.4400. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA. See f)(2).

g. Emission Limitation:

NO_x emissions from this emissions unit shall not exceed 151.3 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance shall be based upon record keeping as specified in d)(10) and shall be demonstrated through the use of CEMs as specified in d)(12).

The monthly NO_x emissions shall be added to the total NO_x emissions from the previous eleven months to determine the rolling, 12-month summation of NO_x emissions.

h. Emission Limitation:

VOC emissions from this emissions unit shall not exceed 1.0 ppmvd at 15% oxygen as an hourly average and 4.35 lbs/hr when firing natural gas and the duct burner is not in operation; 2.0 ppmvd at 15% oxygen as an hourly average and 10.64 lbs/hr when firing natural gas and the duct burner is in operation; and 2.0 ppmvd at 15% oxygen as an hourly average and 9.25 lbs/hr when firing ULSD fuel.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data. The permittee shall demonstrate compliance with this emission limitation through emission testing performed in accordance with Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA. See f)(2).

i. Emission Limitation:

VOC emissions from this emissions unit shall not exceed 21.4 lbs/hr during startup and 55.2 lbs/hr during shutdown when firing natural gas; and 109.0 lbs/hr during startup and 41.3 lbs/hr during shutdown when firing ULSD fuel.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data. The permittee shall demonstrate compliance with this emission limitation through emission testing performed in accordance with Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

j. Emission Limitation:

VOC emissions from this emissions unit shall not exceed 50.6 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance shall be based upon record keeping as specified in d)(10) and shall be demonstrated through a summation of the VOC emissions from the burning of natural gas and ULSD fuel as follows:

i. The VOC emissions for each emissions unit from the burning of natural gas shall be determined by multiplying the operating hours while burning natural gas for the month, by the average emission rate (lbs VOC/hour) derived from the emission tests conducted in accordance with Section f)(2), and dividing by 2,000 lbs/ton.

ii. The VOC emissions for each emissions unit from the burning of ULSD fuel shall be determined by multiplying the operating hours while burning ULSD fuel for the month, by the average emission rate (lbs VOC/hour) derived from the emission tests conducted in accordance with f)(2), and dividing by 2,000 lbs/ton.

iii. The monthly VOC emissions shall be added to the total VOC emissions from the previous 11 months to determine the rolling, 12-month summation of VOC emissions, using the operating hour data from d)(10) and the average emission rates derived from the emission tests conducted in accordance with f)(2).

k. Emission Limitation:

SO_2 emissions from this emissions unit shall not exceed 1.4E-03 lb/MMBtu and 4.61 lbs/hr when firing natural gas and the duct burner is not in operation; 1.4E-03 lb/MMBtu and 5.64 lbs/hr when firing natural gas and the duct burner is in operation; and1.5E-03 lb/MMBtu and 5.19 lbs/hr when firing ULSD fuel.

Applicable Compliance Method:

For pipeline quality natural gas having a maximum sulfur content of 0.5 grain per 100 standard cubic feet according to the following calculation: multiply the maximum sulfur content of natural gas (0.5 grain S/100 scf) by the molecular weight of SO_2 (64.07 lb SO_2/lb-mole), divide by the molecular weight of sulfur (32.06 lb S/lb-mole), divide by (7,000 grains/lb), divide by the expected heating value (HHV) for pipeline natural gas (1028 Btu/scf), and multiply by (10^6 Btu/MMBtu).

For ULSD fuel having a maximum sulfur content of 15 ppm, fuel sampling analysis for fuel oil as determined in d)(1).

When firing natural gas, compliance with the lb/hr emission limitation shall be based upon multiplying 1.4E-03 lb/MMBtu by the maximum heat input capacity (with and without the use of the duct burner) of this emissions unit.

When firing ULSD fuel, compliance with the lb/hr emission limitation shall be based upon the fuel analysis and record keeping requirements specified in d)(1) and shall be determined by multiplying the SO_2 emissions in lb(s) SO_2/MMBtu by the maximum heat input capacity of this emissions unit. The permittee shall demonstrate compliance with the hourly emission limitation when burning ULSD fuel through emission tests performed in accordance with 40 CFR Part 60, Appendix A, Methods 1 through 4 and 6. Alternative U.S. EPA-approved test methods may be used with prior approval from Ohio EPA.

l. Emission Limitation:

SO_2 emissions from this emissions unit shall not exceed 23.5 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance shall be based upon record keeping as specified in d)(10) and shall be demonstrated through a summation of the SO_2 emissions from the burning of natural gas and ULSD fuel as follows:

i. The monthly SO_2 emissions for each emissions unit from the burning of natural gas shall be determined by multiplying 1.4E-03 lb SO2/MMBtu by the actual heat input for these emissions units (MMBtu/month) and then dividing by 2,000 lbs/ton.

ii. The monthly SO_2 emissions for each emissions unit from the burning of ULSD fuel shall be determined by multiplying by the average percent sulfur of the ULSD fuel used during the month (or 0.0015% sulfur) by the factor of 2 lbs of SO_2 per lb of sulfur, divided by the average heat content of the fuel burned during the period, by the actual heat input while burning ULSD fuel oil in these emissions units (MMBtu/hr), and then dividing by 2,000 lbs/ton.

iii. The monthly SO_2 emissions shall be added to the total SO_2 emissions from the previous eleven months to determine the rolling, 12-month summation of SO_2 emissions, using 1.4E-03 lb SO_2/MMBtu and fuel sampling analysis for ULSD fuel as determined in d)(1).

m. Emission Limitation:

PM_{10} and $PM_{2.5}$ emissions from this emissions unit shall not exceed 7.7E-03 lb/MMBtu as an hourly average and 16.16 lbs/hr when firing natural gas and the duct burner is not in operation; 6.9E-03 lb/MMBtu as an hourly average and 25.0 lbs/hr when firing natural gas and the duct burner is in operation; and 1.9E-02 lb/MMBtu as an hourly average and 55.4 lbs/hr when firing ULSD fuel.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data. The permittee shall demonstrate compliance with these emission limitations using Methods 201A and 202 of 40 CFR Part 51, Appendix M. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA. See f)(2).

n. Emission Limitation:

PM_{10} and $PM_{2.5}$ emissions from this emissions unit shall not exceed 141.7 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance shall be based upon record keeping as specified in d)(10) and shall be demonstrated through a summation of the PM_{10} and $PM_{2.5}$ emissions from the burning of natural gas and ULSD fuel as follows:

i. The PM_{10} and $PM_{2.5}$ emissions for each emissions unit from the burning of natural gas shall be determined by multiplying the total fuel use (MMBtu) while burning natural gas for the month, by the average emission rate (lbs PM_{10} and $PM_{2.5}$/MMBtu) derived from the emission tests conducted in accordance with f)(2), and dividing by 2,000 lbs/ton.

