MINNESOTA POLLUTION CONTROL AGENCY

Air Individual Permit
Major Amendment
13900010-105

Permittee: **Xcel Energy - Blue Lake**

Facility name: **Xcel Energy - Blue Lake**
1200 70th Street S
Shakopee, MN 55379-2100
Scott County

Operating permit issuance date: December 24, 2019

Expiration date: December 24, 2024
* All Title I Conditions do not expire

Major Amendment: August 7, 2024

Permit characteristics: Federal; Part 70/ Major for NSR; NSR Authorization

The emission units, control equipment and emission stacks at the stationary source authorized in this permit amendment are as described in the submittals listed in the Permit Applications Table.

This permit amendment supersedes Air Emission Permit No. 13900010-104 and authorizes the Permittee to operate and construct the stationary source at the address listed above unless otherwise noted in the permit. The Permittee must comply with all the conditions of the permit. Any changes or modifications to the stationary source must be performed in compliance with Minn. R. 7007.1150 to 7007.1500. Terms used in the permit are as defined in the state air pollution control rules unless the term is explicitly defined in the permit.

Unless otherwise indicated, all the Minnesota rules cited as the origin of the permit terms are incorporated into the SIP under 40 CFR § 52.1220 and as such are enforceable by U.S. Environmental Protection Agency (EPA) Administrator or citizens under the Clean Air Act.

Signature: Toni Volkmeier

This document has been electronically signed.

for Steven S. Pak, P.E., Manager
Air Quality Permits Section
Industrial Division

for the Minnesota Pollution Control Agency

Table of Contents

Page

1. Permit applications table 3
2. Where to send submittals 4
3. Facility description 5
4. Summary of subject items 6
5. Limits and other requirements 11
6. Submittal/action requirements 95
7. Appendices 117
   - Appendix A. Insignificant activities and general applicable requirements 117
   - Appendix B. Acid Rain Permit Renewal Application 118
   - Appendix C. 40 CFR Part 60, Subpart A—General Provisions 122
   - Appendix D. 40 CFR Part 63, Subpart A—General Provisions 245
   - Appendix E. 40 CFR Part 63, Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines 343
   - Appendix F. Transport Rule (TR) Trading Program Title V Requirements 413
   - Appendix G. 40 CFR Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines 416
   - Appendix H. Fugitive Dust Control Plan 448
   - Appendix I. General Public Preclusion Plan 452
   - Appendix J. Modeling Parameters 454
   - Appendix K. 40 CFR Part 60, Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines 460

1. Permit applications table

Title description	Application receipt date	Action number
Major Amendment	11/03/2023 supplemental information received 06/05/2024	13900010-105
Administrative Amendment	03/16/2020	13900010-104
Part 70 Reissuance	03/13/2018, with supplemental information received 07/15/2019 and 09/16/2019	13900010-101

2. Where to send submittals

Send submittals that are required to be submitted to the EPA regional office to:

Chief Air Enforcement
Air and Radiation Branch
EPA Region V
77 West Jackson Boulevard
Chicago, Illinois 60604

Each submittal must be postmarked or received by the date specified in the applicable Table. Those submittals required by Minn. R. 7007.0100 to 7007.1850 must be certified by a responsible official, defined in Minn. R. 7007.0100, subp. 21. Other submittals shall be certified as appropriate if certification is required by an applicable rule or permit condition.

Send submittals that are required by the Acid Rain Program to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue NW (6204M)
Washington, D.C. 20460

Send any application for a permit or permit amendment to:

Fiscal Services – 6th Floor
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194

Also, where required by an applicable rule or permit condition, send to the Permit Document Coordinator notices of:

a. Accumulated insignificant activities
b. Installation of control equipment
c. Replacement of an emissions unit, and
d. Changes that contravene a permit term

Unless another person is identified in the applicable Table, send all other submittals to:

AQ Compliance Tracking Coordinator
Industrial Division
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, Minnesota 55155-4194

Or

Email a signed and scanned PDF copy to:
submitstacktest.pca@state.mn.us
(for submittals related to stack testing)
AQRoutineReport.PCA@state.mn.us
(for other compliance submittals)
(See complete email instructions in "Routine Air Report Instructions Letter" at https://www.pca.state.mn.us/sites/default/files/aq-f6-15.pdf)

3. Facility description

The Xcel Energy - Blue Lake (Facility) is located at 1200 70th Street S, Shakopee, Scott County, Minnesota.

The Xcel Energy (Permittee) Blue Lake Generating Plant (facility) is an electric generation peaking plant composed of six simple cycle stationary combustion turbine (CT) generators. Four of the CTs were manufactured by Turbodyne and installed in the 1970s. Three are rated at 50 Megawatts (MWe) each, and one is rated at 55 MWe. They are all fired with distillate fuel oil No. 2.

Two General Electric CTs rated at 174 MWe each and fired with natural gas were installed at the facility in 2004 and are equipped with dry low-NOx combustors to inhibit NOx formation. The Permittee also operates an emergency generator located in the substation.

The main pollutants are products of combustion such as nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC), particulate matter (PM), particulate matter less than ten microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), hazardous air pollutants (HAPs), and greenhouse gases (GHG or CO_2e).

This permit action is a major amendment and will add three engine generators rated at 9.37 Megawatts (MWe) each, five emergency generators, three rated at 750 kilowatts (kW) and two rated at 550 kW, two fuel oil tanks, and a paved roads fugitive source. The amendment will also revise limits on the existing natural gas fired turbines to ensure availability during peak demand and decommission the four oil fired turbines at the facility. Oxygen continuous emissions monitors will be added for the two natural gas fired turbines and selective catalytic reduction and oxidation catalyst controls will be added for the three engine generators.

4. Summary of subject items

SI ID: Description	Relationship type	Related SI ID: Description
TFAC 1: Xcel Energy - Blue Lake		
ACTV 1: All IAs		
COMG 2: NG-Fired GE 7FA Combustion Turbines	has members	EQUI 7, EQUI 8
COMG 4: NOx CEMS for EQUI 7 and EQUI 8	has members	EQUI 9, EQUI 11
COMG 5: HAPs Limits	has members	EQUI 1, EQUI 2, EQUI 3, EQUI 4, EQUI 7, EQUI 8, EQUI 23, EQUI 24, EQUI 25, EQUI 26, EQUI 27, EQUI 28, EQUI 29, EQUI 43
COMG 7: CO CEMS for EQUI 7 and EQUI 8	has members	EQUI 10, EQUI 12
COMG 8: Transport Rule/CSAPR for EQUI 1 through 4 and NG CTs EQUI 7 and 8	has members	EQUI 1, EQUI 2, EQUI 3, EQUI 4, EQUI 7, EQUI 8
COMG 9: O2 CEMS for EQUI 7 and EQUI 8	has members	EQUI 30, EQUI 31
EQUI 1: Combustion Turbine 1 (50 MW) - Turbine	sends to	STRU 16: Combustion Turbine 1
EQUI 2: Combustion Turbine 2 (50 MW) - Turbine	sends to	STRU 17: Combustion Turbine 2
EQUI 3: Combustion Turbine 3 (50 MW) - Turbine	sends to	STRU 18: Combustion Turbine 3
EQUI 4: Combustion Turbine 4 (55 MW) - Turbine	sends to	STRU 19: Combustion Turbine 4
EQUI 5: Emergency Engine/Generator	sends to	STRU 14: Substation engine/generator stack
EQUI 7: GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	is monitored by	EQUI 9: NOx CEMS for EQUI 7
EQUI 7: GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	is monitored by	EQUI 10: CO CEMS for EQUI 7
EQUI 7: GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)		7
EQUI 7: GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	sends to	EQUI 16: Stackvision Data Acquisition System
EQUI 7: GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	is monitored by	EQUI 21: Fuel usage parametric monitor for EQUI 7
EQUI 7: GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	is monitored by	EQUI 30: EQUI 7 O2 CEMS (diluent)
EQUI 7: GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	sends to	STRU 12: Combustion Turbine 7 (EQUI 7)
EQUI 8: GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	is monitored by	EQUI 11: NOx CEMS for EQUI 8
EQUI 8: GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	is monitored by	EQUI 12: CO CEMS for EQUI 8
EQUI 8: GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	sends to	EQUI 16: Stackvision Data Acquisition System
EQUI 8: GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	is monitored by	EQUI 22: Fuel usage parametric monitor for EQUI 8
EQUI 8: GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	is monitored by	EQUI 31: EQUI 8 O2 CEMS (diluent)
EQUI 8: GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	sends to	STRU 13: Combustion Turbine 8 (EQUI 8)
EQUI 9: NOx CEMS for EQUI 7		

SI ID: Description	Relationship type	Related SI ID: Description
EQUI 10: CO CEMS for EQUI 7		
EQUI 11: NOx CEMS for EQUI 8		
EQUI 12: CO CEMS for EQUI 8		
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 9: NOx CEMS for EQUI 7
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 10: CO CEMS for EQUI 7
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 11: NOx CEMS for EQUI 8
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 12: CO CEMS for EQUI 8
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 21: Fuel usage parametric monitor for EQUI 7
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 22: Fuel usage parametric monitor for EQUI 8
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 30: EQUI 7 O2 CEMS (diluent)
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 31: EQUI 8 O2 CEMS (diluent)
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 34: EQUI 23 SCR and Oxidation Catalyst Inlet Temperature
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 35: EQUI 23 SCR and Oxidation Catalyst Inlet Pressure
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 36: EQUI 23 SCR and Oxidation Catalyst Outlet Pressure
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 37: EQUI 24 SCR and Oxidation Catalyst Inlet Temperature
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 38: EQUI 24 SCR and Oxidation Catalyst Inlet Pressure
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 39: EQUI 24 SCR and Oxidation Catalyst Outlet Pressure
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 40: EQUI 25 SCR and Oxidation Catalyst Inlet Temperature
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 41: EQUI 25 SCR and Oxidation Catalyst Inlet Pressure
EQUI 16: Stackvision Data Acquisition System	receives from	EQUI 42: EQUI 25 SCR and Oxidation Catalyst Outlet Pressure
EQUI 23: Engine Generator 1	sends to	STRU 24: EQUI 23 Stack
EQUI 23: Engine Generator 1	is controlled by	TREA 1: Oxidation Catalyst
EQUI 23: Engine Generator 1	is controlled by	TREA 2: Selective Catalytic Reduction
EQUI 24: Engine Generator 2	sends to	STRU 25: EQUI 24 Stack
EQUI 24: Engine Generator 2	is controlled by	TREA 3: Oxidation Catalyst
EQUI 24: Engine Generator 2	is controlled by	TREA 4: Selective Catalytic Reduction
EQUI 25: Engine Generator 3	sends to	STRU 26: EQUI 25 Stack
EQUI 25: Engine	is controlled	TREA 5:

SI ID: Description	Relationship type	Related SI ID: Description
Generator 3	by	Oxidation Catalyst
EQUI 25: Engine Generator 3	is controlled by	TREA 6: Selective Catalytic Reduction
EQUI 26: Emergency Generator 2	sends to	STRU 27: EQUI 26 Stack
EQUI 27: Emergency Generator 3	sends to	STRU 28: EQUI 27 Stack
EQUI 28: Emergency Generator 4	sends to	STRU 29: EQUI 28 Stack
EQUI 29: Emergency Generator 5	sends to	STRU 30: EQUI 29 Stack
EQUI 30: EQUI 7 O2 CEMS (diluent)		
EQUI 31: EQUI 8 O2 CEMS (diluent)		
EQUI 32: Diesel Tank #1		
EQUI 33: Diesel Tank #2		
EQUI 34: EQUI 23 SCR and Oxidation Catalyst Inlet Temperature		
EQUI 35: EQUI 23 SCR and Oxidation Catalyst Inlet Pressure		
EQUI 36: EQUI 23 SCR and Oxidation Catalyst Outlet Pressure		
EQUI 37: EQUI 24 SCR and Oxidation Catalyst Inlet Temperature		
EQUI 38: EQUI 24 SCR and Oxidation Catalyst Inlet Pressure		
EQUI 39: EQUI 24 SCR and Oxidation Catalyst Outlet Pressure		
EQUI 40: EQUI 25 SCR and Oxidation Catalyst Inlet Temperature		
EQUI 41: EQUI 25 SCR and Oxidation Catalyst Inlet Pressure		
EQUI 42: EQUI 25 SCR and Oxidation Catalyst Outlet Pressure		
EQUI 43: Emergency	sends to	STRU 38: EQUI

SI ID: Description	Relationship type	Related SI ID: Description
Generator 6		43 Stack
FUGI 1: Engine generator fuel deliveries on paved road		
STRU 1: Substation Generator Building		
STRU 2: Foam House		
STRU 3: Gas Turbine Building		
STRU 4: Operations Building		
STRU 5: Fuel Forwarding Building		
STRU 6: Fire Foam Equipment Building		
STRU 7: Fuel Oil Tank		
STRU 8: Fuel Oil Tank		
STRU 9: Warehouse		
STRU 10: Gas Turbine 7 Structure		
STRU 11: Gas Turbine 8 Structure		
STRU 12: Combustion Turbine 7 (EQUI 7)		
STRU 13: Combustion Turbine 8 (EQUI 8)		
STRU 14: Substation engine/generator stack		
STRU 16: Combustion Turbine 1		
STRU 17: Combustion Turbine 2		
STRU 18: Combustion Turbine 3		
STRU 19: Combustion Turbine 4		
STRU 20: Substation controls building		
STRU 24: EQUI 23 Stack		
STRU 25: EQUI 24 Stack		
STRU 26: EQUI 25 Stack		
STRU 27: EQUI 26 Stack		
STRU 28: EQUI 27 Stack		

SI ID: Description	Relationship type	Related SI ID: Description
STRU 29: EQUI 28 Stack		
STRU 30: EQUI 29 Stack		
STRU 31: Rice #1 Equipment		
STRU 32: Rice #2 Equipment		
STRU 33: Rice #3 Equipment		
STRU 34: Rice Building Tier 1		
STRU 35: Rice Building Tier 2		
STRU 36: West Fuel Oil Tank #1		
STRU 37: West Fuel Oil Tank #2		
STRU 38: EQUI 43 Stack		
TREA 1: Oxidation Catalyst	sends to	EQUI 16: Stackvision Data Acquisition System
TREA 1: Oxidation Catalyst	is monitored by	EQUI 34: EQUI 23 SCR and Oxidation Catalyst Inlet Temperature
TREA 1: Oxidation Catalyst	is monitored by	EQUI 35: EQUI 23 SCR and Oxidation Catalyst Inlet Pressure
TREA 1: Oxidation Catalyst	is monitored by	EQUI 36: EQUI 23 SCR and Oxidation Catalyst Outlet Pressure
TREA 2: Selective Catalytic Reduction	sends to	EQUI 16: Stackvision Data Acquisition System
TREA 2: Selective Catalytic Reduction	is monitored by	EQUI 34: EQUI 23 SCR and Oxidation Catalyst Inlet Temperature
TREA 2: Selective Catalytic Reduction	is monitored by	EQUI 35: EQUI 23 SCR and Oxidation Catalyst Inlet Pressure
TREA 2: Selective Catalytic Reduction	is monitored by	EQUI 36: EQUI 23 SCR and Oxidation Catalyst Outlet Pressure
TREA 2: Selective Catalytic Reduction	is controlled in series by	TREA 1: Oxidation Catalyst
TREA 3: Oxidation Catalyst	sends to	EQUI 16: Stackvision Data Acquisition System
TREA 3: Oxidation Catalyst	is monitored by	EQUI 37: EQUI 24 SCR and Oxidation Catalyst Inlet Temperature
TREA 3: Oxidation Catalyst	is monitored by	EQUI 38: EQUI 24 SCR and Oxidation Catalyst Inlet Pressure
TREA 3: Oxidation Catalyst	is monitored by	EQUI 39: EQUI 24 SCR and Oxidation Catalyst Outlet Pressure
TREA 4: Selective Catalytic Reduction	sends to	EQUI 16: Stackvision Data Acquisition System
TREA 4: Selective Catalytic Reduction	is monitored by	EQUI 37: EQUI 24 SCR and Oxidation Catalyst Inlet Temperature
TREA 4: Selective Catalytic Reduction	is monitored by	EQUI 38: EQUI 24 SCR and Oxidation Catalyst Inlet Pressure
TREA 4: Selective Catalytic Reduction	is monitored by	EQUI 39: EQUI 24 SCR and