ii. The PM_{10} and $PM_{2.5}$ emissions for each emissions unit from the burning of ULSD fuel shall be determined by multiplying the total fuel use (MMBtu) while burning ULSD fuel for the month, by the average emission rate (lbs PM_{10} and $PM_{2.5}$/MMBtu) derived from the emission tests conducted in accordance with f)(2), and dividing by 2,000 lbs/ton.

iii. The monthly PM_{10} and $PM_{2.5}$ emissions shall be added to the total PM_{10} and $PM_{2.5}$ emissions from the previous 11 months to determine the rolling, 12-month summation of PM_{10} and $PM_{2.5}$ emissions, using the total fuel use (MMBtu) data from the Part 75 certified fuel flow meters and the average emission rates derived from the emission tests conducted in accordance with f)(2).

o. Emission Limitation:

H_2SO_4 emissions from this emissions unit shall not exceed 1.7E-03 lb/MMBtu as an hourly average and 5.65 lbs/hr when firing natural gas and the duct burner is not in operation; 1.7E-03 lb/MMBtu as an hourly average and 6.96 lbs/hr when firing natural gas and the duct burner is in operation; and 1.9E-03 lb/MMBtu as an hourly average and 6.35 lbs/hr when firing ULSD fuel.

Applicable Compliance Method:

These emission limitations are based on manufacturer's data. The permittee shall demonstrate compliance using Methods 1 thru 4 and 8 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA. See f)(2).

p. Emission Limitation:

H_2SO_4 emissions from this emissions unit shall not exceed 29.0 tons per rolling, 12-month period.

Applicable Compliance Method:

Compliance shall be based upon record keeping as specified in d)(10) and shall be determined through a summation of the H_2SO_4 emissions from the burning of natural gas and ULSD fuel as follows:

i. The H_2SO_4 emissions for each emissions unit from the burning of natural gas shall be determined by multiplying the fuel use in MMBtu while burning natural gas for the month, by the average emission rate (lbs H_2SO_4/MMBtu) derived from the emission tests conducted in accordance with f)(2), and dividing by 2,000 lbs/ton.

ii. The H_2SO_4 emissions for each emissions unit from the burning of ULSD fuel shall be determined by multiplying the fuel use in MMBtu while burning ULSD fuel for the month, by the average emission rate (lbs H_2SO_4/MMBtu) derived from the emission tests conducted in accordance with f)(2), and dividing by 2,000 lbs/ton.

iii. The monthly H_2SO_4 emissions shall be added to the total H_2SO_4 emissions from the previous 11 months to determine the rolling, 12-month summation of H_2SO_4 emissions, using the fuel use data from the Part 75 certified fuel flow meters and the average emission rates derived from the emission tests conducted in accordance with f)(2).

q. Emission Limitation:

CO_2e emissions shall not exceed 481,301 lbs/hr when firing natural gas (maximum under any condition with duct firing).

CO_2e emissions shall not exceed 546,182 lbs/hr when firing ULSD fuel.

CO_2e emissions shall not exceed 2,045,634.5 tons per rolling, 12-month period during all operating modes, including startup and shutdown periods.

Applicable Compliance Method:

Compliance with the maximum hourly emission limitation is based on the following calculation:

Natural Gas (Manufacturer's data GE Case #1):

CO_2: (4,045.31 MMBtu/hr)(118.857 lb/MMBtu[a]) = 480,813 lbs/hr

CH_4: (4,045.31 MMBtu/hr)(2.2E-03 lb/MMBtu[b]) = 8.9 lbs/hr

N_2O: (4,045.31 MMBtu/hr)(2.2E-04 lb/MMBtu[c]) = 0.89 lb/hr

where:

"a" is the emission factor from USEPA 40 CFR Part 75;

"b" is the emission factor from USEPA 40 CFR Part 98; and

"c" is the emission factor from USEPA 40 CFR Part 98.

The hourly emission limitation is based on the sum of the following manufacturer's data GE Case #1 (480,813 lbs/hr CO_2, 8.90 lbs/hr CH_4, and 0.89 lbs/hr N_2O) multiplied by the associated global warming potential for each pollutant (CO_2=1, CH_4=25, N_2O=298 from Table A-1 of 40 CFR 98).

$$\left[\left(480{,}813\,\frac{lbs}{hr}\right)(1)+\left(8.90\,\frac{lbs}{hr}\right)(25)+\left(0.89\,\frac{lbs}{hr}\right)(298)\right] = 481{,}301 \text{ lbs/hr}$$

ULSD Fuel (Manufacturer's data GE Case #20):

CO_2: (3,354 MMBtu/hr)(162.286 lb/MMBtu[a]) = 544,307.24 lbs/hr

CH_4: (3,354 MMBtu/hr)(6.61E-03 lb/MMBtu[b]) = 22.17 lbs/hr

N_2O: (3,354 MMBtu/hr)(1.32E-03 lb/MMBtu[c]) = 4.43 lbs/hr

where:

"a" is the emission factor from USEPA 40 CFR Part 75;

"b" is the emission factor from USEPA 40 CFR Part 98; and "c" is the emission factor from USEPA 40 CFR Part 98.

The hourly emission limitation is based on the sum of the following manufacturer's data GE Case #20 (544,307.24 lbs/hr CO_2, 22.17 lbs/hr CH_4, and 4.43 lbs/hr N_2O) multiplied by the associated global warming potential for each pollutant (CO_2=1, CH_4=25, N_2O=298 from Table A-1 of 40 CFR 98).

$$\left[\left(544{,}307.24\frac{lbs}{hr}\right)(1)+\left(22.17\frac{lbs}{hr}\right)(25)+\left(4.43\frac{lbs}{hr}\right)(298)\right] = 546{,}182 \text{ lbs/hr}$$

Compliance with the annual emission limitation is based on the following calculation:

Natural Gas (Manufacturer's data GE Case #7):

CO_2: [(3,843.42 MMBtu/hr)(118.857 lb/MMBtu[a])(7,320 hours/yr)]/(2,000 lbs/ton) = 1,671,952 tpy

CH_4: [(3,843.42 MMBtu/hr)(2.2E-03 lb/MMBtu[b])(7,320 hours/yr)]/(2,000 lbs/ton) = 31.0 tpy

N_2O: [(3,843.42 MMBtu/hr)(2.2E-04 lb/MMBtu[c])(7,320 hours/yr)]/(2,000 lbs/ton) = 3.10 tpy

where:

"a" is the emission factor from USEPA 40 CFR Part 75;

"b" is the emission factor from USEPA 40 CFR Part 98; and

"c" is the emission factor from USEPA 40 CFR Part 98.

The annual emission calculation for natural gas is based on the sum of the following manufacturer's data GE Case #7 (1,671,952 tpy CO_2, 31.0 tpy CH_4, and 3.10 tpy N_2O) multiplied by the associated global warming potential for each pollutant (CO_2=1, CH_4=25, N_2O=298 from Table A-1 of 40 CFR 98).

$$\left[\left(1{,}671{,}952\frac{tons}{yr}\right)(1)+\left(31.0\frac{tons}{yr}\right)(25)+\left(3.10\frac{tons}{yr}\right)(298)\right] = 1{,}673{,}651 \text{ tons/yr}$$

ULSD Fuel (Manufacturer's data GE Case #24):

CO_2: [(3,172.6 MMBtu/hr)(162.286 lb/MMBtu[a])(1,440 hours/yr)]/(2,000 lbs/ton) = 370,705 tpy

CH_4: [(3,172.6 MMBtu/hr)(6.61E-03 lb/MMBtu[b])(1,440 hours/yr)]/(2,000 lbs/ton) = 15.11 tpy

N_2O: [(3,172.6 MMBtu/hr)(1.32E-03 lb/MMBtu[c])(1,440 hours/yr)]/(2,000 lbs/ton) = 3.02 tpy

where:

"a" is the emission factor from USEPA 40 CFR Part 75;

"b" is the emission factor from USEPA 40 CFR Part 98; and

"c" is the emission factor from USEPA 40 CFR Part 98.

The annual emission limitation is based on the sum of the following manufacturer's data GE Case #24 (370,705 tpy CO_2, 15.11 tpy CH_4, and 3.02 tpy N_2O) multiplied by the associated global warming potential for each pollutant (CO_2=1, CH_4=25, N_2O=298 from Table A-1 of 40 CFR 98).

$$\left[\left(370{,}705\,\frac{tons}{yr}\right)(1)+\left(15.11\,\frac{tons}{yr}\right)(25)+\left(3.02\,\frac{tons}{yr}\right)(298)\right] = 371{,}983 \text{ tons/yr}$$

Total CO_{2e}: (Natural Gas 1,673,651 tpy) + (ULSD 371,983 tpy) = 2,045,634 tpy CO_{2e} per CTG.

r. Emission Limitation:

CO_2 emissions shall not exceed 450 kg per megawatt-hour (MWh) of gross energy output (1,000 lb CO_2/MWh) or

CO_2 emissions shall not exceed 470 kg per MWh of net energy output (1,030 lb CO_2/MWh).

Applicable Compliance Method:

Compliance with the above emissions limitations shall be determined in accordance with the following:

60.5540	Demonstrating Compliance with the CO_2 Emissions Standard

(2) The permittee shall conduct, or have conducted, emission testing for this emissions unit in accordance with the following requirements:

a. The emission testing shall be conducted within 60 days after achieving the maximum production rate at which the emissions unit will be operated, but not later than 180 days after initial startup of the emissions unit.

b. The emission testing shall be conducted to demonstrate compliance with the allowable mass emission rate(s) for CO, NO_x, SO_2, PM_{10}, $PM_{2.5}$, VOC and H_2SO_4, in the appropriate averaging period(s).

The emission testing shall include startup and shutdown for CO, NOx, and VOC emissions while burning both natural gas and ULSD.

The emission testing shall also be conducted to determine a site-specific emission factor for CO_2, in lb/MMBtu.

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

for CO, Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A;

for NO_x, Methods 1 thru 4 and 7E of 40 CFR Part 60, Appendix A, and the procedures specified in 40 CFR 60.4400;

for PM_{10} and $PM_{2.5}$, Methods 201A and 202 of 40 CFR Part 51, Appendix M;

for SO_2, 40 CFR 60.4415;

for VOC, Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents;

for H_2SO_4, Methods 1 thru 4 and 8 of 40 CFR Part 60, Appendix A; and

for CO_2, Methods 1, 2, 3A, and 4 of 40 CFR Part 60, Appendix A, mass balance calculations using ASTM D1945-03 (Standard Test Method for Analysis of Natural Gas by Gas Chromatography) and/or ASTM D1826-94 (Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter).

Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

d. The test(s) shall be conducted under those representative conditions that challenge to the fullest extent possible a facility's ability to meet the applicable emissions limits and/or control requirements, unless otherwise specified or approved by the Ohio EPA Northeast District Office. Although this generally consists of operating the emissions unit at its maximum material input/production rates and results in the highest emission rate of the tested pollutant, there may be circumstances where a lower emissions loading is deemed the most challenging control scenario. Failure to test under these conditions is justification for not accepting the test results as a demonstration of compliance.

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

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

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

(3) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous NO_x emission monitoring system, in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specification 2 relative accuracy requirements; ORC section 3704.03(I); and 40 CFR Part 75.

The permittee shall certify that the fuel flow monitor/meter meets 40 CFR Part 75 certification requirements prior to the performance specification test and shall demonstrate how the pound per hour emissions of NO_x will be calculated stoichiometrically from the fuel flow rate.

Personnel from the Ohio EPA Central Office and the Ohio EPA Northeast District Office shall be notified 45 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the Ohio EPA Northeast District Office and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification, or recommendation for certification by Ohio EPA to U.S. EPA, of the continuous NO_x monitoring system shall be granted upon determination by the Ohio EPA, Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specification 2 relative accuracy requirements; ORC section 3704.03(I); and 40 CFR Part 75.

Ongoing compliance with the NO_x emissions limitations contained in this permit, 40 CFR Parts 60 and 75, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the testing and recertification requirements of 40 CFR Part 60 and 40 CFR Part 75.

(4) Within 60 days of achieving the maximum production rate at which the emissions unit(s) will be operated, but not later than 180 days after initial startup, the permittee shall conduct certification tests of the continuous CO monitoring system in units of the applicable standard(s), to demonstrate compliance with 40 CFR Part 60, Appendix B, Performance Specification 4 or 4a (as appropriate) relative accuracy requirements; and ORC section 3704.03(I).

The permittee shall certify that the fuel flow monitor/meter is calibrated prior to the performance specification test and shall demonstrate how the pound per hour emissions of CO will be calculated stoichiometrically from the fuel flow rate.

Personnel from the Ohio EPA Central Office and the Ohio EPA Northeast District Office shall be notified 30 days prior to initiation of the applicable tests and shall be permitted to examine equipment and witness the certification tests. Two copies of the test results shall be submitted to Ohio EPA, one copy to the Ohio EPA Northeast District Office and one copy to Ohio EPA Central Office, and pursuant to OAC rule 3745-15-04, within 30 days after the test is completed.

Certification of the continuous CO monitoring system shall be granted upon determination by the Ohio EPA Central Office that the system meets the requirements of 40 CFR Part 60, Appendix B, Performance Specification 4 or 4a (as appropriate) relative accuracy requirements; and ORC section 3704.03(I).

Ongoing compliance with the CO emission limitations contained in this permit, 40 CFR Part 60, and any other applicable standard(s) shall be demonstrated through the data collected as required in the Monitoring and Record keeping Section of this permit and through demonstration of compliance with the quality assurance/quality control plan, which shall meet the requirements of 40 CFR Part 60.

g) Miscellaneous Requirements

(1) None.