SI ID: Description	Relationship type	Related SI ID: Description
		Oxidation Catalyst Outlet Pressure
TREA 4: Selective Catalytic Reduction	is controlled in series by	TREA 3: Oxidation Catalyst
TREA 5: Oxidation Catalyst	sends to	EQUI 16: Stackvision Data Acquisition System
TREA 5: Oxidation Catalyst	is monitored by	EQUI 40: EQUI 25 SCR and Oxidation Catalyst Inlet Temperature
TREA 5: Oxidation Catalyst	is monitored by	EQUI 41: EQUI 25 SCR and Oxidation Catalyst Inlet Pressure
TREA 5: Oxidation Catalyst	is monitored by	EQUI 42: EQUI 25 SCR and Oxidation Catalyst Outlet Pressure
TREA 6: Selective Catalytic Reduction	sends to	EQUI 16: Stackvision Data Acquisition System
TREA 6: Selective Catalytic Reduction	is monitored by	EQUI 40: EQUI 25 SCR and Oxidation Catalyst Inlet Temperature
TREA 6: Selective Catalytic Reduction	is monitored by	EQUI 41: EQUI 25 SCR and Oxidation Catalyst Inlet Pressure
TREA 6: Selective Catalytic Reduction	is monitored by	EQUI 42: EQUI 25 SCR and Oxidation Catalyst Outlet Pressure
TREA 6: Selective Catalytic Reduction	is controlled in series by	TREA 5: Oxidation Catalyst

5. Limits and other requirements

Requirement number	Requirement and citation
TFAC 1	**Xcel Energy - Blue Lake**
5.1.1	Comply with all acid rain requirements. These are included in Section 5 of the permit and also in the acid rain permit application attached as Appendix B. [40 CFR pt. 72, 40 CFR pt. 73, 40 CFR pt. 75, 40 CFR pt. 76, Minn. R. 7007.1075]
5.1.2	Emissions from the stationary source cannot exceed any allowances that the source lawfully holds under federal acid rain regulations, except as allowed by Minn. R. 7007.0800, subp. 7. [Minn. R. 7007.0800, subp. 7]
5.1.3	Keep the certificate of representation, all emissions monitoring information, copies of all reports, compliance certifications and related submissions and all records made or required under the Acid Rain Program on site for a period of 5 years from the date the document was created. [40 CFR 72.9(f), Minn. R. 7007.1075]
5.1.4	Hold allowances after January 1, 2001, as of the allowance transfer deadline, in the affected unit's compliance subaccount. Allowances may not be less than the total annual emissions of sulfur dioxide from the previous calendar year from the unit. [40 CFR 72.9(c), Minn. R. 7007.1075]
5.1.5	Permit Appendices: This permit contains appendices as listed in the permit Table of Contents. The Permittee shall comply with all requirements contained in Appendix A - Insignificant Activities and General Applicable Requirements; Appendix B - Acid Rain Permit Renewal Application; Appendix C - 40 CFR Part 60 Subpart A, General Provisions; Appendix D - 40 CFR Part 63, subp. A, General Provisions; Appendix E - 40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines; Appendix F - Transport Rule (TR) Trading Program Title V Requirements; Appendix G - 40 CFR Part 60 Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Appendix H - Fugitive Dust Control Plan; Appendix I - General Public Preclusion Plan; Appendix K - 40 CFR Part 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. Modeling parameters in Appendix J - Modeling Parameters are included for reference only as described elsewhere in this permit. [Minn. R. 7007.0800, subp. 2(A) & (B)]
5.1.6	The Permittee must comply with Minn. Stat. 116.385. The Permittee may not use trichloroethylene at its permitted facility including in any manufacturing, processing, or cleaning processes, except as described in Minn. Stat. 116.385, subd. 2(b) and 4. This is a state-only requirement and is not enforceable by the U.S. Environmental Protection Agency (EPA) Administrator and citizens under the Clean Air Act. [Minn. R. 7007.0100, subp. 7(X), Minn. Stat. 116.385]
5.1.7	PERMIT SHIELD: Subject to the limitations in Minn. R. 7007.1800, compliance with the conditions of this permit shall be deemed compliance with the specific provision of the applicable requirement identified in the permit as the basis of each condition. Subject to the limitations of Minn. R. 7007.1800 and 7017.0100, subp. 2, notwithstanding the conditions of this permit specifying compliance practices for applicable requirements, any person (including the Permittee) may also use other credible evidence to establish compliance or noncompliance with applicable requirements. This permit shall not alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance. [Minn. R. 7007.1800(A)(2)]
5.1.8	Comply with Fugitive Emission Control Plan: The Permittee shall follow the actions and recordkeeping specified in the fugitive dust control plan in Appendix H of this permit. If the Commissioner determines the Permittee is out of compliance with Minn. R. 7011.0150 or the fugitive control plan, then the Permittee may be required to amend the control plan and/or to install and operate particulate matter ambient monitors as requested by the Commissioner. [Minn. R. 7007.0800, subp.

Requirement number	Requirement and citation
	2(A), Minn. R. 7009.0020, Minn. R. 7011.0150, Minn. Stat. 116.07, subd. 4a(a)]
5.1.9	The Permittee shall comply with National Primary and Secondary Ambient Air Quality Standards, 40 CFR pt. 50, and the Minnesota Ambient Air Quality Standards, Minn. R. 7009.0010 to 7009.0090. Compliance shall be demonstrated upon written request by the MPCA. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.10	Circumvention: Do not install or use a device or means that conceals or dilutes emissions, which would otherwise violate a federal or state air pollution control rule, without reducing the total amount of pollutant emitted. [Minn. R. 7011.0020]
5.1.11	The Permittee must at all times properly operate and maintain the facilities and systems of treatment and control and the appurtenances related to them that are installed or used by the Permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. [Minn. R. 7007.0800, subp. 16(J)]
5.1.12	Operation and Maintenance Plan: Retain at the stationary source an operation and maintenance plan for all air pollution control equipment. At a minimum, the O & M plan shall identify all air pollution control equipment and control practices and shall include a preventative maintenance program for the equipment and practices, a description of (the minimum but not necessarily the only) corrective actions to be taken to restore the equipment and practices to proper operation to meet applicable permit conditions, a description of the employee training program for proper operation and maintenance of the control equipment and practices, and the records kept to demonstrate plan implementation. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subp. 16(J)]
5.1.13	Operation Changes: In any shutdown, breakdown, or deviation the Permittee must immediately or as soon as possible considering plant and personnel safety take all practical steps to modify operations to reduce the emission of any regulated air pollutant. No emissions units that have an unreasonable shutdown or breakdown frequency of process or control equipment are permitted to operate. [Minn. R. 7019.1000, subp. 4]
5.1.14	Fugitive Emissions: Do not cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne. Comply with all other requirements listed in Minn. R. 7011.0150. [Minn. R. 7011.0150]
5.1.15	Noise: The Permittee shall comply with the noise standards set forth in Minn. R. 7030.0010 to 7030.0080 at all times during the operation of any emission units. This is a state only requirement and is not enforceable by the EPA Administrator or citizens under the Clean Air Act. [Minn. R. 7030.0010-7030.0080]
5.1.16	Inspections: The Permittee shall comply with the inspection procedures and requirements as found in Minn. R. 7007.0800, subp. 9(A). [Minn. R. 7007.0800, subp. 9(A)]
5.1.17	The Permittee shall comply with the General Conditions listed in Minn. R. 7007.0800, subp. 16. [Minn. R. 7007.0800, subp. 16]
5.1.18	Performance Testing: Conduct all performance tests in accordance with Minn. R. ch. 7017 unless otherwise noted in this permit. [Minn. R. ch. 7017]
5.1.19	Performance Test Notifications and Submittals: Performance Test Notification and Plan: due 30 days before each Performance Test Performance Test Pre-test Meeting: due seven days before each Performance Test Performance Test Report: due 45 days after each Performance Test The Notification, Test Plan, and Test Report must be submitted in a format specified by the commissioner. [Minn. R. 7017.2017, Minn. R. 7017.2030, subps. 1-4, Minn. R. 7017.2035, subps. 1-2]
5.1.20	Limits set as a result of a performance test (conducted before or after permit issuance) apply until

Requirement number	Requirement and citation
	superseded as stated in the MPCA's Notice of Compliance letter granting preliminary approval. Preliminary approval is based on formal review of a subsequent performance test on the same unit as specified by Minn. R. 7017.2025, subp. 3. The limit is final upon issuance of a permit amendment incorporating the change. [Minn. R. 7017.2025, subp. 3]
5.1.21	Monitoring Equipment Calibration - The Permittee shall either: 1. Calibrate or replace required monitoring equipment every 12 months; or 2. Calibrate at the frequency stated in the manufacturer's specifications. For each monitor, the Permittee shall maintain a record of all calibrations, including the date conducted, and any corrective action that resulted. The Permittee shall include the calibration frequencies, procedures, and manufacturer's specifications (if applicable) in the Operations and Maintenance Plan. Any requirements applying to continuous emission monitors are listed separately in this permit. [Minn. R. 7007.0800, subp. 4(D)]
5.1.22	Operation of Monitoring Equipment: Unless noted elsewhere in this permit, monitoring a process or control equipment connected to that process is not necessary during periods when the process is shutdown, or during checks of the monitoring systems, such as calibration checks and zero and span adjustments. If monitoring records are required, they should reflect any such periods of process shutdown or checks of the monitoring system. [Minn. R. 7007.0800, subp. 4(D)]
5.1.23	Recordkeeping: Retain all records at the stationary source, unless otherwise specified within this permit, for five (5) years from the date of monitoring, sample, measurement, or report. Records which must be retained at this location include all calibration and maintenance records, all original recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records must conform to the requirements listed in Minn. R. 7007.0800, subp. 5(A). [Minn. R. 7007.0800, subp. 5(C)]
5.1.24	Recordkeeping: Maintain records describing any insignificant modifications (as required by Minn. R. 7007.1250, subp. 3) or changes contravening permit terms (as required by Minn. R. 7007.1350, subp. 2), including records of the emissions resulting from those changes. [Minn. R. 7007.0800, subp. 5(B)]
5.1.25	If the Permittee determines that no permit amendment or notification is required prior to making a change, the Permittee must retain records of all calculations required under Minn. R. 7007.1200. For expiring permits, these records shall be kept for a period of five years from the date the change was made or until permit reissuance, whichever is longer. The records shall be kept at the stationary source for the current calendar year of operation and may be kept at the stationary source or office of the stationary source for all other years. The records may be maintained in either electronic or paper format. [Minn. R. 7007.1200, subp. 4]
5.1.26	These following 40 CFR 52.21(r)(6) requirements apply if a reasonable possibility (RP) as defined in 40 CFR 52.21(r)(6)(vi) exists that a proposed project, analyzed using the actual-to-projected-actual (ATPA) test (either by itself or as part of the hybrid test at 40 CFR 52.21(a)(2)(iv)(f)) and found to not be part of a major modification, may result in a significant emissions increase (SEI). If the ATPA test is not used for the project, or if there is no RP that the proposed project could result in a SEI, these requirements do not apply to that project. The Permittee is only subject to the Preconstruction Documentation requirement for a project where a RP occurs only within the meaning of 40 CFR 52.21(r)(6)(vi)(b). Even though a particular modification is not subject to New Source Review (NSR), or where there isn't a RP that a proposed project could result in a SEI, a permit amendment, recordkeeping, or notification may still be required by Minn. R. 7007.1150 - 7007.1500. [Minn. R. 7007.0800, subp. 2(A), Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]
5.1.27	Preconstruction Documentation -- Before beginning actual construction on a project, the Permittee shall document the following:

Requirement number	Requirement and citation
	1. Project description 2. Identification of any emission unit whose emissions of an NSR pollutant could be affected 3. Pre-change potential emissions of any affected existing emission unit, and the projected post-change potential emissions of any affected existing or new emission unit. 4. A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded due to increases not associated with the modification and that the emission unit could have accommodated during the baseline period, an explanation of why the amounts were excluded, and any creditable contemporaneous increases and decreases that were considered in the determination. The Permittee shall maintain records of this documentation. [Minn. R. 7007.0800, subps. 4-5, Minn. R. 7007.1200, subp. 4, Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]
5.1.28	The Permittee shall monitor the actual emissions of any regulated NSR pollutant that could increase as a result of the project and that were analyzed using the ATPA test, and the potential emissions of any regulated NSR pollutant that could increase as a result of the project and that were analyzed using potential emissions in the hybrid test. The Permittee shall calculate and maintain a record of the sum of the actual and potential (if the hybrid test was used in the analysis) emissions of the regulated pollutant, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit of any unit associated with the project. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]
5.1.29	The Permittee must submit a report to the Agency if the annual summed (actual, plus potential if used in hybrid test) emissions differ from the preconstruction projection and exceed the baseline actual emissions by a significant amount as listed at 40 CFR 52.21(b)(23). Such report shall be submitted to the Agency within 60 days after the end of the year in which the exceedances occur. The report shall contain: a. The name and ID number of the Facility, and the name and telephone number of the Facility contact person. b. The annual emissions (actual, plus potential if any part of the project was analyzed using the hybrid test) for each pollutant for which the preconstruction projection and significant emissions increase are exceeded. c. Any other information, such as an explanation as to why the summed emissions differ from the preconstruction projection. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]
5.1.30	Shutdown Notifications: Notify the commissioner at least 24 hours in advance of a planned shutdown of any control equipment or process equipment if the shutdown would cause any increase in the emissions of any regulated air pollutant. If the Permittee does not have advance knowledge of the shutdown, the Permittee must notify the commissioner as soon as possible after the shutdown. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 3. At the time of notification, the owner or operator must inform the commissioner of the cause of the shutdown and the estimated duration. The owner or operator must notify the commissioner when the shutdown is over. [Minn. R. 7019.1000, subp. 3]
5.1.31	Breakdown Notifications: Notify the commissioner within 24 hours of a breakdown of more than one hour of any control equipment or process equipment if the breakdown causes any increase in the emissions of any regulated air pollutant. The 24-hour time period starts when the breakdown was discovered or reasonably should have been discovered by the owner or operator. However,

Requirement number	Requirement and citation
	notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 2. At the time of notification or as soon as possible thereafter, the Permittee must inform the commissioner of the cause of the breakdown and the estimated duration. The Permittee must notify the commissioner when the breakdown is over. [Minn. R. 7019.1000, subp. 2]
5.1.32	Notification of Deviations Endangering Human Health or the Environment: Immediately after discovery of the deviation or immediately after when the deviation reasonably should have been discovered, notify the commissioner either orally or by e-mail, or telephone the state duty officer at 800-422-0798 or 651-649-5451, of any deviation from permit conditions that could endanger human health or the environment. [Minn. R. 7019.1000, subp. 1]
5.1.33	Notification of Deviations Endangering Human Health or the Environment Report: Within two working days of discovery, notify the commissioner in writing of any deviation from permit conditions that could endanger human health or the environment. Include the following information in this written description: 1. the cause of the deviation; 2. the exact dates of the period of the deviation, if the deviation has been corrected; 3. whether or not the deviation has been corrected; 4. the anticipated time by which the deviation is expected to be corrected, if not yet corrected; and 5. steps taken or planned to reduce, eliminate, and prevent reoccurrence of the deviation. [Minn. R. 7019.1000, subp. 1]
5.1.34	Application for Permit Amendment: If a permit amendment is needed, submit an application in accordance with the requirements of Minn. R. 7007.1150 through Minn. R. 7007.1500. Submittal dates vary, depending on the type of amendment needed. Upon adoption of a new or amended federal applicable requirement, and if there are three or more years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150 - 7007.1500]
5.1.35	Extension Requests: The Permittee may apply for an Administrative Amendment to extend a deadline in a permit by no more than 120 days, provided the proposed deadline extension meets the requirements of Minn. R. 7007.1400, subp. 1(H). Performance testing deadlines from the General Provisions of 40 CFR pt. 60 and pt. 63 are examples of deadlines for which the MPCA does not have authority to grant extensions and therefore do not meet the requirements of Minn. R. 7007.1400, subp. 1(H). [Minn. R. 7007.1400, subp. 1(H)]
5.1.36	Within 15 days of a request from the Commissioner, the Permittee must provide a complete summary of all performance tests required at the facility including the subject item, pollutant, most recent test date (if applicable), and the date of the next test in an approved format. [Minn. R. 7007.0800, subp. 16(L)]
5.1.37	Emission Inventory Report: due on or before April 1 of each calendar year following permit issuance. Submit in a format specified by the Commissioner. [Minn. R. 7019.3000-7019.3100]
5.1.38	Emission Fees: due 30 days after receipt of an MPCA bill. [Minn. R. 7002.0005-7002.0085]
5.1.39	Modeled Parameters for NO2: The parameters used in NO2 modeling for permit number 13900010-105 are listed in Appendix J of this permit. The parameters describe the operation of the facility at maximum permitted capacity. The purpose of listing the parameters in the appendix is to provide a benchmark for future changes. [Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.40	Modeled Parameters for PM2.5: The parameters used in PM2.5 modeling for permit number 13900010-105 are listed in Appendix J of this permit. The parameters describe the operation of the facility at maximum permitted capacity. The purpose of listing the parameters in the appendix is to

Requirement number	Requirement and citation
	provide a benchmark for future changes. [Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.41	Changes to Modeled Parameters for PM2.5: Any permit amendment that affects any modeled parameter or emission rate for PM2.5 listed in Appendix J must be a major amendment. Any addition to the information documented in Appendix J requires a major amendment. Any change in the location of the ambient air boundary documented in Appendix I requires a major amendment unless the new boundary completely encompasses the original boundary documented in Appendix I. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.42	The Permittee is authorized to construct the following equipment: EQUI 23 (Engine Generator 1), EQUI 24 (Engine Generator 2), EQUI 25 (Engine Generator 3), EQUI 26 (Emergency Generator 2), EQUI 27 (Emergency Generator 3), EQUI 28 (Emergency Generator 4), EQUI 29 (Emergency Generator 5), EQUI 43 (Emergency Generator 6), TREA 1 (Oxidation Catalyst), TREA 2 (Selective Catalytic Reduction), TREA 3 (Oxidation Catalyst), TREA 4 (Selective Catalytic Reduction), TREA 5 (Oxidation Catalyst), and TREA 6 (Selective Catalytic Reduction). The construction authorization expires if construction does not commence within 18 months after Issuance of Air Emissions Permit No. 13900010-105, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. [40 CFR 52.21(r)(2)]
5.1.43	Equivalent or Better Dispersion (EBD) Modeling Triggers (Modeling Required) for PM2.5: Changes that affect any modeled parameter or emission rate listed in Appendix J, or an addition to the information documented in Appendix J, trigger the EBD Modeling Submittal requirement. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.44	EBD Modeling Submittal for PM2.5: For changes meeting the criteria in the EBD Modeling Triggers (Modeling Required) requirement, the Permittee shall submit an EBD modeling submittal in accordance with the current version of the MPCA modeling practices manual and shall wait for written approval (in the form of an issued permit amendment) before making such changes. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.45	EBD Modeling Submittal Content for PM2.5: The information submitted must include, for stack and vent sources, source emission rate, location, height, diameters, exit velocity, exit temperature, discharge direction, use of rain caps or rain hats, and, if applicable, locations and dimensions of nearby buildings. For non-stack/vent sources, this includes the source emission rate, location, size and shape, release height, and, if applicable, any emission rate scalars, and the initial lateral dimensions and initial vertical dimensions and adjacent building heights. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.46	Outdated EBD Baseline Modeling for PM2.5: Prior to conducting the EBD analysis, the Permittee shall use the current version of the MPCA modeling practices manual to determine if the Baseline Modeling (the most recent refined modeling demonstration) is outdated. If the Baseline Modeling is outdated, the Permittee shall update the Baseline Modeling to be consistent with the current version of the MPCA modeling practices manual. The updated modeling will become the new Baseline Modeling. This requirement does not require the Permittee to complete a new refined modeling demonstration using the revisions made for the EBD demonstration. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.47	EBD Modeling Results for PM2.5: The dispersion characteristics due to the revisions of the information in Appendix J must be equivalent to or better than the dispersion characteristics modeled October 27, 2023. The Permittee shall demonstrate this equivalency in the proposal. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.48	Computer Dispersion Modeling Triggers for PM2.5: The Permittee shall conduct a refined remodeling analysis in accordance with the Computer Dispersion Modeling requirements of this permit and the current version of the MPCA modeling practices manual if: (1) the results of the EBD modeling

Requirement number	Requirement and citation
	analysis do not demonstrate equivalent or better dispersion characteristics; (2) a conclusion cannot readily be made about the dispersion; (3) the criteria in the EBD Modeling Triggers requirement are met and the Permittee has previously conducted three successive EBD analyses using the same Baseline Modeling; or (4) the location of the ambient air boundary is being modified, unless the new boundary completely encompasses the original boundary documented in Appendix I. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.49	Computer Dispersion Modeling Protocol: due 180 days after receipt of written MPCA request for PM2.5 refined modeling. The Permittee shall submit a Computer Dispersion Modeling Protocol that is complete and approvable by MPCA by the deadline in this requirement. This protocol will describe the proposed modeling methodology and input data, in accordance with the current version of the MPCA modeling practices manual. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.50	Computer Dispersion Modeling Protocol: due 60 days after receipt of written MPCA request for revisions to the submitted protocol for PM2.5 modeling. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.51	Computer Dispersion Modeling Results: due 180 days after receipt of written MPCA approval of Computer Dispersion Modeling Protocol for PM2.5. The Permittee shall submit a final Computer Dispersion Modeling Report that is complete and approvable by MPCA by the deadline in this requirement. The submittal shall adhere to the current version of the MPCA modeling practices manual and the approved Computer Dispersion Modeling Protocol. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
5.1.52	General Public Preclusion Plan The Permittee shall develop and comply with a General Public Preclusion Plan. The Permittee shall maintain a copy of the Plan at the facility. The Permittee shall review the General Public Preclusion Plan annually and update if needed to reflect changes associated with controlling the ambient air boundary. The plan as of Permit Issuance is included as Appendix I. This Plan shall, at a minimum, contain the following information: 1. A map of the facility that clearly displays the ambient air boundary. The map must indicate how access is precluded for each section of the boundary and must identify all access points (including roadways, power lines, rail spurs, etc.); 2. Locations where fencing will be implemented; 3. Locations where security patrols will be implemented and the security patrol frequency; 4. Restriction signage spacing (restriction signage may include notices such as "No Trespassing," "Private Property," "Do Not Enter," or "Restricted Area"); 5. Location of remote monitoring devices; 6. Operation and maintenance requirements of remote monitoring software and devices; 7. Contingency plans for downtime for remote monitoring software and devices; and 8. A response plan for when breaches occur. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.53	Recordkeeping for Breaches of the Ambient Air Boundary Within three calendar days of each observed breach, the Permittee shall document each instance that the ambient air boundary was breached by a member of the general public, including documenting the type, location, and duration of each breach. The Permittee shall identify and, within a reasonable amount of time but not to exceed 4 days, implement measures to prevent future breaches. A breach to the ambient boundary occurs when a member of the general public accesses property identified by the Permittee as non-ambient air.

Requirement number	Requirement and citation
	The observation of a breach may be direct or indirect. A direct observation includes witnessing a member of the general public on property identified as non-ambient air. Indirect observations rely on evidence of a breach, such as a cut fence, worn paths, motorized vehicle tracks, or other signs of disturbance by a member of the general public on property identified as non-ambient air. The Permittee shall report each breach, including all steps taken or changes made to the General Public Preclusion Plan to prevent additional breaches, in the semiannual Deviations Report required by this permit. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.54	General Public Preclusion Plan - Fencing: The Permittee shall install and maintain fencing along ambient air boundary as depicted in Appendix I. The Permittee shall inspect the fence line once per quarter. The Permittee shall maintain records of inspection and required maintenance of fence line. [Minn. R. 7007.0800, subp. 4(D), Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.55	General Public Preclusion Plan - Control of Access: The Permittee shall control access at any road, trail equal to or wider than 50 inches, and all abandoned railroad grades. The Permittee shall secure these access points with a locked and/or monitored gate or other physical barrier precluding access by the general public. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.56	General Public Preclusion Plan - Security Patrols: The Permittee shall develop, operate, and maintain a security patrol plan as part of the Plan. Patrol routes shall be followed as defined in the Plan. For portions of the effective fence line where patrols are identified, the Permittee shall patrol those portions at a minimum of once per operating day. The Permittee shall maintain records of patrol routes and frequency of patrols. [Minn. R. 7007.0800, subp. 4(D), Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.57	General Public Preclusion Plan - Remote Monitoring: The Permittee shall operate and maintain remote monitoring equipment to maintain the effective fence line as depicted in Appendix I. The Permittee shall monitor at a minimum of once per day. Remote monitoring devices include but are not limited to fixed cameras and drone mounted cameras. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.1.58	General Public Preclusion Plan - Boundary Map Within 30 days after Permit Issuance or prior to initial startup of EQUIs 23-29, whichever comes first, the Permittee shall use fencing, control access points, conduct security patrols, place restriction signage, and remote monitoring as specified in Appendix I to maintain control over the fence line. Appendix I to this permit is a map that depicts the boundary at which the access of the general public can be controlled and compliance with the National Ambient Air Quality Standards (NAAQS) can be demonstrated. Appendix I identifies the forms of control the Permittee will use to restrict access to the general public along portions of the fence line. The general public does not include employees or other categories of people who have been directly authorized by the property owner to enter or remain on the property for a limited period of time and for a specific purpose. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
COMG 2	**NG-Fired GE 7FA Combustion Turbines**
5.2.1	The Permittee shall limit emissions of Carbon Monoxide <= 310.8 tons per year 12-month rolling sum. This limit applies to the combined CO emissions of EQUI 7 and EQUI 8. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
5.2.2	Monthly Recordkeeping. CO Emissions:

Requirement number	Requirement and citation
	By the 15th of the month, the Permittee shall calculate and record: 1) COMG 2 CO emissions for the previous calendar month by summing the CO emissions from EQUI 7 and EQUI 8 as determined according to requirements at EQUI 7 and EQUI 8; and, 2) Total COMG 2 CO emissions for the previous 12-month period by summing the monthly COMG 2 CO emissions data for the previous 12 months. Records shall include COMG 2 CO emissions for the previous calendar month and the previous 12-month period. [Minn. R. 7007.0800, subps. 4-5]
COMG 4	**NOx CEMS for EQUI 7 and EQUI 8**
5.3.1	If the owner or operator has installed a NOx CEMS to meet the requirements of 40 CFR Part 75 of this chapter, and is continuing to meet the ongoing requirements of 40 CFR Part 75 of this chapter, the CEMS may be used to meet the requirements of 40 CFR 60.334, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c). [40 CFR 60.334(b)(3)(iii), Minn. R. 7011.2350]
5.3.2	Additional monitoring requirements may apply. The Permittee is responsible for meeting all applicable requirements. [Minn. R. 7007.0800, subp. 4(A)]
5.3.3	Emissions Monitoring: The owner or operator shall use a CEMS to measure emissions from EQUI 7 and EQUI 8. [40 CFR 75.10(a)]
5.3.4	Monitoring Data: Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data is unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to 40 CFR 75.21 and appendix B of 40 CFR pt. 75, or backups of data from the data acquisition and handling system, or recertification, pursuant to 40 CFR 75.20. The Permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. [40 CFR 75.10(d)(1)]
5.3.5	CEMS QA/QC: The owner or operator of an affected facility shall operate, calibrate, and maintain each CEMS according to the QA/QC procedures in 40 CFR pt. 75, Appendix B as amended. [40 CFR 75.21(a)]
5.3.6	Quarterly Reports: Electronically report the data and information in 40 CFR 75.64(a), (b), and (c) to the Administrator quarterly. [40 CFR 75.64]
5.3.7	Recordkeeping: The Permittee shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. The file shall contain all information required by 40 CFR 75.57. [40 CFR 75.57]
5.3.8	Daily Calibration error (CE) Test: conduct daily CE testing on all CEMS required by the Acid Rain Program, in accordance with 40 CFR pt. 75, appendix B. [40 CFR pt. 75, Appendix B(Sect 2.1)]
COMG 5	**HAPs Limits**
5.4.1	The Permittee shall limit emissions of HAPs - Total <= 22.5 tons per year 12-month rolling sum to be calculated by the 15th day of each month for the previous 12-month period. [Title I Condition: Avoid major source under 40 CFR 63.2]
5.4.2	The Permittee shall limit emissions of HAPs - Single <= 9.0 tons per year 12-month rolling sum to be calculated by the 15th day of each month for the previous 12-month period. [Title I Condition: Avoid

Requirement number	Requirement and citation
	major source under 40 CFR 63.2]
5.4.3	HAPs: Daily Recordkeeping. On each day of operation, the Permittee shall calculate and record the total fuel usage for each emission unit EQUI 1-EQUI 4, EQUI 23-EQUI 29 and EQUI 43. See EQUI 7 and EQUI 8 daily recordkeeping requirements for EQUI 7 and EQUI 8 fuel usage. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: Avoid major source under 40 CFR 63.2]
5.4.4	Monthly Recordkeeping - Fuel Usage: By the 15th day of each month, the Permittee shall calculate and record: 1. the total fuel usage of EQUI 1-EQUI 4, EQUI 23-EQUI 29 and EQUI 43 for the previous month, and 2. the total fuel usage of EQUI 7 and EQUI 8 for the previous month. [Minn. R. 7007.0800, subps. 4-5]
5.4.5	HAPs: Monthly Recordkeeping: By the 15th day of each month the Permittee shall calculate and record the following: 1. Individual and total HAP emissions for the previous calendar month based on monthly fuel usage records and emission factors, using formulas in this permit. 2. Individual and total HAP emissions for the previous 12-month period by summing the monthly emissions data for the previous 12 months. See below for emission factor information. [Minn. R. 7007.0800, subps. 4-5]
5.4.6	HAPs: Monthly Calculation: The Permittee shall calculate each individual HAP and total HAP emissions using the following equations: COMG 5 HAP Emissions (tons/month) = Distillate fuel oil units emissions (tons per month) + Dual fuel fired units (tons per month) + Natural gas units emissions (tons per month) Distillate fuel oil units emissions (tons per month) = (DF*EF*HHVD)/2000 DF = Distillate fuel usage (gal/month) EF = HAP-specific emission factor (lbs/MMBtu) 1.29E-03 lb/MMBtu total HAP, 2.80E-04 lb/MMBtu single HAP (EQUIs 1-4) 1.06E-03 lb/MMBtu total HAP, 7.89E-05 lb/MMBtu single HAP (EQUIs 26-29, 43) HHVD = High heating value for distillate fuel oil (MMBtu/gal) Dual fuel units emissions (tons per month) = (DuF*EF)/2000 DuF = Dual fuel heat input (total MMBtu/month: diesel + natural gas) EF = HAP-specific emission factor (lbs/MMBtu) 1.70E-03 lb/MMBtu total HAP, 7.89E-05 lb/MMBtu single HAP (diesel) (EQUIs 23-25) 2.28E-02 lb/MMBtu total HAP, 3.24E-03 lb/MMBtu single HAP (natural gas) (EQUIs 23-25) Natural gas units emissions (tons per month) = (NGF*EF*HHVNG)/2000 NGF = Natural gas fuel usage (dscf/month) EF = HAP-specific emission factor (lbs/MMBtu) 7.17E-04 lb/MMBtu total HAP, 4.00E-04 lb/MMBtu single HAP (EQUIs 7, 8) HHVNG = High heating value for natural gas (MMBtu/dscf) Total HAPS (tons per month) are determined by summing all individual (single) HAP (tons per month) emissions. [Minn. R. 7007.0800, subps. 4-5]

Requirement number	Requirement and citation
5.4.7	Emission Factors: Emissions of any HAP calculated with an emission factor on a lb/mmBtu basis shall be calculated by converting fuel usage volume to fuel heat input on a high heating value basis. Approved emission factors are, in order of preference: 1. The emission factor determined during the most recent stack test for this facility and verified by the MPCA in a Notice of Compliance or Notice of Verification, or, 2. The emission factors in EPA's AP-42 chapter 3.1. Any emission factor determination testing shall follow the performance testing requirements in the TFAC 1 subject item in this permit. [Minn. R. 7007.0800, subps. 4-5]
COMG 7	**CO CEMS for EQUI 7 and EQUI 8**
5.5.1	Additional monitoring requirements may apply. The Permittee is responsible for meeting all applicable requirements. [Minn. R. 7007.0800, subp. 4(A)]
5.5.2	Carbon Monoxide: Emissions Monitoring: The Permittee must use a CEMS to measure emissions from EQUI 7 and EQUI 8. [40 CFR pt. 60, subp. GG, Minn. R. 7011.2350, Minn. R. 7017.1010, subp 1]
5.5.3	Continuous Operation: CEMS must be operated and data recorded during all periods of emission unit operation including periods of emission unit start-up, shutdown, or malfunction except for periods of acceptable monitor downtime. This requirement applies whether or not a numerical emission limit applies during these periods. A CEMS must not be bypassed except in emergencies where failure to bypass would endanger human health, safety, or plant equipment. [40 CFR 60.13(e), Minn. R. 7017.1010, subp. 1(A), Minn. R. 7017.1090]
5.5.4	QA Plan: Develop and implement a written quality assurance plan that covers each CEMS. The plan must be on site and available for inspection within 30 days after monitor certification. The plan must contain all of the information required by 40 CFR Part 60, Appendix F, Section 3. The plan must include the manufacturer's spare parts list for each CEMS and require that those parts be kept at the facility unless the Commissioner gives written approval to exclude specific spare parts from the list. [40 CFR pt. 60, Appendix F, 3, Minn. R. 7017.1010, subp. 1(C), Minn. R. 7017.1170, subp. 2]
5.5.5	CEMS QA/QC: The Permittee is subject to the performance specifications listed in 40 CFR pt. 60, Appendix B and shall operate, calibrate, and maintain each CEMS according to the QA/QC procedures in 40 CFR pt. 60, Appendix F as amended and maintain a written QA/QC program available in a form suitable for inspection. [40 CFR 60.13(a), 40 CFR pt. 60, Appendix F, Minn. R. 7017.1010, subp. 1(A)]
5.5.6	CEMS Daily Calibration Drift Test: Check the zero (low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily. The zero and span must, at a minimum, be adjusted whenever the drift exceeds two times the limit specified in 40 CFR pt. 60, Appendix B. 40 CFR pt. 60, Appendix F, Section 4.3.1 must be used to determine out-of-control periods for CEMS. [40 CFR 60.13(d)(1), 40 CFR pt. 60, Appendix F, 4.1, Minn. R. 7017.1010, subp. 1(A), Minn. R. 7017.1170, subp. 3]
5.5.7	Recordkeeping: The Permittee shall retain records of all CEMS monitoring data and support information for a period of five years from the date of the monitoring sample, measurement or report. Records shall be kept at the source. [40 CFR 60.7(f), Minn. R. 7017.1130, Minn. R. 7019.0100, subp. 1]
5.5.8	CEMS Monitor Design: Each CEMS shall be designed to complete a minimum of one cycle of sampling, analyzing, and data recording in each 15-minute period. [40 CFR 60.13(e)(2), Minn. R. 7017.1010, subp. 1(A)]
5.5.9	The Permittee must submit start-up notification: Due 10 working days after Startup of Monitor Date. [Minn. R. 7007.0800, subp. 2(A)]
COMG 8	**Transport Rule/CSAPR for EQUI 1 through 4 and NG CTs EQUI 7 and 8**