3. P003, Emergency Generator

Operations, Property and/or Equipment Description:

2,000 kW electric, 2,198 kW mechanical (2,947 hp) emergency diesel generator

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

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

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	See b)(2)a. and b)(2)b.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the $PM_{2.5}$, PM_{10}, NO_x, CO, SO_2, or VOC emissions from this air contaminant source since the potential to emit is less than 10 tons per year. See b)(2)c.
c.	OAC rules 3745-31-10 through 20 (Prevention of Significant Deterioration of Air Quality)	Carbon monoxide (CO) emissions shall not exceed 3.5 g/kW-hr, 16.96 pounds per hour (lbs/hr), and 4.24 tons per rolling, 12-month period. Nitrogen oxides (NO_x) emissions shall not exceed 5.61 g/kW-hr, 27.18 lbs/hr, and 6.80 tons per rolling, 12-month period. Particulate matter emissions less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) shall not exceed 0.20 g/kW-hr, 0.97 lb/hr, and 0.24 ton per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 0.79 g/kW-hr,

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		3.84 lbs/hr, and 0.96 ton per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 0.03 pound per hour (lb/hr) and 0.01 ton per rolling, 12-month period. Sulfuric acid mist (H_2SO_4) emissions shall not exceed 1.32E-04 g/kW-hr, 6.4 E-04 lb/hr and 1.6E-04 ton per rolling, 12-month period. Carbon dioxide equivalent (CO_2e) emissions shall not exceed 858.0 tons per rolling, 12-month period. See b)(2)d.
d.	OAC rule 3745-31-05(F)	See b)(2)e.
e.	OAC rule 3745-17-07(A)	Visible particulate emissions from the stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by the rule.
f.	OAC rule 3745-17-11(B)(5)(a)	See b)(2)f.
g.	OAC rule 3745-18-06(G)	Less stringent than 40 CFR Part 60, Subpart IIII.
h.	OAC rule 3745-110-03(K)(16) and (K)(19)	Exemptions. See b)(2)g.
i.	40 CFR Part 60, Subpart A (40 CFR 60.1 - 60.19)	Table 8 to Subpart IIII of 40 CFR Part 60 – Applicability of General Provisions to Subpart IIII shows which parts of the General Provisions in 40 CFR 60.1 - 60.19 apply.
j.	40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219) [In accordance with 40 CFR 60.4200(a)(2), this emissions unit is a compression ignition emergency stationary internal combustion engine (CI ICE) for which construction commenced after July 11, 2005 subject to the emissions limitation/control measures specified in this section.]	Non-methane hydrocarbon (NMHC) + NO_x emissions shall not exceed 6.4 g/kW-hr. CO emissions shall not exceed 3.5 g/kW-hr. PM emissions shall not exceed 0.20 g/kW-hr. Exhaust opacity shall not exceed: 20 percent during acceleration mode; 15 percent during lugging mode; and 50 percent during the peaks in either the

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		acceleration or lugging modes. See b)(2)h. [60.4205(b) and 60.4207(b)]
k.	40 CFR Part 63, Subpart ZZZZ (40 CFR 63.6580-63.6675) [In accordance with 40 CFR 63.6590(c)(1), this emissions unit is a new stationary internal combustion engine (RICE) located at an area source of HAP emissions subject to the emissions limitation/control measures specified in this section.]	See b)(2)i. [63.6590(c), (c)(1)]
l.	40 CFR Part 63, Subpart A (40 CFR 63.1 – 40 CFR 63.16)	See b)(2)j.

(2) Additional Terms and Conditions

a. Compliance with the requirements of this rule for CO, NO_x, $PM_{10}/PM_{2.5}$, SO_2 and VOC emissions includes compliance with the requirements of OAC rules 3745-31-10 through 20.

b. The BAT emission limits apply until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

c. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) as part of the Ohio SIP.

d. All particulate emissions are assumed to be less than 2.5 microns in diameter. The $PM_{10}/PM_{2.5}$ emission limitations include both filterable and condensable particulate emissions.

e. The maximum annual operating hours for this emissions unit shall not exceed 500 hours, based upon a rolling, 12-month summation of the operating hours.

f. The emission limitation required by this applicable rule is less stringent than the emission limitation established by OAC rules 3745-31-10 through 20.

g. The requirements of this rule do not apply, since:

i. NO_x emissions are restricted to less than 25 tons per year; and

ii. the emissions unit is subject to a BACT limitation for NO_x.

h. The permittee shall only combust ULSD fuel in this emissions unit meeting the following standards:

i. 15 ppm maximum sulfur content; and

ii. a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

i. This emissions unit must meet the requirements of 40 CFR Part 60, Subpart IIII. No further requirements apply under this subpart.

j. Table 8 to Subpart ZZZZ of 40 CFR Part 63 – Applicability of General Provisions to Subpart ZZZZ shows which parts of the General Provisions in 40 CFR 63.1 - 63.16 apply.

c) Operational Restrictions

(1) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 - 60.4219).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall maintain monthly records of the following information:

a. the operating hours for each month; and

b. beginning after the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the rolling, 12-month summation of the operating hours.

Also, during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall record the cumulative operating hours for each calendar month.

(2) For each shipment of ULSD fuel received for burning in this emissions unit, the permittee shall maintain records of the oil supplier's (or permittee’s) analyses for sulfur content in parts per million (40 CFR 80.510). The permittee shall perform or require the supplier to perform the analyses for sulfur content in accordance with 40 CFR 80.585.

(3) The permittee shall also maintain documentation of supplier verification that the ULSD fuel as purchased has a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

(4) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 - 60.4219).

e) Reporting Requirements

(1) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each shipment of ULSD fuel received for burning in this emissions unit that did not comply with the standards specified in b)(2)h; and

b. all exceedances of the rolling, 12-month limitation on the hours of operation for this emissions unit.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(2) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 - 60.4219).

(3) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 3.5 g/kW-hr, 16.96 lbs/hr, and 4.24 tons per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr limitation is based on the Tier 2 emission standards under 40 CFR 89.112(a), Subpart B, Table 1. The hourly emission limitation was developed by multiplying the maximum operating load (2,198 kW) by the CO emission factor supplied by the manufacturer (3.5 g/kW-hr) and dividing by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (16.96 lbs/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

b. Emission Limitation:

NO_x emissions shall not exceed 5.61 g/kW-hr, 27.18 lbs/hr, and 6.80 tons per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr limitation is based on the combined NO_x + NMHC emission limitation specified by the Tier 2 standard in 40 CFR 89.112(a) Table 1 (6.4

g/kW-hr) multiplied by the Tier 1 emission limitation for NO_x in Table 1 (9.2 g/kW-hr) divided by the sum of the Tier 1 emission limitations for NO_x and HC in Table 1 (9.2 g/kW-hr + 1.3 g/kW-hr). The hourly emission limitation was developed by multiplying the maximum operating load (2,198 kW mechanical) by the NO_x g/kW-hr emission limitation (5.61 g/kW-hr) divided by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 1 thru 4 and 7E of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (27.18 lbs/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

c. Emission Limitation:

$PM_{10}/PM_{2.5}$ emissions shall not exceed 0.20 g/kW-hr, 0.97 lb/hr, and 0.24 ton per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr limitation is based on manufacturer's emissions data. The hourly emission limitation was developed by multiplying the maximum operating load (2,198 kW mechanical) by the $PM_{10}/PM_{2.5}$ emission factor supplied by the manufacturer (0.20 g/kW-hr) divided by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 201 or 201A and 202 of 40 CFR Part 51, Appendix M. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (0.97 lb/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

d. Emission Limitation:

SO_2 emissions shall not exceed 0.03 lb/hr and 0.01 ton per rolling, 12-month period.