Requirement number	Requirement and citation
5.6.1	Transport Rule (TR) NOx Annual Trading Program Requirements. The Permittee shall comply with the TR NOx Annual Trading Program requirements contained in Appendix F. [40 CFR 97.430-435]
5.6.2	Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418. [40 CFR 97.406(a)]
5.6.3	TR NOx Emissions monitoring, reporting, and recordkeeping requirements. 1) The owners and operators and the designated representative of each TR NOx Annual source and each TR NOx Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 40 CFR 97.431 (initial monitoring system certification and recertification procedures), 40 CFR 97.432 (monitoring system out-of-control periods), 40 CFR 97.433 (notifications concerning monitoring), 40 CFR 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 40 CFR 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements). 2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NOx Annual allowances under 40 CFR 97.411(a)(2) and (b) and 40 CFR 97.412 and to determine compliance with the TR NOx Annual emissions limitation and assurance provisions under paragraph 40 CFR 97.406(c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. [40 CFR 97.406(b)]
5.6.4	TR NOx Annual emissions limitation. i) As of the allowance transfer deadline (midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day)) for a control period in a given year, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit at the source shall hold, in the source's compliance account, TR NOx Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Annual units at the source. ii) If total NOx emissions during a control period in a given year from the TR NOx Annual units at a TR NOx Annual source are in excess of the TR NOx Annual emissions limitation set forth in 40 CFR 97.406(c)(1)(i) above, then: A) The owners and operators of the source and each TR NOx Annual unit at the source shall hold the TR NOx Annual allowances required for deduction under 40 CFR 97.424(d); and B) The owners and operators of the source and each TR NOx Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act. [40 CFR 97.406(c)(1)]
5.6.5	TR NOx Annual assurance provisions. i) If total NOx emissions during a control period in a given year from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within the borders of Minnesota exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NOx emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NOx Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by

Requirement number	Requirement and citation
	the Administrator in accordance with 40 CFR 97.425(b), of multiplying- A) The quotient of the amount by which the common designated representative's share of such NOx emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the Minnesota and Indian country within the borders of Minnesota for such control period, by which each common designated representative's share of such NOx emissions exceeds the respective common designated representative's assurance level; and B) The amount by which total NOx emissions from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within the borders of Minnesota for such control period exceed the state assurance level. ii) The owners and operators shall hold the TR NOx Annual allowances required under 40 CFR 97.406(c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period. iii) Total NOx emissions from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within in the borders of Minnesota during a control period in a given year exceed the state assurance level if such total NOx emissions exceed the sum, for such control period, of the state NOx Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b). iv) It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NOx emissions from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within the borders of Minnesota during a control period exceed the state assurance level or if a common designated representative's share of total NOx emissions from the TR NOx Annual units at TR NOx Annual sources in the Minnesota and Indian country within the borders of Minnesota during a control period exceeds the common designated representative's assurance level. v) To the extent the owners and operators fail to hold TR NOx Annual allowances for a control period in a given year in accordance with 40 CFR 97.406(c)(2)(i) through (iii) above, A. The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and B. Each TR NOx Annual allowance that the owners and operators fail to hold for such control period in accordance with 40 CFR 97.406(c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act. [40 CFR 97.406(c)(2)(i)-(v)]
5.6.6	Compliance periods. i) A TR NOx Annual unit shall be subject to the requirements under 40 CFR 97.406(c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter. ii) A TR NOx Annual unit shall be subject to the requirements under 40 CFR 97.406(c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter. [40 CFR 97.406(c)(3)]
5.6.7	Vintage of allowances held for compliance. i) A TR NOx Annual allowance held for compliance with the requirements under 40 CFR 97.406(c)(1)(i) above for a control period in a given year must be a TR NOx Annual allowance that was allocated for such control period or a control period in a prior year. ii) A TR NOx Annual allowance held for compliance with the requirements under 40 CFR 97.406(c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a TR NOx Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year. [40 CFR 97.406(c)(4)]
5.6.8	Allowance Management System requirements. Each TR NOx Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA. [40 CFR 97.406(c)(5)]
5.6.9	Limited authorization.

Requirement number	Requirement and citation
	A TR NOx Annual allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows: i) Such authorization shall only be used in accordance with the TR NOx Annual Trading Program; and ii) Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act. [40 CFR 97.406(c)(6)]
5.6.10	Property right. A TR NOx Annual allowance does not constitute a property right. [40 CFR 97.406(c)(7)]
5.6.11	Additional recordkeeping and reporting requirements. 1) Unless otherwise provided, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator. i) The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each TR NOx Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative. ii) All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA. iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NOx Annual Trading Program. 2) The designated representative of a TR NOx Annual source and each TR NOx Annual unit at the source shall make all submissions required under the TR NOx Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71. [40 CFR 97.406(e)]
5.6.12	Liability. 1) Any provision of the TR NOx Annual Trading Program that applies to a TR NOx Annual source or the designated representative of a TR NOx Annual source shall also apply to the owners and operators of such source and of the TR NOx Annual unit shall also apply to the owners and operators of such unit. 2) Any provision of the TR NOx Annual Trading Program that applies to a TR NOx Annual unit or the designated representative of a TR NOx Annual unit shall also apply to the owners and operators of such unit. [40 CFR 97.406(f)]
5.6.13	Effect on other authorities. No provision of the TR NOx Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NOx Annual source or TR NOx Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act. [40 CFR 97.406(g)]
5.6.14	Transport Rule (TR) SO2 Group 2 Trading Program Requirements. The Permittee shall comply with the TR SO2 Group 2 Trading Program Requirements contained in Appendix F. [40 CFR 97.730-735]
5.6.15	Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.713 through 97.718. [40 CFR 97.706(a)]
5.6.16	TR SO2 Group 2 Emissions monitoring, reporting, and recordkeeping requirements.

Requirement number	Requirement and citation
	1) The owners and operators, and the designated representative, of each TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.730 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 40 CFR 97.731 (initial monitoring system certification and recertification procedures), 40 CFR 97.732 (monitoring system out-of-control periods), 40 CFR 97.733 (notifications concerning monitoring), 40 CFR 97.734 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 40 CFR 97.735 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements). 2) The emissions data determined in accordance with 40 CFR 97.730 through 97.735 shall be used to calculate allocations of TR SO2 Group 2 allowances under 40 CFR 97.711(a)(2) and (b) and 40 CFR 97.712 and to determine compliance with the TR SO2 Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.730 through 97.735 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. [40 CFR 97.706(b)]
5.6.17	TR SO2 Group 2 emissions limitation. i) As of the allowance transfer deadline (midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day)) for a control period in a given year, the owners and operators of each TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall hold, in the source's compliance account, TR SO2 Group 2 allowances available for deduction for such control period under 40 CFR 97.724(a) in an amount not less than the tons of total SO2 emissions for such control period from all TR SO2 Group 2 units at the source. ii) If total SO2 emissions during a control period in a given year from the TR SO2 Group 2 units at a TR SO2 Group 2 source are in excess of the TR SO2 Group 2 emissions limitation set forth in paragraph 40 CFR 97.706(c)(1)(i) above, then: A) The owners and operators of the source and each TR SO2 Group 2 unit at the source shall hold the TR SO2 Group 2 allowances required for deduction under 40 CFR 97.724(d); and B) The owners and operators of the source and each TR SO2 Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart DDDDD and the Clean Air Act. [40 CFR 97.706(c)(1)]
5.6.18	TR SO2 Group 2 assurance provisions. i) If total SO2 emissions during a control period in a given year from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO2 Group 2 allowances available for deduction for such control period under 40 CFR 97.725(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.725(b), of multiplying- A) The quotient of the amount by which the common designated representative's share of such SO2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in Minnesota and Indian country within the borders of Minnesota for such control period, by which each common designated representative's share of such SO2 emissions exceeds the respective common designated representative's assurance level; and B) The amount by which total SO2 emissions from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of

Requirement number	Requirement and citation
	Minnesota for such control period exceed the state assurance level. ii) The owners and operators shall hold the TR SO2 Group 2 allowances required under 40 CFR 97.706(c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period. iii) Total SO2 emissions from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota during a control period in a given year exceed the state assurance level if such total SO2 emissions exceed the sum, for such control period, of the state SO2 Group 2 trading budget under 40 CFR 97.710(a) and the state's variability limit under 40 CFR 97.710(b). iv) It shall not be a violation of 40 CFR part 97, subpart DDDDD or of the Clean Air Act if total SO2 emissions from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota during a control period exceed the state assurance level or if a common designated representative's share of total SO2 emissions from the TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota during a control period exceeds the common designated representative's assurance level. v) To the extent the owners and operators fail to hold TR SO2 Group 2 allowances for a control period in a given year in accordance with 40 CFR 97.706(c)(2)(i) through (iii) above, A.) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and B.) Each TR SO2 Group 2 allowance that the owners and operators fails to hold for such control period in accordance with 40 CFR 97.706(c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart DDDDD and the Clean Air Act. [40 CFR 97.706(c)(2)(i)-(v)]
5.6.19	Compliance Periods. i) A TR SO2 Group 2 unit shall be subject to the requirements under 40 CFR 97.706(c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.730(b) and for each control period thereafter ii) A TR SO2 Group 2 unit shall be subject to the requirements under 40 CFR 97.706(c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.730(b) and for each control period thereafter. [40 CFR 97.706(c)(3)]
5.6.20	Vintage of allowances held for compliance. i) A TR SO2 Group 2 allowance held for compliance with the requirements under 40 CFR 97.706(c)(1)(i) above for a control period in a given year must be a TR SO2 Group 2 allowance that was allocated for such control period or a control period in a prior year. ii) A TR SO2 Group 2 allowance held for compliance with the requirements under 40 CFR 97.706(c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a TR SO2 Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year. [40 CFR 97.706(c)(4)]
5.6.21	Allowance Management System requirements. Each TR SO2 Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart DDDDD. [40 CFR 97.706(c)(5)]
5.6.22	Limited authorization. A TR SO2 Group 2 allowance is a limited authorization to emit one ton of SO2 during the control period in one year. Such authorization is limited in its use and duration as follows: i) Such authorization shall only be used in accordance with the TR SO2 Group 2 Trading Program; and ii) Notwithstanding any other provision of 40 CFR part 97, subpart DDDDD, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act. [40 CFR 97.706(c)(6)]

Requirement number	Requirement and citation
5.6.23	Property right. A TR SO2 Group 2 allowance does not constitute a property right. [40 CFR 97.706(c)(7)]
5.6.24	Additional recordkeeping and reporting requirements. 1) Unless otherwise provided, the owners and operators of each TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator. i) The certificate of representation under 40 CFR 97.716 for the designated representative for the source and each TR SO2 Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.716 changing the designated representative. ii) All emissions monitoring information, in accordance with 40 CFR part 97, subpart DDDDD. iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO2 Group 2 Trading Program. 2) The designated representative of a TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall make all submissions required under the TR SO2 Group 2 Trading Program, except as provided in 40 CFR 97.718. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71. [40 CFR 97.706(e)]
5.6.25	Liability. 1) Any provision of the TR SO2 Group 2 Trading Program that applies to a TR SO2 Group 2 source or the designated representative of a TR SO2 Group 2 source shall also apply to the owners and operators of such source and of the TR SO2 Group 2 units at the source. 2) Any provision of the TR SO2 Group 2 Trading Program that applies to a TR SO2 Group 2 unit or the designated representative of a TR SO2 Group 2 unit shall also apply to the owners and operators of such unit. [40 CFR 97.706(f)]
5.6.26	Effect on other authorities. No provision of the TR SO2 Group 2 Trading Program or exemption under 40 CFR 97.705 shall be construed as exempting or excluding the owners or operators, and the designated representative, of a TR SO2 Group 2 source or TR SO2 Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act. [40 CFR 97.706(g)]
COMG 9	**O2 CEMS for EQUI 7 and EQUI 8**
5.7.1	Additional monitoring requirements may apply. The Permittee is responsible for meeting all applicable requirements. [Minn. R. 7007.0800, subp. 4(A)]
5.7.2	Emissions Monitoring: The owner or operator shall use a CEMS to measure emissions from EQUI 7 and EQUI 8. [40 CFR 75.10(a)]
5.7.3	Monitoring Data: Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data is unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to 40 CFR 75.21 and appendix B of 40 CFR pt. 75, or backups of data from the data acquisition and handling system, or recertification, pursuant to 40 CFR 75.20. The Permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent

Requirement number	Requirement and citation
	practicable, evenly spaced over the hour. [40 CFR 75.10(d)(1)]
5.7.4	CEMS QA/QC: The owner or operator of an affected facility shall operate, calibrate, and maintain each CEMS according to the QA/QC procedures in 40 CFR pt. 75, Appendix B as amended. [40 CFR 75.21(a)]
5.7.5	Quarterly Reports: Electronically report the data and information in 40 CFR 75.64(a), (b), and (c) to the Administrator quarterly. [40 CFR 75.64]
5.7.6	Recordkeeping: The Permittee shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. The file shall contain all information required by 40 CFR 75.57. [40 CFR 75.57]
5.7.7	Daily Calibration error (CE) Test: conduct daily CE testing on all CEMS required by the Acid Rain Program, in accordance with 40 CFR pt. 75, appendix B. [40 CFR pt. 75, Appendix B(Sect 2.1)]
EQUI 1	**Combustion Turbine 1 (50 MW) - Turbine**
5.8.1	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 1. [Minn. R. 7007.0800, subp. 2(A)]
5.8.2	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.8.3	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.8.4	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
5.8.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.8.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]
EQUI 2	**Combustion Turbine 2 (50 MW) - Turbine**
5.9.1	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 2. [Minn. R. 7007.0800, subp. 2(A)]
5.9.2	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.9.3	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.9.4	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
5.9.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.9.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]

Requirement number	Requirement and citation
EQUI 3	**Combustion Turbine 3 (50 MW) - Turbine**
5.10.1	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 3. [Minn. R. 7007.0800, subp. 2(A)]
5.10.2	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.10.3	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.10.4	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
5.10.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.10.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]
EQUI 4	**Combustion Turbine 4 (55 MW) - Turbine**
5.11.1	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 4. [Minn. R. 7007.0800, subp. 2(A)]
5.11.2	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.11.3	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.11.4	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
5.11.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.11.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]
EQUI 5	**Emergency Engine/Generator**
5.12.1	The Permittee is subject to pt. 63, subp. ZZZZ because it owns and operates EQUI 5 (a stationary RICE) located at an area HAP emissions source, and EQUI 5 is not being tested at a stationary RICE test cell/stand. [40 CFR 63.6585, Minn. R. 7011.8150]
5.12.2	EQUI 5 is an existing 175 hp compression ignition stationary RICE installed in 1993 subject to 40 CFR pt. 63, subp. ZZZZ because it has a site rating of equal to or less than 500 brake HP, is located at an area HAP emissions source, and the Permittee commenced construction of EQUI 5 before June 12, 2006. [40 CFR 63.6590(a)(1)(iii), Minn. R. 7011.8150]
5.12.3	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.12.4	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is

Requirement number	Requirement and citation
	0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.12.5	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
5.12.6	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, limiting operation to 500 hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.12.7	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
5.12.8	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5]
5.12.9	The Permittee must comply with all applicable requirements of 40 CFR pt. 63, subp. ZZZZ as follows: 40 CFR 63.6585(a), 40 CFR 63.6585(c), 40 CFR 63.6585(d), 40 CFR 63.6590 (a)(1)(iii), 40 CFR 63.6595(a), 40 CFR 63.6603(a), 40 CFR 63.6605(a), 40 CFR 63.6605(b), 40 CFR 63.6625 (e)(3), 40 CFR 63.6625(f), 40 CFR 63.6625(h), 40 CFR 63.6625(i), 40 CFR 63.6640(a), 40 CFR 63.6640(b), 40 CFR 63.6640 (e), 40 CFR 63.6640(f), 40 CFR 63.6640(f)(1), 40 CFR 63.6640(f)(2)(i), 40 CFR 63.6640(f)(4), 40 CFR 63.6650(f), 40 CFR 63.6655(a)(1)-(2), 40 CFR 63.6655(e), 40 CFR 63.6655(f), 40 CFR 63.6660, 40 CFR 63.6665, 40 CFR 63.6675, 40 CFR pt. 63, subp ZZZZ Table 2(d)(Item 4), 40 CFR pt. 63, subp ZZZZ Table 6 (item 9), 40 CFR pt. 63, subp ZZZZ Table 8. A copy of 40 CFR pt. 63, subp. ZZZZ is included in Appendix E. If the applicable sections of the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 63, subp. ZZZZ, Minn. R.