Applicable Compliance Method:

The hourly emission limitation is based on dividing the AP-42 emission factor for SO_2 from AP-42 Table 3.4-1 dated 10/96 when burning diesel fuel with a maximum sulfur content of 15 ppmw (0.0015 lb/MMBtu) multiplied by the maximum power rating (19.32 MMBtu/hr).

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 1 thru 4 and 6C of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (0.03 lb/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

e. Emission Limitation:

VOC emissions shall not exceed 0.79 g/kW-hr, 3.84 lbs/hr, and 0.96 ton per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr limitation is based on the combined NO_x + NMHC emission limitation specified by the Tier 2 standard in 40 CFR 89.112(a) Table 1 (6.4 g/kW-hr) multiplied by the Tier 1 emission limitation for NMHC in Table 1 (1.3 g/kW-hr) divided by the sum of the Tier 1 emission limitations for NO_x and HC in Table 1 (9.2 g/kW-hr + 1.3 g/kW-hr). The hourly emission limitation was developed by multiplying the maximum operating load (2,198 kW mechanical) by the VOC emission factor supplied by the manufacturer (0.79 g/kW-hr) divided by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (3.84 lbs/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

f. Emission Limitation:

H_2SO_4 emissions shall not exceed 1.32E-04 g/kW-hr, 6.4E-04 lb/hr and 1.6E-04 ton per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr emission is based on the sulfuric acid mist emission factor from page 276 of Toxic Air Pollution Emission Factors, EPA 450/2-90-011 (8.9 ng/J x %sulfur in fuel = 8.9(0.0015) = 0.01335 ng/J). The H_2SO_4 emission factor (0.01335 ng/J) was converted to g/kW-hr by multiplying by (1055.1 J/Btu), multiplying by (7000 Btu/hp-hr), multiplying by (g/10^9 ng), and multiplying by (1.341 hp/kW) = 1.32E-04 g/kW-hr.

The pound per hour emissions limitation was developed by multiplying the g/kW-hr allowable H_2SO_4 emission limitation (1.32E-04 g/kW-hr) by the maximum operating load (2,198 kW mechanical) and dividing by 454 grams per pound to determine the hourly emissions (6.4E-04 lb/hr).

If required, the permittee shall demonstrate compliance with the g/kW-hr and lb/hr emission limitation using Methods 1 thru 4 and 8 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly allowable H_2SO_4 emission limitation (6.4E-04 lb/hr) by the maximum annual hours of operation (500 hours), and then dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

g. Emission Limitation:

CO_2e emissions shall not exceed 858.0 tons per rolling, 12-month period.

Applicable Compliance Method:

This emissions limitation was established to reflect the potential to emit for this emissions unit by calculating the sum of the maximum capacity (2,947 hp) by the emission factors for CO_2, N_2O, and CH_4, multiplied by the global warming potentials for CO_2, N_2O, and CH_4 (1, 298, and 25, respectively from Table A-1 to Subpart A of 40 CFR 98). Multiply the sum by the maximum annual hours of operation (500 hrs/yr) and divide by 2,000 pounds per ton. The CO_2 emission factor was obtained from AP-42 Table 3.4-1 dated 10/96 (1.16 lb/hp-hr). The N_2O emission factor was obtained from 40 Table C-2 to Subpart C of 40 CFR 98 (0.6 g/MMBtu). The CH_4 emission factor was obtained from AP-42 Table 3.4-1 dated 10/96 (7.05E-04 lb TOC/hp-hr x 0.09 lb CH_4/lb TOC = 6.34E-05 lb CH_4/hp-hr).

$$(2{,}947\ hp)x\left[\left(1.16\frac{lb}{hp-hr}(1)\right)+\left(\left(0.6\frac{g}{mmBtu}\right)\left(7000\frac{Btu}{hp-hr}\right)\left(\frac{mmBtu}{1E06Btu}\right)\left(\frac{lb}{454g}\right)(298)\right)+\left(6.34E-05\frac{lb}{(hp-hr)}\right)(25)\right]x\left(500\frac{hrs}{hr}\right)x\left(\frac{ton}{2{,}000lb}\right)=858.0\ tons/yr$$

Since the CO_2e emissions are estimated to consist of more than 99% CO_2, compliance with this emission limitation will be assumed provided that the lb/hp-hr CO_2 emission rate does not exceed 1.16 lb/hp-hr. If required, the permittee shall conduct emissions testing using Methods 1, 2, 3A and 4 of 40 CFR Part 60, Appendix A to determine the lb/hp-hr CO_2 emission rate. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

h. Emission Limitation:

The permittee shall only combust ULSD fuel in this emissions unit meeting the following standard: 15 ppm maximum sulfur content.

Applicable Compliance Method:

Compliance shall be demonstrated based upon the record keeping requirements specified in d)(2).

i. Emission Limitation:

The permittee shall only combust ULSD fuel in this emissions unit meeting the following standard: a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

Applicable Compliance Method:

Compliance shall be demonstrated based upon the record keeping requirements specified in d)(2) and d)(3).

j. Emission Limitation:

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

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance based upon an emission test performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9.

k. Emission Limitation:

NMHC + NO_x emissions shall not exceed 6.4 g/kW-hr.

CO emissions shall not exceed 3.5 g/kW-hr.

PM emissions shall not exceed 0.20 g/kW-hr.

Exhaust opacity shall not exceed:

20 percent during acceleration mode;

15 percent during lugging mode; and

50 percent during the peaks in either the acceleration or lugging modes.

Applicable Compliance Method:

According to 40 CFR 60.4211(c), the permittee shall demonstrate compliance with these emission limitations by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b) for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). The permittee shall maintain documentation of certification to the emission standards in 40 CFR 60.4205.

g) Miscellaneous Requirements

(1) None.