Requirement number	Requirement and citation
	7011.8150]
5.12.10	The Permittee must comply with all applicable requirements of 40 CFR pt. 63, subp. A as follows: 40 CFR 63.1(a); 40 CFR 63.1(b)(1); 40 CFR 63.1(b)(3); 40 CFR 63.1(c)(1); 40 CFR 63.1(c)(2); 40 CFR 63.1(c)(5); 40 CFR 63.1(e); 40 CFR 63.2; 40 CFR 63.3; 40 CFR 63.4; 40 CFR 63.5(a); 40 CFR 63.5(b); 40 CFR 63.5(d); 40 CFR 63.5(e); 40 CFR 63.5(f); 40 CFR 63.6(a)(1); 40 CFR 63.6(a)(2); 40 CFR 63.6(c)(1); 40 CFR 63.6(c)(2); 40 CFR 63.6(c)(5); 40 CFR 63.6(i)(1); 40 CFR 63.6(i)(2); 40 CFR 63.6(i)(3); 40 CFR 63.6(i)(4); 40 CFR 63.6(i)(6); 40 CFR 63.6(i)(8); 40 CFR 63.6(i)(9); 40 CFR 63.6(i)(11); 40 CFR 63.6(j); 40 CFR 63.7(a)(2); 40 CFR 63.7(a)(2)(ix); 40 CFR 63.7(a)(3); 40 CFR 63.7(a)(4); 40 CFR 63.7(b); 40 CFR 63.7(c); 40 CFR 63.7(d); 40 CFR 63.7(f); 40 CFR 63.7(g); 40 CFR 63.7(h); 40 CFR 63.8(b)(1); 40 CFR 63.8(g); 40 CFR 63.9(b)(1); 40 CFR 63.9(b)(2); 40 CFR 63.9(b)(4); 40 CFR 63.9(c); 40 CFR 63.9(e); 40 CFR 63.9(h); 40 CFR 63.9(i); 40 CFR 63.9(j);

Requirement number	Requirement and citation
	40 CFR 63.10(a)(5); 40 CFR 63.10(a)(6); 40 CFR 63.10(a)(7); 40 CFR 63.10(b)(1); 40 CFR 63.10(b)(2)(ix); 40 CFR 63.10(b)(2)(xii); 40 CFR 63.10(b)(2)(xiii); 40 CFR 63.10(b)(2)(xiv); 40 CFR 63.10(b)(3); 40 CFR 63.10(d)(1); 40 CFR 63.10(d)(2); 40 CFR 63.10(d)(4); 40 CFR 63.10(f); 40 CFR 63.12; 40 CFR 63.13; 40 CFR 63.14; 40 CFR 63.15(a); 40 CFR 63.15(b). A copy of 40 CFR pt. 63, subp. A is included in Appendix D. If the applicable sections of the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 63, subp. A, 40 CFR pt. 63, subp. ZZZZ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.7000, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.12.11	Temporary replacement conditions: The Permittee may temporarily replace this unit (EQUI 5), provided the following conditions are met: 1) The potential emissions of the replacement unit (including the effect of all enforceable limits imposed through this permit) are less than all of the following: 25 tpy PM, 15 tpy PM < 10 microns, 10 tpy PM < 2.5 microns, 40 tpy VOC, 40 tpy SO2, 40 tpy NOx, 100 tpy CO, 75000 tpy CO2e; 2) For pollutants not specifically limited by a permit or rule, the Permittee shall calculate emissions using an emission factor provided by the temporary replacement engine manufacturer if available, or from AP-42 if not available; 3) The heat input capacity of the replacement unit is less than or equal to the unit it replaces; 4) The project can only be the temporary replacement of an internal combustion engine(s) for the purpose of providing emergency electrical power at the facility; 5) Emissions and operating hours are tracked and calculated as specified in this permit; 6) The replacement engine may only replace a permanent engine that is temporarily out of service for less than one year; 7) The replacement engine must meet the conditions for temporary replacement units under 40 CFR Section 60.4200(e); 8) Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment. The Permittee is not required to complete emission calculations described in Minn. R. 7007.1200 subp. 2. A permit will still be needed regardless of the emissions increase if the change will be subject to a new applicable requirement or requires revisions to the limits or monitoring and recordkeeping in this permit. [40 CFR 60.4200(e), Minn. R. 7005.0100, subp. 35a, Minn. R. 7007.0800, Minn. R. 7007.1200, subp. 3, Minn. R. 7011.2305, Title I Condition: Avoid major modification under 40 CFR 52.21(b)(2) and Minn. R. 7007.3000]
5.12.12	If installation of the temporary replacement engine does not require a permit amendment, the Permittee shall keep the following records on site for each replacement engine not requiring a permit

Requirement number	Requirement and citation
	amendment: - Records required by Minn. R. 7007.1200, subp. 4; - The dates the temporary engine was installed, started operation, and was removed; - Filled form GI05B for each replacement engine with an assigned consecutive emission unit number; - A unique identification for the unit, such as make, model, and serial number; - Rated capacity and type of engine; - Dates and hours of operation of the engine; - A statement of all periods of operation during which the permanent engine being temporarily replaced is not also operating; and - Calculations of the potential to emit of the engine and emission changes pursuant to Minn. R. 7007.1200 subpart 3. [Minn. R. 7007.0800, subp. 5, Minn. R. 7007.1200, subp. 4, Title I Condition: Avoid major modification under 40 CFR 52.21(b)(2) and Minn. R. 7007.3000]
5.12.13	The Permittee shall notify the MPCA if the replacement engine is operated simultaneously with the permanent engine being temporarily replaced, except as allowed by this permit. Make verbal notification within 2 days, and written notification with the semi-annual deviations report. [Minn. R. 7007.0800, subp. 5, Minn. R. 7007.1200, subp. 4]
EQUI 7	**GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)**
5.13.1	EQUI 7 is subject to the U.S. EPA Acid Rain Program codified at 40 CFR Parts 72 and 75. EQUI 7 meets the definitions of utility unit, new unit, and gas-fired unit, as defined in 40 CFR 72.2. Some of the Acid Rain Program requirements are included in this permit for MPCA tracking purposes. The Permittee submitted a copy of their Acid Rain Permit Application with the reissuance application submitted on 03/22/2019. The Acid Rain Permit Application can be found in Appendix B of this permit. [40 CFR pt. 72]
5.13.2	If EQUI 7 has excess emissions as defined in STEP 3 of the Acid Rain Permit Application found in Appendix B of this permit, the designated representative shall submit a proposed offset plan in accordance with 40 CFR 72.9(e). [40 CFR 72.9(e), Minn. R. 7007.1075]
5.13.3	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and continues until Mode 6 is attained. 2. Shutdown begins when the shutdown sequence is initiated and the unit leaves Mode 6. 3. Emergency operation occurs when the unit is not in Mode 6 but shutdown has not been initiated. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.4	The Permittee must limit emissions of Particulate Matter <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.5	The Permittee must limit emissions of Particulate Matter <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.6	The Permittee must limit emissions of PM < 10 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.7	The Permittee must limit emissions of PM < 10 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.8	The Permittee must limit emissions of PM < 2.5 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.9	The Permittee must limit emissions of PM < 2.5 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.13.10	The Permittee must limit emissions of Nitrogen Oxides <= 11 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
5.13.11	The Permittee must limit emissions of Nitrogen Oxides <= 73.51 pounds per hour 24-hour rolling average. This limit applies during normal operation. Normal operation commences upon initial attainment of Mode 6 operation. Mode 6 operation occurs when all burner nozzles are firing in low-NOx configuration. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.13.12	The Permittee must limit emissions of Nitrogen Oxides <= 6.76 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 68 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.13	The Permittee must limit emissions of Nitrogen Oxides <= 7.29 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 304 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.14	The Permittee must limit emissions of Nitrogen Oxides <= 110 parts per million 3-hour average by volume on a dry basis corrected to 15 percent oxygen. This limit applies at all times except during startup, shutdown or malfunction. [40 CFR 60.332, Minn. R. 7011.2350]
5.13.15	The Permittee must limit emissions of Carbon Monoxide <= 9 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.16	The Permittee must limit emissions of Carbon Monoxide <= 38.80 pounds per hour 24-hour rolling average. This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.17	The Permittee must limit emissions of Carbon Monoxide <= 18.01 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 180 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.18	The Permittee must limit emissions of Carbon Monoxide <= 11.47 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 478 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.19	The Permittee must limit emissions of Volatile Organic Compounds <= 4.6 parts per million 3-hour block average (dry basis) at actual O2 (as methane). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.20	The Permittee must limit emissions of Volatile Organic Compounds <= 10.03 pounds per hour 3-hour average (as methane). This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.21	The Permittee must limit emissions of Volatile Organic Compounds <= 8.64 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 86 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.22	The Permittee must limit emissions of Volatile Organic Compounds <= 24.95 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 1040 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.23	The Permittee must limit emissions of Sulfur Dioxide <= 0.015 percent by volume at 15 percent oxygen and on a dry basis, or Sulfur Content of Fuel: less than or equal to 0.8 percent by weight. [40 CFR 60.333, Minn. R. 7011.2350]
5.13.24	The Permittee must limit emissions of Carbon Dioxide <= 110 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.25	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 986,539 tons per year 12-month

Requirement number	Requirement and citation
	rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.26	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.13.27	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.13.28	Fuel type: Pipeline natural gas, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.29	Daily Recordkeeping. On each day of operation, the Permittee shall calculate and record the total EQUI 7 fuel usage. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subp. 5]
5.13.30	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.31	CO Monitoring: The Permittee shall monitor CO emissions on both a lb/mmBtu and a lb/hr basis using any of the following methods: 1. A CO CEMS on EQUI 7 stack/vent (STRU 12) to monitor CO emissions as described by this permit. [Minn. R. 7007.0800, subps. 4-5]
5.13.32	SO2 Emissions Monitoring: The Permittee shall monitor SO2 according to 40 CFR Part 75 Appendix D Sections 2.1, 2.3, 2.4, 3.3, 3.4, and 3.5. The Permittee shall use the hourly SO2 emissions calculated according to 40 CFR Part 75 Appendix D, Section 3.3 to determine daily, monthly, and 12-month rolling sum (ton per year) EQUI 7 SO2 emissions. If the Permittee becomes eligible, the Permittee may use the low mass emission (LME) excepted methodology described in 40 CFR 75.19(c)(1)(ii) to determine SO2 emissions. Since the Permittee elected not to install a SO2 CEMS, the Permittee shall determine SO2 emissions in lb/mmBtu, according to 40 CFR Part 75 Appendix D - Optional SO2 emissions Data Protocol For Gas-fired and Oil-fired Units, or, if eligible, according to 40 CFR 75.19(c)(1)(ii). [40 CFR pt. 75, Appendix D, Minn. R. 7007.0800, subps. 4-5]
5.13.33	The Permittee is not required to use Continuous Emission Monitoring Systems (CEMS) for sulfur dioxide provided the Permittee complies with the requirements of 40 CFR Part 75 Appendix D or 40 CFR 75.19(c)(1)(ii). [40 CFR 75.10(a)(1), 40 CFR 75.11(d)(2) and (3)]
5.13.34	Fuel Monitoring: The Permittee shall follow the applicable fuel sulfur and nitrogen content monitoring requirements in 40 CFR 60.334(h) and monitor at the frequency specified in 40 CFR 60.334(i). [40 CFR 60.334(h) and (i), Minn. R. 7007.0800, subp. 4, Minn. R. 7011.2350]
5.13.35	Monthly Recordkeeping. CO Emissions: By the 15th of the month, the Permittee shall calculate and record the EQUI 7 CO emissions for the previous calendar month (in tons per month) using one of the following methods: 1. A CO CEMS to determine hourly CO lb/hr emissions for each hour of operation; or 2. Hourly CO lb/hr emissions data for each hour of operation based on fuel usage and the appropriate AP-42 emission factor and hourly heat input. 3. Approved emission factors for calculating CO emissions are the CO factor in EPA's AP-42 chapter 3.1, Table 3.1-1 for Natural Gas-Fired lean-premix turbines. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subps. 4-5]
5.13.36	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 7. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation:

Requirement number	Requirement and citation
	GHG = ((MNG * 110) + ((MNG * 0.0086) * 25) + ((MNG * 0.00022) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0086 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 7 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.37	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 200 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.38	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 7 while operating in emergency mode. Sum the number of hours EQUI 7 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.39	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.40	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.41	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.13.42	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1(a); 40 CFR 60.1(b); 40 CFR 60.1(c); 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5(a); 40 CFR 60.5(b); 40 CFR 60.6(a); 40 CFR 60.6(b); 40 CFR 60.7(a)(1); 40 CFR 60.7(a)(3); 40 CFR 60.7(a)(4);

Requirement number	Requirement and citation
	40 CFR 60.7(a)(5);
	40 CFR 60.7(b);
	40 CFR 60.7(c);
	40 CFR 60.7(d);
	40 CFR 60.8(a);
	40 CFR 60.8(b);
	40 CFR 60.8(c);
	40 CFR 60.8(d);
	40 CFR 60.8(e);
	40 CFR 60.8(f);
	40 CFR 60.8(g);
	40 CFR 60.8(h);
	40 CFR 60.8(i);
	40 CFR 60.9;
	40 CFR 60.11(a);
	40 CFR 60.11(d);
	40 CFR 60.11(f);
	40 CFR 60.11(g);
	40 CFR 60.12;
	40 CFR 60.13(a);
	40 CFR 60.13(b);
	40 CFR 60.13(c);
	40 CFR 60.13(d)(1);
	40 CFR 60.13(e)(2);
	40 CFR 60.13(f);
	40 CFR 60.13(g);
	40 CFR 60.13(h)(2);
	40 CFR 60.13(h)(3);
	40 CFR 60.13(i)(1);
	40 CFR 60.13(i)(2);
	40 CFR 60.13(i)(3);
	40 CFR 60.13(i)(4);
	40 CFR 60.13(i)(5);
	40 CFR 60.13(i)(6);
	40 CFR 60.13(i)(7);
	40 CFR 60.13(i)(8);
	40 CFR 60.13(i)(9);
	40 CFR 60.13(j)(1);
	40 CFR 60.13(j)(2);
	40 CFR 60.14(a);
	40 CFR 60.14(b);
	40 CFR 60.14(c);
	40 CFR 60.14(e);
	40 CFR 60.14(f);
	40 CFR 60.14(g);
	40 CFR 60.14(h);
	40 CFR 60.14(i);
	40 CFR 60.14(j);
	40 CFR 60.15(a);
	40 CFR 60.15(b);
	40 CFR 60.15(c);
	40 CFR 60.15(d);

Requirement number	Requirement and citation
	40 CFR 60.15(e); 40 CFR 60.15(f); 40 CFR 60.15(g); 40 CFR 60.17; 40 CFR 60.19(a); 40 CFR 60.19(b); 40 CFR 60.19(c); 40 CFR 60.19(d); 40 CFR 60.19(e); 40 CFR 60.19(f)(1); 40 CFR 60.19(f)(2); 40 CFR 60.19(f)(3); and 40 CFR 60.19(f)(4). A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the applicable sections of the standard change or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. GG, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2350, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 8	**GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)**
5.14.1	EQUI 8 is subject to the U.S. EPA Acid Rain Program codified at 40 CFR Parts 72 and 75. EQUI 8 meets the definitions of utility unit, new unit, and gas-fired unit, as defined in 40 CFR 72.2. Some of the Acid Rain Program requirements are included in this permit for MPCA tracking purposes. The Permittee submitted a copy of their Acid Rain Permit Application with the reissuance application submitted on 03/22/2019. The Acid Rain Permit Application can be found in Appendix B of this permit. [40 CFR pt. 72]
5.14.2	If EQUI 8 has excess emissions as defined in STEP 3 of the Acid Rain Permit Application found in Appendix B of this permit, the designated representative shall submit a proposed offset plan in accordance with 40 CFR 72.9(e). [40 CFR 72.9(e), Minn. R. 7007.1075]
5.14.3	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and continues until Mode 6 is attained. 2. Shutdown begins when the shutdown sequence is initiated and the unit leaves Mode 6. 3. Emergency operation occurs when the unit is not in Mode 6 but shutdown has not been initiated. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.4	The Permittee must limit emissions of Particulate Matter <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.5	The Permittee must limit emissions of Particulate Matter <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.6	The Permittee must limit emissions of PM < 10 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.7	The Permittee must limit emissions of PM < 10 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.8	The Permittee must limit emissions of PM < 2.5 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.9	The Permittee must limit emissions of PM < 2.5 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR

Requirement number	Requirement and citation
	52.21(k)(modeling) and Minn. R. 7007.3000]
5.14.10	The Permittee must limit emissions of Nitrogen Oxides <= 11 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.11	The Permittee must limit emissions of Nitrogen Oxides <= 73.51 pounds per hour 24-hour rolling average. This limit applies during normal operation. Normal operation commences upon initial attainment of Mode 6 operation. Mode 6 operation occurs when all burner nozzles are firing in low-NOx configuration. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.14.12	The Permittee must limit emissions of Nitrogen Oxides <= 6.76 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 68 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.13	The Permittee must limit emissions of Nitrogen Oxides <= 7.29 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 304 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.14	The Permittee must limit emissions of Nitrogen Oxides <= 110 parts per million 3-hour average by volume on a dry basis corrected to 15 percent oxygen. This limit applies at all times except during startup, shutdown or malfunction. [40 CFR 60.332, Minn. R. 7011.2350]
5.14.15	The Permittee must limit emissions of Carbon Monoxide <= 9 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.16	The Permittee must limit emissions of Carbon Monoxide <= 38.80 pounds per hour 24-hour rolling average. This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.17	The Permittee must limit emissions of Carbon Monoxide <= 18.01 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 180 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.18	The Permittee must limit emissions of Carbon Monoxide <= 11.47 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 478 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.19	The Permittee must limit emissions of Volatile Organic Compounds <= 4.6 parts per million 3-hour block average (dry basis) at actual O2 (as methane). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.20	The Permittee must limit emissions of Volatile Organic Compounds <= 10.03 pounds per hour 3-hour average (as methane). This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.21	The Permittee must limit emissions of Volatile Organic Compounds <= 8.64 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 86 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.22	The Permittee must limit emissions of Volatile Organic Compounds <= 24.95 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 1040 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.23	The Permittee must limit emissions of Sulfur Dioxide <= 0.015 percent by volume at 15 percent oxygen and on a dry basis, or Sulfur Content of Fuel: less than or equal to 0.8 percent by weight. [40 CFR 60.333, Minn. R.

Requirement number	Requirement and citation
	7011.2350]
5.14.24	The Permittee must limit emissions of Carbon Dioxide <= 110 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.25	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 986,539 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.26	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.14.27	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.14.28	Fuel type: Pipeline natural gas, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.29	Daily Recordkeeping. On each day of operation, the Permittee shall calculate and record the total EQUI 8 fuel usage. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subp. 5]
5.14.30	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.31	CO Monitoring: The Permittee shall monitor CO emissions on both a lb/mmBtu and a lb/hr basis using any of the following methods: 1. A CO CEMS on EQUI 8 stack/vent (STRU 13) to monitor CO emissions as described by this permit. [Minn. R. 7007.0800, subps. 4-5]
5.14.32	SO2 Emissions Monitoring: The Permittee shall monitor SO2 according to 40 CFR Part 75 Appendix D Sections 2.1, 2.3, 2.4, 3.3, 3.4, and 3.5. The Permittee shall use the hourly SO2 emissions calculated according to 40 CFR Part 75 Appendix D, Section 3.3 to determine daily, monthly, and 12-month rolling sum (ton per year) EQUI 8 SO2 emissions. If the Permittee becomes eligible, the Permittee may use the low mass emission (LME) excepted methodology described in 40 CFR 75.19(c)(1)(ii) to determine SO2 emissions. Since the Permittee elected not to install a SO2 CEMS, the Permittee shall determine SO2 emissions in lb/mmBtu, according to 40 CFR Part 75 Appendix D - Optional SO2 emissions Data Protocol For Gas-fired and Oil-fired Units, or, if eligible, according to 40 CFR 75.19(c)(1)(ii). [40 CFR pt. 75, Appendix D, Minn. R. 7007.0800, subps. 4-5]
5.14.33	The Permittee is not required to use Continuous Emission Monitoring Systems (CEMS) for sulfur dioxide provided the Permittee complies with the requirements of 40 CFR Part 75 Appendix D or 40 CFR 75.19(c)(1)(ii). [40 CFR 75.10(a)(1), 40 CFR 75.11(d)(2) and (3)]
5.14.34	Fuel Monitoring: The Permittee shall follow the applicable fuel sulfur and nitrogen content monitoring requirements in 40 CFR 60.334(h) and monitor at the frequency specified in 40 CFR 60.334(i). [40 CFR 60.334(h) and (i), Minn. R. 7007.0800, subp. 4, Minn. R. 7011.2350]
5.14.35	Monthly Recordkeeping. CO Emissions: By the 15th of the month, the Permittee shall calculate and record the EQUI 8 CO emissions for the previous calendar month (in tons per month) using one of the following methods: 1. A CO CEMS to determine hourly CO lb/hr emissions for each hour of operation; or, 2. Hourly CO lb/hr emissions data for each hour of operation based on fuel usage and the appropriate AP-42 emission factor and hourly heat input. 3. Approved emission factors for calculating CO emissions are the CO factor in EPA's AP-42 chapter 3.1, Table 3.1-1 for Natural Gas-Fired lean-premix turbines. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subps. 4-5]

Requirement number	Requirement and citation
5.14.36	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 8. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MNG * 110) + ((MNG * 0.0086) * 25) + ((MNG * 0.00022) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0086 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 8 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.37	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 200 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.38	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 8 while operating in emergency mode. Sum the number of hours EQUI 8 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.39	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.40	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.41	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.14.42	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1(a); 40 CFR 60.1(b); 40 CFR 60.1(c); 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5(a); 40 CFR 60.5(b); 40 CFR 60.6(a);

Requirement number	Requirement and citation
	40 CFR 60.6(b);
	40 CFR 60.7(a)(1);
	40 CFR 60.7(a)(3);
	40 CFR 60.7(a)(4);
	40 CFR 60.7(a)(5);
	40 CFR 60.7(b);
	40 CFR 60.7(c);
	40 CFR 60.7(d);
	40 CFR 60.8(a);
	40 CFR 60.8(b);
	40 CFR 60.8(c);
	40 CFR 60.8(d);
	40 CFR 60.8(e);
	40 CFR 60.8(f);
	40 CFR 60.8(g);
	40 CFR 60.8(h);
	40 CFR 60.8(i);
	40 CFR 60.9;
	40 CFR 60.11(a);
	40 CFR 60.11(d);
	40 CFR 60.11(f);
	40 CFR 60.11(g);
	40 CFR 60.12;
	40 CFR 60.13(a);
	40 CFR 60.13(b);
	40 CFR 60.13(c);
	40 CFR 60.13(d)(1);
	40 CFR 60.13(e)(2);
	40 CFR 60.13(f);
	40 CFR 60.13(g);
	40 CFR 60.13(h)(2);
	40 CFR 60.13(h)(3);
	40 CFR 60.13(i)(1);
	40 CFR 60.13(i)(2);
	40 CFR 60.13(i)(3);
	40 CFR 60.13(i)(4);
	40 CFR 60.13(i)(5);
	40 CFR 60.13(i)(6);
	40 CFR 60.13(i)(7);
	40 CFR 60.13(i)(8);
	40 CFR 60.13(i)(9);
	40 CFR 60.13(j)(1);
	40 CFR 60.13(j)(2);
	40 CFR 60.14(a);
	40 CFR 60.14(b);
	40 CFR 60.14(c);
	40 CFR 60.14(e);
	40 CFR 60.14(f);
	40 CFR 60.14(g);
	40 CFR 60.14(h);
	40 CFR 60.14(i);
	40 CFR 60.14(j);

Requirement number	Requirement and citation
	40 CFR 60.15(a); 40 CFR 60.15(b); 40 CFR 60.15(c); 40 CFR 60.15(d); 40 CFR 60.15(e); 40 CFR 60.15(f); 40 CFR 60.15(g); 40 CFR 60.17; 40 CFR 60.19(a); 40 CFR 60.19(b); 40 CFR 60.19(c); 40 CFR 60.19(d); 40 CFR 60.19(e); 40 CFR 60.19(f)(1); 40 CFR 60.19(f)(2); 40 CFR 60.19(f)(3); and 40 CFR 60.19(f)(4). A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If applicable sections of the standard change or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. GG, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2350, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 23	**Engine Generator 1**
5.15.1	Alternative Operating Scenario 1 (AOS 1): Engine Generator 1 (EQUI 23) operates while firing natural gas with ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
5.15.2	Alternative Operating Scenario 2 (AOS 2): Engine Generator 1 (EQUI 23) operates while firing ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
5.15.3	Recordkeeping of Alternative Operating Scenario: On each day of operation, the Permittee shall record the alternative operating scenario in which the engine generator is operating. If the Permittee changes the alternative operating scenario, record the date and time of the change and the new alternative operating scenario in which the engine generator is operating. [Minn. R. 7007.0800, subp. 11, Minn. R. 7007.0800, subps. 4-5]
5.15.4	The Permittee must limit Operating Hours <= 241 hours per year 12-month rolling sum in burn-in operation during the 12-month period following initial startup of EQUI 23. This limit expires 366 days after initial startup of EQUI 23. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.5	The Permittee must limit Operating Hours <= 8109 hours per year 12-month rolling sum in normal operation during the 12-month period following initial startup of EQUI 23. This limit expires 366 days after initial startup of EQUI 23. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.6	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 23 operated in burn-in operation. The Permittee shall record the start time and stop time in burn-in operation. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.7	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 23 operated in normal operation. The Permittee shall record the start time and stop time in normal operation. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and

Requirement number	Requirement and citation
	Minn. R. 7007.3000]
5.15.8	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 23 in burn-in operation for the previous month, and 2. the total hours of EQUI 23 in burn-in operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5]
5.15.9	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 23 in normal operation for the previous month, and 2. the total hours of EQUI 23 in normal operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5]
5.15.10	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and until 75% load is attained. 2. Shutdown begins when the fuel feed is ceased. 3. Emergency operation occurs when the unit is at less than 75% load and not in startup. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.11	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.15.12	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.15.13	Fuel type: Natural gas and Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.14	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.15	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.16	EQUI 23 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subps. IIII and JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 23. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.15.17	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; 40 CFR 60.15;

Requirement number	Requirement and citation
	40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.15.18	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a); 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4204(c)(3); 40 CFR 60.4204(c)(4); 40 CFR 60.4206; 40 CFR 60.4207(d); 40 CFR 60.4211(a)(1)-(a)(3); 40 CFR 60.4211(d)(1)-(d)(3); 40 CFR 60.4213(a)-(f); 40 CFR 60.4214(a)(1)-(a)(2); 40 CFR 60.4218; 40 CFR 60.4219; 40 CFR pt. 60, subp. IIII Table 7 items (b)-(d); and 40 CFR pt. 60, subp. IIII Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.15.19	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15;

Requirement number	Requirement and citation
	40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJJ(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.15.20	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows: 40 CFR 60.4230(a)(6); 40 CFR 60.4233(e); 40 CFR 60.4234; 40 CFR 60.4236(b); 40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4243(e); 40 CFR 60.4244; 40 CFR 60.4245(a)(1), (a)(2), and (a)(4); 40 CFR 60.4245(c); 40 CFR 60.4245(d); 40 CFR 60.4246(a); 40 CFR 60.4246(b); 40 CFR 60.4248; 40 CFR pt. 60, subp. JJJJ Table 1; 40 CFR pt. 60, subp. JJJJ Table 2; 40 CFR pt. 60, subp. JJJJ Table 3; and 40 CFR pt. 60, subp. JJJJ Table 4. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix K. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.15.21	The Permittee must limit emissions of Nitrogen Oxides according to the following equation in units of grams per horsepower-hour: NOx <= 6.7 * n^-0.20 or in units of grams per kilowatt-hour: NOx <= 9.0 * n^-0.20 Where: NOx = nitrogen oxide emissions, g/hp-hr or g/kW-hr n = maximum engine speed >= 130 rpm and < 2000 rpm This limit applies when operating in AOS 2. [40 CFR 60.4204(c)(3)(ii), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]

Requirement number	Requirement and citation
5.15.22	The Permittee must limit emissions of Nitrogen Oxides <= 1.0 grams per horsepower-hour (1.36 g/kW-hr) or 82 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.15.23	The Permittee must limit emissions of Carbon Monoxide <= 2.0 grams per horsepower-hour (2.72 g/kW-hr) or 270 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.15.24	The Permittee must limit emissions of Volatile Organic Compounds <= 0.7 grams per horsepower-hour (0.95 g/kW-hr) or 60 ppmvd at 15% O2, not including formaldehyde, when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.15.25	The Permittee must limit emissions of Nitrogen Oxides <= 0.07 grams per horsepower-hour 24-hour rolling average (0.09 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.26	The Permittee must limit emissions of Nitrogen Oxides <= 0.39 grams per horsepower-hour 24-hour rolling average (0.53 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.27	The Permittee must limit emissions of Nitrogen Oxides <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.28	The Permittee must limit emissions of Nitrogen Oxides <= 0.49 grams per horsepower-hour 24-hour rolling average (0.66 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.29	The Permittee must limit emissions of Nitrogen Oxides <= 1.65 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.30	The Permittee must limit emissions of Nitrogen Oxides <= 10.86 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.15.31	The Permittee must limit emissions of Nitrogen Oxides <= 15.82 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 45.20 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.32	The Permittee must limit emissions of Nitrogen Oxides <= 2.16 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 90 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.33	The Permittee must limit emissions of Particulate Matter <= 0.11 grams per horsepower-hour 24-hour

Requirement number	Requirement and citation
	rolling average (0.15 g/kW-hr), or reduce particulate matter emissions by 60% or more. This limit applies when operating in AOS 2 at greater than or equal to 75% load. [40 CFR 60.4204(c)(4), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.34	The Permittee must limit emissions of Particulate Matter <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.35	The Permittee must limit emissions of Particulate Matter <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.36	The Permittee must limit emissions of Particulate Matter <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.37	The Permittee must limit emissions of Particulate Matter <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.38	The Permittee must limit emissions of PM < 10 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.39	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.40	The Permittee must limit emissions of PM < 10 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.41	The Permittee must limit emissions of PM < 10 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.42	The Permittee must limit emissions of PM < 10 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.43	The Permittee must limit emissions of PM < 10 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.44	The Permittee must limit emissions of PM < 10 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM10 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.45	The Permittee must limit emissions of PM < 10 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM10. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.46	The Permittee must limit emissions of PM < 2.5 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.47	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour

Requirement number	Requirement and citation
	rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.48	The Permittee must limit emissions of PM < 2.5 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.49	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.50	The Permittee must limit emissions of PM < 2.5 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.51	The Permittee must limit emissions of PM < 2.5 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.15.52	The Permittee must limit emissions of PM < 2.5 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM2.5 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.53	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM2.5. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.54	The Permittee must limit emissions of Carbon Monoxide <= 0.10 grams per horsepower-hour 24-hour rolling average (0.13 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.55	The Permittee must limit emissions of Carbon Monoxide <= 0.14 grams per horsepower-hour 24-hour rolling average (0.19 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.56	The Permittee must limit emissions of Carbon Monoxide <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.57	The Permittee must limit emissions of Carbon Monoxide <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.58	The Permittee must limit emissions of Carbon Monoxide <= 2.51 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.59	The Permittee must limit emissions of Carbon Monoxide <= 3.78 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation

Requirement number	Requirement and citation
	of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.60	The Permittee must limit emissions of Carbon Monoxide <= 3.71 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 10.60 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.61	The Permittee must limit emissions of Carbon Monoxide <= 0.50 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 21 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.62	The Permittee must limit emissions of Volatile Organic Compounds <= 0.13 grams per horsepower-hour 24-hour rolling average (as methane, 0.17 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.63	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 grams per horsepower-hour 24-hour rolling average (as methane, 0.21 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.64	The Permittee must limit emissions of Volatile Organic Compounds <= 0.22 grams per horsepower-hour 24-hour rolling average (as methane, 0.30 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.65	The Permittee must limit emissions of Volatile Organic Compounds <= 0.17 grams per horsepower-hour 24-hour rolling average (as methane, 0.23 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.66	The Permittee must limit emissions of Volatile Organic Compounds <= 3.26 pounds per hour 3-hour average (as methane) when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.67	The Permittee must limit emissions of Volatile Organic Compounds <= 4.33 pounds per hour 3-hour average (as methane) when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.68	The Permittee must limit emissions of Volatile Organic Compounds <= 1.16 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 3.32 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.69	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 6.44 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.70	The Permittee must limit the Sulfur Content of Fuel <= 1000 parts per million per gallon of diesel. This