4. P004, Emergency Fire Pump

Operations, Property and/or Equipment Description:

311 hp (232.1 kW mechanical) emergency fire pump

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

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

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	See b)(2)a. and b)(2)b.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the $PM_{2.5}$, PM_{10}, NO_x, CO, SO_2, or VOC emissions from this air contaminant source since the potential to emit is less than 10 tons per year. See b)(2)c.
c.	OAC rules 3745-31-10 through 20 (Prevention of Significant Deterioration of Air Quality)	Carbon monoxide (CO) emissions shall not exceed 3.5 g/kW-hr, 1.79 pounds per hour (lbs/hr), and 0.45 ton per rolling, 12-month period. Nitrogen oxides (NO_x) emissions shall not exceed 3.5 g/kW-hr, 1.79 lbs/hr, and 0.45 ton per rolling, 12-month period. Particulate matter emissions less than 10 microns in diameter (PM_{10}) and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) shall not exceed 0.20 g/kW-hr, 0.10 lb/hr, and 0.03 ton per rolling, 12-month period. Volatile organic compound (VOC) emissions shall not exceed 0.5 g/kW-hr,

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		0.25 lb/hr, and 0.06 ton per rolling, 12-month period. Sulfur dioxide (SO_2) emissions shall not exceed 0.004 lb/hr and 1.0E-03 ton per rolling, 12-month period. Sulfuric acid mist (H_2SO_4) emissions shall not exceed 1.32E-04 g/kW-hr, 6.7E-05 lb/hr and 1.7E-05 ton per rolling, 12-month period. Carbon dioxide equivalent (CO_2e) emissions shall not exceed 90.0 tons per rolling, 12-month period. See b)(2)d.
d.	OAC rule 3745-31-05(F)	See b)(2)e.
e.	OAC rule 3745-17-07(A)	Visible particulate emissions from the stack serving this emissions unit shall not exceed 20% opacity as a 6-minute average, except as provided by the rule.
f.	OAC rule 3745-17-11(B)(5)(a)	See b)(2)f.
g.	OAC rule 3745-110-03(K)(16) and (K)(19)	Exemption. See b)(2)g.
h.	40 CFR Part 60, Subpart A (40 CFR 60.1 - 60.19)	Table 8 to Subpart IIII of 40 CFR Part 60 – Applicability of General Provisions to Subpart IIII shows which parts of the General Provisions in 40 CFR 60.1 - 60.19 apply.
i.	40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219) [In accordance with 40 CFR 60.4200(a)(2), this emissions unit is a compression ignition stationary internal combustion fire pump engine for which construction commenced after July 11, 2005 subject to the emissions limitation/control measures specified in this section.]	Non-methane hydrocarbon (NMHC) + NO_x emissions shall not exceed 4.0 g/kW-hr. CO emissions shall not exceed 3.5 g/kW-hr. PM emissions shall not exceed 0.20 g/kW-hr. See b)(2)h. [60.4205(c) and 60.4207(b)]
j.	40 CFR Part 63, Subpart ZZZZ (40 CFR 63.6580 - 63.6675)	See b)(2)i. [63.6590(c), (c)(1)]

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	[In accordance with 40 CFR 63.6590(c)(1), this emissions unit is a new stationary reciprocating internal combustion engine (RICE) located at an area source of HAP emissions subject to the emissions limitation/control measures specified in this section.]	
k.	40 CFR Part 63, Subpart A (40 CFR 63.1 - 63.16)	Table 8 to Subpart ZZZZ of 40 CFR Part 63 – Applicability of General Provisions to Subpart ZZZZ shows which parts of the General Provisions in 40 CFR 63.1 - 63.16 apply.

(2) Additional Terms and Conditions

a. Compliance with the requirements of this rule for CO, NO_x, $PM_{10}/PM_{2.5}$, SO_2 and VOC emissions includes compliance with the requirements of OAC rules 3745-31-10 through 20.

b. The BAT emission limits apply until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

c. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) as part of the Ohio SIP.

d. All particulate emissions are assumed to be less than 2.5 microns in diameter. The $PM_{10}/PM_{2.5}$ emission limitations include both filterable and condensable particulate emissions.

e. The maximum annual operating hours for this emissions unit shall not exceed 500 hours, based upon a rolling, 12-month summation of the operating hours.

f. The emission limitation required by this applicable rule is less stringent than the emission limitation established by OAC rules 3745-31-10 through 20.

g. The requirements of this rule do not apply since:

i. NO_x emissions are restricted to less than 25 tons per year; and

ii. the emissions unit is subject to a BACT limitation for NO_x.

h. The permittee shall only combust ULSD fuel in this emissions unit meeting the following standards:

i. 15 ppm maximum sulfur content; and

ii. a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

i. This emissions unit must meet the requirements of 40 CFR Part 60, Subpart IIII. No further requirements apply under this subpart.

c) Operational Restrictions

(1) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall maintain monthly records of the following information:

a. the operating hours for each month; and

b. beginning after the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the rolling, 12-month summation of the operating hours.

Also, during the first 12 calendar months of operation or the first 12 calendar months following the issuance of this permit, the permittee shall record the cumulative operating hours for each calendar month.

(2) For each shipment of ULSD fuel received for burning in this emissions unit, the permittee shall maintain records of the oil supplier's (or permittee’s) analyses for sulfur content in parts per million (40 CFR 80.510). The permittee shall perform or require the supplier to perform the analyses for sulfur content in accordance with 40 CFR 80.585.

(3) The permittee shall also maintain documentation of supplier verification that the ULSD fuel as purchased has a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

(4) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

e) Reporting Requirements

(1) The permittee shall submit quarterly deviation (excursion) reports that identify the following:

a. each shipment of ULSD fuel received for burning in this emissions unit that did not comply with the standards specified in b)(2)h; and

b. all exceedances of the rolling, 12-month limitation on the hours of operation for this emissions unit.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(2) See 40 CFR Part 60, Subpart IIII (40 CFR 60.4200 – 60.4219).

(3) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

CO emissions shall not exceed 3.5 g/kW-hr, 1.79 lbs/hr, and 0.45 ton per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr limitation is based on the standard specified in Table 4 to 40 CFR Part 60, Subpart IIII. The hourly emission limitation was developed by multiplying the maximum operating load (232.1 kW mechanical) by the g/kW-hr CO emission limitation (3.5 g/kW-hr), and then dividing by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 1 thru 4 and 10 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (1.79 lbs/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

b. Emission Limitation:

NO_x emissions shall not exceed 3.5 g/kW-hr, 1.79 lbs/hr, and 0.45 ton per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr limitation is based on the combined NO_x + NMHC emission limitation specified by the Table 4 to 40 CFR Part 60, Subpart IIII (4.0 g/kW-hr) multiplied by the Tier 1 emission limitation for NO_x in Table 1 to 40 CFR 89.112(a) (9.2 g/kW-hr) divided by the sum of the Tier 1 emission limitations for NO_x and HC in Table 1 to 40 CFR 89.112(a) (9.2 g/kW-hr + 1.3 g/kW-hr). The hourly emission limitation was developed by multiplying the maximum operating load (232.1 kW mechanical) by the g/kW-hr NO_x emission limitation (3.5 g/kW-hr), and then dividing by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 1 thru 4 and 7E of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (1.79 lbs/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

c. Emission Limitation:

PM_{10}/$PM_{2.5}$ emissions shall not exceed 0.20 g/kW-hr, 0.10 lb/hr, and 0.03 ton per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr limitation is based on manufacturer's emissions data. The hourly emission limitation was developed by multiplying the maximum operating load (232.1 kW mechanical) by the PM_{10}/$PM_{2.5}$ emission factor supplied by the manufacturer (0.20 g/kW-hr), and then dividing by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 201 or 201A and 202 of 40 CFR Part 51, Appendix M. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (0.10 lb/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation is shown.

d. Emission Limitation:

SO_2 emissions shall not exceed 0.004 lb/hr and 1.0E-03 ton per rolling, 12-month period.