Requirement number	Requirement and citation
	limit applies when operating in AOS 2. [40 CFR 60.4207(d), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.15.71	The Permittee must limit emissions of Carbon Dioxide <= 377 grams per horsepower-hour 24-hour rolling average (512 g/kW-hr) when operating in AOS 1. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.72	The Permittee must limit emissions of Carbon Dioxide <= 494 grams per horsepower-hour 24-hour rolling average (672 g/kW-hr) when operating in AOS 2. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.73	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 72,583 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.74	The Permittee must operate EQUI 23 using good combustion practices during startup, shutdown and emergency operation. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the engine temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits, whichever occurs first. Shutdown begins when the Permittee initiates the shutdown of the engine and when fuel is no longer being introduced into the engine. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.75	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 23. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = (((MNG * 110) + ((MNG * 0.0022) * 25) + ((MNG * 0.00022) * 298)) + ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298))) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; MD = mmBtu of diesel fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0022 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 23 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.76	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 700 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.77	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 23 while operating in emergency mode. Sum the number of hours EQUI 23 operated in emergency mode for the previous 12 months. The 12-

Requirement number	Requirement and citation
	month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.78	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.79	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.15.80	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	**Engine Generator 2**
5.16.1	Alternative Operating Scenario 1 (AOS 1): Engine Generator 2 (EQUI 24) operates while firing natural gas with ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
5.16.2	Alternative Operating Scenario 2 (AOS 2): Engine Generator 2 (EQUI 24) operates while firing ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
5.16.3	Recordkeeping of Alternative Operating Scenario: On each day of operation, the Permittee shall record the alternative operating scenario in which the engine generator is operating. If the Permittee changes the alternative operating scenario, record the date and time of the change and the new alternative operating scenario in which the engine generator is operating. [Minn. R. 7007.0800, subp. 11, Minn. R. 7007.0800, subps. 4-5]
5.16.4	The Permittee must limit Operating Hours <= 241 hours per year 12-month rolling sum in burn-in operation during the 12-month period following initial startup of EQUI 24. This limit expires 366 days after initial startup of EQUI 24. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.5	The Permittee must limit Operating Hours <= 8109 hours per year 12-month rolling sum in normal operation during the 12-month period following initial startup of EQUI 24. This limit expires 366 days after initial startup of EQUI 24. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.6	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 24 operated in burn-in operation. The Permittee shall record the start time and stop time in burn-in operation. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.7	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 24 operated in normal operation. The Permittee shall record the start time and stop time in normal operation. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.8	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 24 in burn-in operation for the previous month, and 2. the total hours of EQUI 24 in burn-in operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5]
5.16.9	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 24 in normal operation for the previous month, and 2. the total hours of EQUI 24 in normal operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5]
5.16.10	Startup/Shutdown and Emergency Operation Modes:

Requirement number	Requirement and citation
	1. Startup commences upon initial firing and until 75% load is attained. 2. Shutdown begins when the fuel feed is ceased. 3. Emergency operation occurs when the unit is at less than 75% load and not in startup. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.11	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.16.12	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.16.13	Fuel type: Natural gas and Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.14	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.15	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.16	EQUI 24 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subps. IIII and JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 24. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.16.17	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.16.18	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows:

Requirement number	Requirement and citation
	40 CFR 60.4200(a); 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4204(c)(3); 40 CFR 60.4204(c)(4); 40 CFR 60.4206; 40 CFR 60.4207(d); 40 CFR 60.4211(a)(1)-(a)(3); 40 CFR 60.4211(d)(1)-(d)(3); 40 CFR 60.4213(a)-(f); 40 CFR 60.4214(a)(1)-(a)(2); 40 CFR 60.4218; 40 CFR 60.4219; 40 CFR pt. 60, subp. IIII Table 7 items (b)-(d); and 40 CFR pt. 60, subp. IIII Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.16.19	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJJ(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.16.20	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows:

Requirement number	Requirement and citation
	40 CFR 60.4230(a)(6); 40 CFR 60.4233(e); 40 CFR 60.4234; 40 CFR 60.4236(b); 40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4243(e); 40 CFR 60.4244; 40 CFR 60.4245(a)(1), (a)(2), and (a)(4); 40 CFR 60.4245(c); 40 CFR 60.4245(d); 40 CFR 60.4246(a); 40 CFR 60.4246(b); 40 CFR 60.4248; 40 CFR pt. 60, subp. JJJJ Table 1; 40 CFR pt. 60, subp. JJJJ Table 2; 40 CFR pt. 60, subp. JJJJ Table 3; and 40 CFR pt. 60, subp. JJJJ Table 4. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix K. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.16.21	The Permittee must limit emissions of Nitrogen Oxides according to the following equation in units of grams per horsepower-hour: NOx <= 6.7 * n^-0.20 or in units of grams per kilowatt-hour: NOx <= 9.0 * n^-0.20 Where: NOx = nitrogen oxide emissions, g/hp-hr or g/kW-hr n = maximum engine speed >= 130 rpm and < 2000 rpm This limit applies when operating in AOS 2. [40 CFR 60.4204(c)(3)(ii), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.16.22	The Permittee must limit emissions of Nitrogen Oxides <= 1.0 grams per horsepower-hour (1.36 g/kW-hr) or 82 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.16.23	The Permittee must limit emissions of Carbon Monoxide <= 2.0 grams per horsepower-hour (2.72 g/kW-hr) or 270 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.16.24	The Permittee must limit emissions of Volatile Organic Compounds <= 0.7 grams per horsepower-hour (0.95 g/kW-hr) or 60 ppmvd at 15% O2, not including formaldehyde, when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.16.25	The Permittee must limit emissions of Nitrogen Oxides <= 0.07 grams per horsepower-hour 24-hour

Requirement number	Requirement and citation
	rolling average (0.09 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.26	The Permittee must limit emissions of Nitrogen Oxides <= 0.39 grams per horsepower-hour 24-hour rolling average (0.53 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.27	The Permittee must limit emissions of Nitrogen Oxides <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.28	The Permittee must limit emissions of Nitrogen Oxides <= 0.49 grams per horsepower-hour 24-hour rolling average (0.66 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.29	The Permittee must limit emissions of Nitrogen Oxides <= 1.65 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.30	The Permittee must limit emissions of Nitrogen Oxides <= 10.86 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.16.31	The Permittee must limit emissions of Nitrogen Oxides <= 15.82 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 45.20 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.32	The Permittee must limit emissions of Nitrogen Oxides <= 2.16 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 90 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.33	The Permittee must limit emissions of Particulate Matter <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr), or reduce particulate matter emissions by 60% or more. This limit applies when operating in AOS 2 at greater than or equal to 75% load. [40 CFR 60.4204(c)(4), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.34	The Permittee must limit emissions of Particulate Matter <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.35	The Permittee must limit emissions of Particulate Matter <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.36	The Permittee must limit emissions of Particulate Matter <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM is limited to 5.05 lbs per SUSD event. Startup shall

Requirement number	Requirement and citation
	last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.37	The Permittee must limit emissions of Particulate Matter <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.38	The Permittee must limit emissions of PM < 10 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.39	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.40	The Permittee must limit emissions of PM < 10 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.41	The Permittee must limit emissions of PM < 10 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.42	The Permittee must limit emissions of PM < 10 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.43	The Permittee must limit emissions of PM < 10 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.44	The Permittee must limit emissions of PM < 10 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM10 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.45	The Permittee must limit emissions of PM < 10 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM10. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.46	The Permittee must limit emissions of PM < 2.5 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.47	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.48	The Permittee must limit emissions of PM < 2.5 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.49	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.50	The Permittee must limit emissions of PM < 2.5 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.51	The Permittee must limit emissions of PM < 2.5 micron <= 4.76 pounds per hour 3-hour average when

Requirement number	Requirement and citation
	operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.16.52	The Permittee must limit emissions of PM < 2.5 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM2.5 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.53	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM2.5. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.54	The Permittee must limit emissions of Carbon Monoxide <= 0.10 grams per horsepower-hour 24-hour rolling average (0.13 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.55	The Permittee must limit emissions of Carbon Monoxide <= 0.14 grams per horsepower-hour 24-hour rolling average (0.19 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.56	The Permittee must limit emissions of Carbon Monoxide <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.57	The Permittee must limit emissions of Carbon Monoxide <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.58	The Permittee must limit emissions of Carbon Monoxide <= 2.51 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.59	The Permittee must limit emissions of Carbon Monoxide <= 3.78 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.60	The Permittee must limit emissions of Carbon Monoxide <= 3.71 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 10.60 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.61	The Permittee must limit emissions of Carbon Monoxide <= 0.50 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 21 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.62	The Permittee must limit emissions of Volatile Organic Compounds <= 0.13 grams per horsepower-hour 24-hour rolling average (as methane, 0.17 g/kW-hr) when operating in AOS 1 and greater than

Requirement number	Requirement and citation
	or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.63	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 grams per horsepower-hour 24-hour rolling average (as methane, 0.21 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.64	The Permittee must limit emissions of Volatile Organic Compounds <= 0.22 grams per horsepower-hour 24-hour rolling average (as methane, 0.30 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.65	The Permittee must limit emissions of Volatile Organic Compounds <= 0.17 grams per horsepower-hour 24-hour rolling average (as methane, 0.23 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.66	The Permittee must limit emissions of Volatile Organic Compounds <= 3.26 pounds per hour 3-hour average (as methane) when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.67	The Permittee must limit emissions of Volatile Organic Compounds <= 4.33 pounds per hour 3-hour average (as methane) when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.68	The Permittee must limit emissions of Volatile Organic Compounds <= 1.16 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 3.32 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.69	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 6.44 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.70	The Permittee must limit the Sulfur Content of Fuel <= 1000 parts per million per gallon of diesel. This limit applies when operating in AOS 2. [40 CFR 60.4207(d), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.16.71	The Permittee must limit emissions of Carbon Dioxide <= 377 grams per horsepower-hour 24-hour rolling average (512 g/kW-hr) when operating in AOS 1. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.72	The Permittee must limit emissions of Carbon Dioxide <= 494 grams per horsepower-hour 24-hour rolling average (672 g/kW-hr) when operating in AOS 2. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.73	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 72,583 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.74	The Permittee must operate EQUI 24 using good combustion practices during startup, shutdown and emergency operation. Startup begins when fuel is introduced to the generator engine and lasts for a

Requirement number	Requirement and citation
	period of up to 30 minutes or until the engine temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits, whichever occurs first. Shutdown begins when the Permittee initiates the shutdown of the engine and when fuel is no longer being introduced into the engine. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.75	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 24. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = (((MNG * 110) + ((MNG * 0.0022) * 25) + ((MNG * 0.00022) * 298)) + ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298))) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; MD = mmBtu of diesel fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0022 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 24 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.76	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 700 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.77	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 24 while operating in emergency mode. Sum the number of hours EQUI 24 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.78	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.79	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.16.80	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	**Engine Generator 3**

Requirement number	Requirement and citation
5.17.1	Alternative Operating Scenario 1 (AOS 1): Engine Generator 3 (EQUI 25) operates while firing natural gas with ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
5.17.2	Alternative Operating Scenario 2 (AOS 2): Engine Generator 3 (EQUI 25) operates while firing ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
5.17.3	Recordkeeping of Alternative Operating Scenario: On each day of operation, the Permittee shall record the alternative operating scenario in which the engine generator is operating. If the Permittee changes the alternative operating scenario, record the date and time of the change and the new alternative operating scenario in which the engine generator is operating. [Minn. R. 7007.0800, subp. 11, Minn. R. 7007.0800, subps. 4-5]
5.17.4	The Permittee must limit Operating Hours <= 241 hours per year 12-month rolling sum in burn-in operation during the 12-month period following initial startup of EQUI 25. This limit expires 366 days after initial startup of EQUI 25. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.5	The Permittee must limit Operating Hours <= 8109 hours per year 12-month rolling sum in normal operation during the 12-month period following initial startup of EQUI 25. This limit expires 366 days after initial startup of EQUI 25. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.6	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 25 operated in burn-in operation. The Permittee shall record the start time and stop time in burn-in operation. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.7	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 25 operated in normal operation. The Permittee shall record the start time and stop time in normal operation. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.8	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 25 in burn-in operation for the previous month, and 2. the total hours of EQUI 25 in burn-in operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5]
5.17.9	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 25 in normal operation for the previous month, and 2. the total hours of EQUI 25 in normal operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5]
5.17.10	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and until 75% load is attained. 2. Shutdown begins when the fuel feed is ceased. 3. Emergency operation occurs when the unit is at less than 75% load and not in startup. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.11	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.17.12	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.17.13	Fuel type: Natural gas and Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.14	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
5.17.15	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.16	EQUI 25 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subps. IIII and JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 25. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.17.17	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.17.18	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a); 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4204(c)(3); 40 CFR 60.4204(c)(4); 40 CFR 60.4206; 40 CFR 60.4207(d); 40 CFR 60.4211(a)(1)-(a)(3); 40 CFR 60.4211(d)(1)-(d)(3); 40 CFR 60.4213(a)-(f); 40 CFR 60.4214(a)(1)-(a)(2); 40 CFR 60.4218; 40 CFR 60.4219; 40 CFR pt. 60, subp. IIII Table 7 items (b)-(d); and

Requirement number	Requirement and citation
	40 CFR pt. 60, subp. IIII Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.17.19	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJJ(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.17.20	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows: 40 CFR 60.4230(a)(6); 40 CFR 60.4233(e); 40 CFR 60.4234; 40 CFR 60.4236(b); 40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4243(e); 40 CFR 60.4244; 40 CFR 60.4245(a)(1), (a)(2), and (a)(4); 40 CFR 60.4245(c); 40 CFR 60.4245(d); 40 CFR 60.4246(a); 40 CFR 60.4246(b); 40 CFR 60.4248;

Requirement number	Requirement and citation
	40 CFR pt. 60, subp. JJJJ Table 1; 40 CFR pt. 60, subp. JJJJ Table 2; 40 CFR pt. 60, subp. JJJJ Table 3; and 40 CFR pt. 60, subp. JJJJ Table 4. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix K. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.17.21	The Permittee must limit emissions of Nitrogen Oxides according to the following equation in units of grams per horsepower-hour: NOx <= 6.7 * n^-0.20 or in units of grams per kilowatt-hour: NOx <= 9.0 * n^-0.20 Where: NOx = nitrogen oxide emissions, g/hp-hr or g/kW-hr n = maximum engine speed >= 130 rpm and < 2000 rpm This limit applies when operating in AOS 2. [40 CFR 60.4204(c)(3)(ii), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.17.22	The Permittee must limit emissions of Nitrogen Oxides <= 1.0 grams per horsepower-hour (1.36 g/kW-hr) or 82 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.17.23	The Permittee must limit emissions of Carbon Monoxide <= 2.0 grams per horsepower-hour (2.72 g/kW-hr) or 270 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.17.24	The Permittee must limit emissions of Volatile Organic Compounds <= 0.7 grams per horsepower-hour (0.95 g/kW-hr) or 60 ppmvd at 15% O2, not including formaldehyde, when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
5.17.25	The Permittee must limit emissions of Nitrogen Oxides <= 0.07 grams per horsepower-hour 24-hour rolling average (0.09 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.26	The Permittee must limit emissions of Nitrogen Oxides <= 0.39 grams per horsepower-hour 24-hour rolling average (0.53 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.27	The Permittee must limit emissions of Nitrogen Oxides <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and

Requirement number	Requirement and citation
	Minn. R. 7007.3000]
5.17.28	The Permittee must limit emissions of Nitrogen Oxides <= 0.49 grams per horsepower-hour 24-hour rolling average (0.66 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.29	The Permittee must limit emissions of Nitrogen Oxides <= 1.65 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.30	The Permittee must limit emissions of Nitrogen Oxides <= 10.86 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.17.31	The Permittee must limit emissions of Nitrogen Oxides <= 15.82 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 45.20 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.32	The Permittee must limit emissions of Nitrogen Oxides <= 2.16 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 90 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.33	The Permittee must limit emissions of Particulate Matter <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr), or reduce particulate matter emissions by 60% or more. This limit applies when operating in AOS 2 at greater than or equal to 75% load. [40 CFR 60.4204(c)(4), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.34	The Permittee must limit emissions of Particulate Matter <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.35	The Permittee must limit emissions of Particulate Matter <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.36	The Permittee must limit emissions of Particulate Matter <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.37	The Permittee must limit emissions of Particulate Matter <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.38	The Permittee must limit emissions of PM < 10 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.39	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
5.17.40	The Permittee must limit emissions of PM < 10 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.41	The Permittee must limit emissions of PM < 10 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.42	The Permittee must limit emissions of PM < 10 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.43	The Permittee must limit emissions of PM < 10 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.44	The Permittee must limit emissions of PM < 10 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM10 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.45	The Permittee must limit emissions of PM < 10 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM10. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.46	The Permittee must limit emissions of PM < 2.5 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.47	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.48	The Permittee must limit emissions of PM < 2.5 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.49	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.50	The Permittee must limit emissions of PM < 2.5 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.51	The Permittee must limit emissions of PM < 2.5 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.17.52	The Permittee must limit emissions of PM < 2.5 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM2.5 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.53	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM2.5. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.54	The Permittee must limit emissions of Carbon Monoxide <= 0.10 grams per horsepower-hour 24-hour