Applicable Compliance Method:

The hourly emission limitation is based on multiplying the AP-42 emission factor for SO_2 from AP-42 Table 3.4-1 dated 10/96 when burning diesel fuel with a maximum sulfur content of 15 ppmw (0.0015 lb/MMBtu) by the maximum heat input capacity of 2.64 MMBtu/hr.

If required, the permittee shall demonstrate compliance with the hourly emission limitation using Methods 1 thru 4 and 6C of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (0.004 lb/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation is shown.

e. Emission Limitation:

VOC emissions shall not exceed 0.5 g/kW-hr, 0.25 lb/hr, and 0.06 ton/yr as a rolling, 12-month summation of the monthly emissions.

Applicable Compliance Method:

The g/kW-hr limitation is based on the combined NO_x + NMHC emission limitation specified by the Table 4 to 40 CFR Part 60, Subpart IIII (4.0 g/kW-hr) multiplied by the Tier 1 emission limitation for NMHC in Table 1 to 40 CFR 89112(a) (1.3 g/kW-hr) divided by the sum of the Tier 1 emission limitations for NO_x and HC in Table 1 to 40 CFR 89.112(a) (9.2 g/kW-hr + 1.3 g/kW-hr). The hourly emission limitation was developed by multiplying the maximum operating load (232.1 kW mechanical) by the g/kW-hr VOC emission limitation (0.5 g/kW-hr) divided by (454 g/lb) to determine the hourly emissions.

If required, the permittee shall demonstrate compliance with the g/kW-hr limitation and hourly emission limitation using Methods 1 through 4 and 18, 25 or 25A, as appropriate, of 40 CFR Part 60, Appendix A. Use of Method 18, 25 or 25A is to be selected based on the results of pre-survey stack sampling and U.S. EPA guidance documents. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The annual emission limitation was developed by multiplying the hourly emission limitation (0.25 lb/hr) by the maximum annual operating hours (500 hrs/yr) and dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation is shown.

f. Emission Limitation:

H_2SO_4 emissions shall not exceed 1.32E-04 g/kW-hr, 6.7E-05 lb/hr and 1.7E-05 ton per rolling, 12-month period.

Applicable Compliance Method:

The g/kW-hr emission is based on the sulfuric acid mist emission factor from page 276 of Toxic Air Pollution Emission Factors, EPA 450/2-90-011 (8.9 ng/J x %sulfur in fuel = 8.9(0.0015) = 0.01335 ng/J). The H_2SO_4 emission factor (0.01335 ng/J) was converted to g/kW-hr by multiplying by (1055.1 J/Btu), multiplying by (7000 Btu/hp-hr), multiplying by ($g/10^9$ ng), and multiplying by (1.341 hp/kW) = 1.32E-04 g/kW-hr.

The pound per hour emission limitation was developed by multiplying the g/kW-hr allowable H_2SO_4 emission limitation (1.32E-04 g/kW-hr) by the maximum operating load (232.1 kW mechanical), and then dividing by 454 grams per pound to determine the hourly emissions (6.7E-05 lb/hr).

If required, the permittee shall demonstrate compliance with the g/kW-hr and lb/hr emission limitation using Methods 1 thru 4 and 8 of 40 CFR Part 60, Appendix A. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

The ton per year emission limitation was developed by multiplying the hourly allowable H_2SO_4 emission limitation (6.7E-05 lb/hr) by the maximum annual hours of operation (500 hours), and then dividing by 2,000 pounds per ton. Therefore, compliance with the annual limitation shall be demonstrated if compliance with the hourly limitation and operating hours restriction is shown.

g. <u>Emission Limitation</u>:

CO_2e emissions shall not exceed 90.0 tons per rolling, 12-month period.

<u>Applicable Compliance Method</u>:

This emission limitation was established to reflect the potential to emit for this emissions unit by calculating the sum of the maximum capacity (311 hp) by the emission factors for CO_2, N_2O, and CH_4, multiplied by the global warming potentials for CO_2, N_2O, and CH_4 (1, 298, and 25, respectively from Table A-1 to Subpart of 40 CFR 98). Multiply the sum by the maximum annual hours of operation (500 hrs/yr) and divide by 2,000 pounds per ton. The CO_2 emission factor was obtained from AP-42 Table 3.3-1 dated 10/96 (1.15 lb/hp-hr). The N_2O emission factor was obtained from Table C-2 to Subpart C of 40 CFR 98 (0.6 g/MMBtu). The CH_4 emission factor was obtained from AP-42 Table 3.3-1 dated 10/96 (2.47E-03 lb TOC/hp-hr (0.09 lb CH_4/lb TOC)= 2.223E-04 lb CH_4/hp-hr, this table did not include an estimate of how much methane comprises the TOC emission factor, so the value of 9% from AP-42 Table 3.4-1 dated 10/96 was used).

$$(311\,hp)x\left[\left(1.15\frac{lb}{hp-hr}(1)\right)+\left(\left(0.6\frac{g}{mmBtu}\right)\left(7000\frac{Btu}{hp-hr}\right)\left(\frac{mmBtu}{1E06Btu}\right)\left(\frac{lb}{454g}\right)(298)\right)+\left(2.223E-04\frac{lb}{(hp-hr)}\right)(25)\right]x\left(500\frac{hrs}{hr}\right)x\left(\frac{ton}{2{,}000lb}\right)=90.0\,tons/yr$$

Since the CO_2e emissions are estimated to consist of more than 99% CO_2, compliance with this emission limitation will be assumed provided that the lb/hp-hr CO_2 emission rate does not exceed 1.15 lb/hp-hr. If required, the permittee shall conduct emissions testing using Methods 1, 2, 3A and 4 of 40 CFR Part 60, Appendix A to determine the lb/hp-hr CO_2 emission rate. Alternative U.S. EPA-approved test methods may be used with prior approval from the Ohio EPA.

h. <u>Emission Limitation</u>:

The permittee shall only combust ULSD fuel in this emissions unit meeting the following standard: 15 ppm maximum sulfur content.

Applicable Compliance Method:

Compliance shall be demonstrated based upon the record keeping requirements specified in d)(2).

i. Emission Limitation:

The permittee shall only combust ULSD fuel in this emissions unit meeting the following standard: a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent.

Applicable Compliance Method:

Compliance shall be demonstrated based upon the record keeping requirements specified in d)(2) and d)(3).

j. Emission Limitation:

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

Applicable Compliance Method:

If required, the permittee shall demonstrate compliance based upon an emission test performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9.

k. Emission Limitation:

NMHC + NO_x emissions shall not exceed 4.0 g/kW-hr (3.0 g/hp-hr).

CO emissions shall not exceed 3.5 g/kW-hr (2.6 g/hp-hr).

PM emissions shall not exceed 0.20 g/kW-hr (0.15 g/hp-hr).

Applicable Compliance Method:

According to 40 CFR 60.4211(c), the permittee shall demonstrate compliance with these emission limitations by purchasing an engine certified to the emission standards in 40 CFR 60.4205(c) for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g).

g) Miscellaneous Requirements

(1) None.

5. Emissions Unit Group – P005 and P006

EU ID	Operations, Property and/or Equipment Description
P005	8-Cell Wet Cooling Tower equipped with a high efficiency drift eliminator.
P006	8-Cell Wet Cooling Tower equipped with a high efficiency drift eliminator.

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) None.

b) Applicable Emissions Limitations and/or Control Requirements

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

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	See b)(2)a through b)(2)c.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the $PM_{2.5}$ or PM_{10} emissions from this air contaminant source since the potential to emit is less than 10 tons per year. See b)(2)d.
c.	OAC rules 3745-31-10 through 20 (Prevention of Significant Deterioration of Air Quality)	Particulate matter emissions less than 10 microns in diameter (PM_{10}) shall not exceed 1.33 pounds per hour (lbs/hr) and 5.85 tons per rolling, 12-month period. Particulate matter emissions less than 2.5 microns in diameter ($PM_{2.5}$) shall not exceed 0.534 lb/hr and 2.34 tons per rolling, 12-month period. The permittee shall install a drift eliminator with a maximum drift rate of 0.0005% on this emissions unit. Visible particulate emissions shall not exceed 10% opacity as a 6-minute average. The presence of condensed

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		water vapor shall not be deemed a violation for failure of stack emissions meeting this visible emission limitation. See c)(1)
d.	OAC rule 3745-17-07(A)(1)	See b)(2)e.
e.	OAC rule 3745-17-11(B)	See b)(2)e.

(2) Additional Terms and Conditions

a. All requirements specified in this Section of the permit for Emissions Unit Group P005 and P006 apply to each Wet Cooling Tower (P005 and P006) unless a combined requirement is otherwise specified.

b. Compliance with the requirements of this rule for PM_{10} and $PM_{2.5}$ emissions includes compliance with the requirements of OAC rules 3745-31-10 through 20.

c. The BAT emission limits apply until U.S. EPA approves Ohio Administrative Code (OAC) paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) into the Ohio State Implementation Plan (SIP).

d. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than ten tons per year BAT exemption) as part of the Ohio SIP.

e. The emission limitation required by this applicable rule is less stringent than the emission limitation established pursuant to OAC rules 3745-31-10 through 20.

c) Operational Restrictions

(1) The permittee shall maintain the total dissolved solids (TDS) concentration of the cooling water less than or equal to 4,500 milligrams per liter (mg/l).

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall properly install, operate and maintain a conductivity meter or other equipment to continuously monitor and record the TDS concentration of the cooling tower water. The monitoring devices shall be installed, calibrated, operated and maintained in accordance with the manufacturer's recommendations, instructions and operating manuals.

(2) Since the TDS data measured by the conductivity meter or other equipment is based on a correlation between conductivity and TDS, an exceedance measured by the conductivity meter or equivalent is not a violation of the TDS operational restriction, but rather serves as an indicator to initiate corrective action by the permittee to reduce the TDS concentration.

e) Reporting Requirements

(1) The permittee shall submit quarterly deviation (excursion) reports that identify all hourly TDS readings in excess of 4,500 mg/l. The reports shall identify corrective action taken to reduce the TDS concentration.

The quarterly deviation (excursion) reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit

(2) Prior to startup, the permittee shall submit written documentation provided by the vendor/manufacturer of the maximum drift rate of 0.0005% for the drift eliminator and the premise, basis and justification for the drift rate.

(3) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

a. Emission Limitation:

PM_{10} emissions shall not exceed 1.33 lbs/hr and 5.85 tons per rolling, 12-month period.

Applicable Compliance Method:

The lb/hr PM_{10} emission limitation is based on multiplying the maximum re-circulating water flow rate (118,441 gal/min) by the maximum TDS concentration (4,500 mg/l) multiplied by 3.785 l/gal multiplied by the decimal fraction drift rate per flow (0.0005/100) divided by [(1000 mg/g)(60 sec/min)(453.6 g/lb)/(3600 sec/hr)].

The annual emission limitation is based on multiplying the hourly emission limitation (1.33 lbs/hr) by the maximum annual hours of operation (8,760 hrs/yr) and dividing by (2,000 lbs/ton).

Compliance with the hourly and annual emission limitation will be assumed provided that the TDS concentration recorded in d) remains below 4,500 mg/l.

b. Emission Limitation:

$PM_{2.5}$ emissions shall not exceed 0.534 lb/hr and 2.34 tons per rolling, 12-month period.

Applicable Compliance Method:

Per permit application, $PM_{2.5}$ is 40% of PM_{10} as calculated above. The permittee calculated the PM_{10} fraction using AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.

The annual emission limitation is based on multiplying the hourly emission limitation (0.534 lb/hr) by the maximum annual hours of operation (8,760 hrs/yr) and dividing by (2,000 lbs/ton).

Compliance with the hourly and annual emissions limitation will be assumed provided that the TDS concentration recorded in d) remains below 4,500 mg/l.

c. Emission Limitation:

The permittee shall install a drift eliminator with a maximum drift rate of 0.0005% on this emissions unit.

Applicable Compliance Method:

Manufacturer's emissions data shall be used to demonstrate compliance with this limitation.

Within 90 days of startup, the permittee shall submit to Ohio EPA's Northeast District Office written documentation provided by the vendor/manufacturer of the maximum drift rate of 0.0005% for the drift eliminator and the premise, basis and justification for the drift rate.

d. Emission Limitation:

The permittee shall maintain the TDS concentration of the cooling water less than or equal to 4,500 mg/l.

Applicable Compliance Method:

Compliance shall be demonstrated based upon the monitoring and record keeping requirements specified in d)(1) and d)(2).

If required, compliance shall be demonstrated using test procedures that conform to regulation 40 CFR Part 136, "Test Procedures for the Analysis of Pollutants". Alternative U.S. EPA-approved test methods may be used with prior written approval from the Ohio EPA.

e. Emission Limitation:

Visible particulate emissions shall not exceed 10% opacity as a 6-minute average. The presence of condensed water vapor shall not be deemed a violation for failure of stack emissions meeting this visible emission limitation.

Applicable Compliance Method:

If required, compliance with the stack visible particulate emission limitation shall be demonstrated through visible emission observations performed in accordance with the methods and procedures specified in 40 CFR Part 60, Appendix A, Method 9.

g) Miscellaneous Requirements

(1) None.