Requirement number	Requirement and citation
	rolling average (0.13 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.55	The Permittee must limit emissions of Carbon Monoxide <= 0.14 grams per horsepower-hour 24-hour rolling average (0.19 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.56	The Permittee must limit emissions of Carbon Monoxide <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.57	The Permittee must limit emissions of Carbon Monoxide <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.58	The Permittee must limit emissions of Carbon Monoxide <= 2.51 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.59	The Permittee must limit emissions of Carbon Monoxide <= 3.78 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.60	The Permittee must limit emissions of Carbon Monoxide <= 3.71 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 10.60 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.61	The Permittee must limit emissions of Carbon Monoxide <= 0.50 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 21 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.62	The Permittee must limit emissions of Volatile Organic Compounds <= 0.13 grams per horsepower-hour 24-hour rolling average (as methane, 0.17 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.63	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 grams per horsepower-hour 24-hour rolling average (as methane, 0.21 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.64	The Permittee must limit emissions of Volatile Organic Compounds <= 0.22 grams per horsepower-hour 24-hour rolling average (as methane, 0.30 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition:

Requirement number	Requirement and citation
	40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.65	The Permittee must limit emissions of Volatile Organic Compounds <= 0.17 grams per horsepower-hour 24-hour rolling average (as methane, 0.23 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.66	The Permittee must limit emissions of Volatile Organic Compounds <= 3.26 pounds per hour 3-hour average (as methane) when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.67	The Permittee must limit emissions of Volatile Organic Compounds <= 4.33 pounds per hour 3-hour average (as methane) when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.68	The Permittee must limit emissions of Volatile Organic Compounds <= 1.16 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 3.32 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.69	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 6.44 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.70	The Permittee must limit the Sulfur Content of Fuel <= 1000 parts per million per gallon of diesel. This limit applies when operating in AOS 2. [40 CFR 60.4207(d), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.17.71	The Permittee must limit emissions of Carbon Dioxide <= 377 grams per horsepower-hour 24-hour rolling average (512 g/kW-hr) when operating in AOS 1. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.72	The Permittee must limit emissions of Carbon Dioxide <= 494 grams per horsepower-hour 24-hour rolling average (672 g/kW-hr) when operating in AOS 2. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.73	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 72,583 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.74	The Permittee must operate EQUI 25 using good combustion practices during startup, shutdown and emergency operation. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the engine temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits, whichever occurs first. Shutdown begins when the Permittee initiates the shutdown of the engine and when fuel is no longer being introduced into the engine. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.75	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 25. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = (((MNG * 110) + ((MNG * 0.0022) * 25) + ((MNG * 0.00022) * 298)) + ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298))) / 2000

Requirement number	Requirement and citation
	Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; MD = mmBtu of diesel fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0022 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 25 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.76	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 700 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.77	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 25 while operating in emergency mode. Sum the number of hours EQUI 25 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.78	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.79	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.17.80	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	**Emergency Generator 2**
5.18.1	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.18.2	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.18.3	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.4	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.18.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800,

Requirement number	Requirement and citation
	subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.7	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.18.8	EQUI 26 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 26. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.18.9	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218;

Requirement number	Requirement and citation
	40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.18.10	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.11	The Permittee must limit emissions of NMHC+NOx <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.12	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.13	The Permittee must limit emissions of Particulate Matter <= 0.35 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.14	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.15	The Permittee must limit emissions of PM < 10 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.16	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.17	The Permittee must limit emissions of PM < 2.5 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.18	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.19	The Permittee must limit emissions of Carbon Monoxide <= 6.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.20	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.21	The Permittee must limit emissions of Volatile Organic Compounds <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.22	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 314 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.23	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.24	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.25	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R.

Requirement number	Requirement and citation
	7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.26	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
5.18.27	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 26. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 26 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.18.28	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.18.29	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 27	**Emergency Generator 3**
5.19.1	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]

Requirement number	Requirement and citation
5.19.2	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.19.3	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.4	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.19.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.7	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.19.8	EQUI 27 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 27. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.19.9	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206;

Requirement number	Requirement and citation
	40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.19.10	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.11	The Permittee must limit emissions of NMHC+NOx <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.12	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.13	The Permittee must limit emissions of Particulate Matter <= 0.35 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.14	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.15	The Permittee must limit emissions of PM < 10 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.16	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.17	The Permittee must limit emissions of PM < 2.5 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.18	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.19	The Permittee must limit emissions of Carbon Monoxide <= 6.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.20	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.21	The Permittee must limit emissions of Volatile Organic Compounds <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
5.19.22	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 314 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.23	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.24	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.25	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.26	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
5.19.27	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 27. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 27 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.19.28	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document

Requirement number	Requirement and citation
	the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.19.29	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 28	**Emergency Generator 4**
5.20.1	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.20.2	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.20.3	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.4	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.20.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.7	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R.

Requirement number	Requirement and citation
	7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.20.8	EQUI 28 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 28. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.20.9	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.20.10	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.11	The Permittee must limit emissions of NMHC+NOx <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.12	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.13	The Permittee must limit emissions of Particulate Matter <= 0.35 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.14	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.15	The Permittee must limit emissions of PM < 10 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.16	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.17	The Permittee must limit emissions of PM < 2.5 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
5.20.18	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.19	The Permittee must limit emissions of Carbon Monoxide <= 6.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.20	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.21	The Permittee must limit emissions of Volatile Organic Compounds <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.22	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 314 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.23	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.24	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.25	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.26	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
5.20.27	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 28. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 28 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.20.28	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from

Requirement number	Requirement and citation
	the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.20.29	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 29	**Emergency Generator 5**
5.21.1	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.21.2	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.21.3	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.4	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.21.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.7	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14;

Requirement number	Requirement and citation
	40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.21.8	EQUI 29 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 29. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.21.9	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.21.10	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.11	The Permittee must limit emissions of NMHC+NOx <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.12	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
5.21.13	The Permittee must limit emissions of Particulate Matter <= 0.25 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.14	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.15	The Permittee must limit emissions of PM < 10 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.16	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.17	The Permittee must limit emissions of PM < 2.5 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.18	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.19	The Permittee must limit emissions of Carbon Monoxide <= 4.44 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.20	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.21	The Permittee must limit emissions of Volatile Organic Compounds <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.22	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 231 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.23	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.24	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.25	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.26	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
5.21.27	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 29. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4;

Requirement number	Requirement and citation
	298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 29 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.21.28	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
5.21.29	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 32	**Diesel Tank #1**
5.22.1	EQUI 32 must be constructed and operated with good tank design, including: 1. Fixed roof. 2. PRV (conservation vent). 3. Submerged fill pipe. 4. Light tank color. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 33	**Diesel Tank #2**
5.23.1	EQUI 33 must be constructed and operated with good tank design, including: 1. Fixed roof. 2. PRV (conservation vent). 3. Submerged fill pipe. 4. Light tank color. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	**Emergency Generator 6**
5.24.1	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
5.24.2	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
5.24.3	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR

Requirement number	Requirement and citation
	52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.4	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
5.24.5	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.6	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.7	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
5.24.8	EQUI 43 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 43. [40 CFR 63.6590(c), Minn. R. 7011.8150]
5.24.9	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a);

Requirement number	Requirement and citation
	40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
5.24.10	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.11	The Permittee must limit emissions of NMHC+NOx <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.12	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.13	The Permittee must limit emissions of Particulate Matter <= 0.25 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.14	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.15	The Permittee must limit emissions of PM < 10 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.16	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.17	The Permittee must limit emissions of PM < 2.5 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.18	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.19	The Permittee must limit emissions of Carbon Monoxide <= 4.44 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.20	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.21	The Permittee must limit emissions of Volatile Organic Compounds <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.22	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 231 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.23	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode.

Requirement number	Requirement and citation
	[40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.24	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.25	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.26	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
5.24.27	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 43. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 43 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.24.28	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
5.24.29	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
FUGI 1	**Engine generator fuel deliveries on paved road**
5.25.1	Comply with Fugitive Emission Control Plan: The Permittee shall follow the actions and recordkeeping specified in the fugitive dust control plan in Appendix H of this permit. If the Commissioner determines the Permittee is out of compliance with Minn. R. 7011.0150 or the fugitive control plan, then the Permittee may be required to amend the control plan and/or to install and operate particulate matter ambient monitors as requested by the Commissioner. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 1	**Oxidation Catalyst**
5.26.1	The Permittee shall vent emissions from EQUI 23 to TREA 1 whenever EQUI 23 operates, and operate and maintain TREA 1 at all times that any emissions are vented to TREA 1. The Permittee shall document periods of non-operation of the control equipment TREA 1 whenever EQUI 23 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.26.2	If the Permittee replaces TREA 1, the replacement control must comply with all other requirements of TREA 1. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.26.3	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Carbon Monoxide >= 90 percent control efficiency, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.26.4	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Volatile Organic Compounds >= 90 percent control efficiency, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.26.5	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.26.6	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 1 so that the pressure drop across TREA 1 and TREA 2 does not change by more than 2.0 inches of water from the pressure drop across TREA 1 and TREA 2 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.26.7	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 34) that continuously indicates and records the inlet temperature of TREA 1. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet

Requirement number	Requirement and citation
	temperature. [Minn. R. 7007.0800, subps. 4-5]
5.26.8	The Permittee shall operate and maintain TREA 1 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
5.26.9	For periods when TREA 1 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 1 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 1 CO, VOC control efficiency limit specified in this permit; or b. The overall TREA 1 CO, VOC control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
5.26.10	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 34) and pressure drop (EQUIs 35, 36) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
5.26.11	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 34) and pressure drop (EQUIs 35, 36) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 1 operation is required. [Minn. R. 7007.0800, subps. 4-5]
5.26.12	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 34) and pressure drop monitors (EQUIs 35, 36) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.26.13	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 1 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.26.14	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 1 that includes all TREA 1 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.26.15	Corrective Actions: If TREA 1 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 1 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 1 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 1 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 2	**Selective Catalytic Reduction**
5.27.1	The Permittee shall vent emissions from EQUI 23 to TREA 2 whenever EQUI 23 operates, and operate and maintain TREA 2 at all times that any emissions are vented to TREA 2. The Permittee shall document periods of non-operation of the control equipment TREA 2 whenever EQUI 23 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.27.2	If the Permittee replaces TREA 2, the replacement control must comply with all other requirements of

Requirement number	Requirement and citation
	TREA 2. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.27.3	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Nitrogen Oxides >= 90 percent control efficiency. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.27.4	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.27.5	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 2 so that the pressure drop across TREA 1 and TREA 2 does not change by more than 2.0 inches of water from the pressure drop across TREA 1 and TREA 2 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.27.6	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 34) that continuously indicates and records the inlet temperature of TREA 2. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
5.27.7	The Permittee shall operate and maintain TREA 2 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
5.27.8	For periods when TREA 2 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 2 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 2 NOx control efficiency limit specified in this permit; or b. The overall TREA 2 NOx control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
5.27.9	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 34) and pressure drop (EQUIs 35, 36) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
5.27.10	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 34) and pressure drop (EQUIs 35, 36) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 2 operation is required. [Minn. R. 7007.0800, subps. 4-5]

Requirement number	Requirement and citation
5.27.11	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 34) and pressure drop monitors (EQUIs 35, 36) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.27.12	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 2 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.27.13	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 2 that includes all TREA 2 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.27.14	Corrective Actions: If TREA 2 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 2 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 2 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 2 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 3	**Oxidation Catalyst**
5.28.1	The Permittee shall vent emissions from EQUI 24 to TREA 3 whenever EQUI 24 operates, and operate and maintain TREA 3 at all times that any emissions are vented to TREA 3. The Permittee shall document periods of non-operation of the control equipment TREA 3 whenever EQUI 24 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.28.2	If the Permittee replaces TREA 3, the replacement control must comply with all other requirements of TREA 3. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.28.3	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Carbon Monoxide >= 90 percent control efficiency, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.28.4	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Volatile Organic Compounds >= 90 percent control efficiency, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.28.5	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.28.6	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 3 so that the pressure drop across TREA 3 and TREA 4 does not

Requirement number	Requirement and citation
	change by more than 2.0 inches of water from the pressure drop across TREA 3 and TREA 4 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.28.7	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 37) that continuously indicates and records the inlet temperature of TREA 3. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
5.28.8	The Permittee shall operate and maintain TREA 3 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
5.28.9	For periods when TREA 3 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 3 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 3 CO, VOC control efficiency limit specified in this permit; or b. The overall TREA 3 CO, VOC control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
5.28.10	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 37) and pressure drop (EQUIs 38, 39) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
5.28.11	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 37) and pressure drop (EQUIs 38, 39) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 3 operation is required. [Minn. R. 7007.0800, subps. 4-5]
5.28.12	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 37) and pressure drop monitors (EQUIs 38, 39) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.28.13	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 3 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.28.14	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 3 that includes all TREA 3 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.28.15	Corrective Actions: If TREA 3 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 3 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 3 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return

Requirement number	Requirement and citation
	the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 3 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 4	**Selective Catalytic Reduction**
5.29.1	The Permittee shall vent emissions from EQUI 24 to TREA 4 whenever EQUI 24 operates, and operate and maintain TREA 4 at all times that any emissions are vented to TREA 4. The Permittee shall document periods of non-operation of the control equipment TREA 4 whenever EQUI 24 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.29.2	If the Permittee replaces TREA 4, the replacement control must comply with all other requirements of TREA 4. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.29.3	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Nitrogen Oxides >= 90 percent control efficiency. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.29.4	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.29.5	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 4 so that the pressure drop across TREA 3 and TREA 4 does not change by more than 2.0 inches of water from the pressure drop across TREA 3 and TREA 4 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.29.6	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 37) that continuously indicates and records the inlet temperature of TREA 4. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
5.29.7	The Permittee shall operate and maintain TREA 4 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
5.29.8	For periods when TREA 4 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 4 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 4 NOx control efficiency limit specified in this permit; or b. The overall TREA 4 NOx control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the

Requirement number	Requirement and citation
	efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
5.29.9	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 37) and pressure drop (EQUIs 38, 39) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
5.29.10	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 37) and pressure drop (EQUIs 38, 39) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 4 operation is required. [Minn. R. 7007.0800, subps. 4-5]
5.29.11	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 37) and pressure drop monitors (EQUIs 38, 39) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.29.12	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 4 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.29.13	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 4 that includes all TREA 4 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.29.14	Corrective Actions: If TREA 4 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 4 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 4 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 4 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 5	**Oxidation Catalyst**
5.30.1	The Permittee shall vent emissions from EQUI 25 to TREA 5 whenever EQUI 25 operates, and operate and maintain TREA 5 at all times that any emissions are vented to TREA 5. The Permittee shall document periods of non-operation of the control equipment TREA 5 whenever EQUI 25 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.30.2	If the Permittee replaces TREA 5, the replacement control must comply with all other requirements of TREA 5. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.30.3	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Carbon Monoxide >= 90 percent control efficiency, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.30.4	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency

Requirement number	Requirement and citation
	for Volatile Organic Compounds >= 90 percent control efficiency, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.30.5	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.30.6	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 5 so that the pressure drop across TREA 5 and TREA 6 does not change by more than 2.0 inches of water from the pressure drop across TREA 5 and TREA 6 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.30.7	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 40) that continuously indicates and records the inlet temperature of TREA 5. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
5.30.8	The Permittee shall operate and maintain TREA 5 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
5.30.9	For periods when TREA 5 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 5 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 5 CO, VOC control efficiency limit specified in this permit; or b. The overall TREA 5 CO, VOC control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
5.30.10	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 40) and pressure drop (EQUIs 41, 42) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
5.30.11	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 40) and pressure drop (EQUIs 41, 42) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 5 operation is required. [Minn. R. 7007.0800, subps. 4-5]
5.30.12	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 40) and pressure drop monitors (EQUIs 41, 42) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.30.13	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 5 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp.

Requirement number	Requirement and citation
	14, Minn. R. 7007.0800, subps. 4-5]
5.30.14	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 5 that includes all TREA 5 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.30.15	Corrective Actions: If TREA 5 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 5 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 5 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 5 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 6	**Selective Catalytic Reduction**
5.31.1	The Permittee shall vent emissions from EQUI 25 to TREA 6 whenever EQUI 25 operates, and operate and maintain TREA 6 at all times that any emissions are vented to TREA 6. The Permittee shall document periods of non-operation of the control equipment TREA 6 whenever EQUI 25 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.31.2	If the Permittee replaces TREA 6, the replacement control must comply with all other requirements of TREA 6. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.31.3	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Nitrogen Oxides >= 90 percent control efficiency. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.31.4	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.31.5	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 6 so that the pressure drop across TREA 5 and TREA 6 does not change by more than 2.0 inches of water from the pressure drop across TREA 5 and TREA 6 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
5.31.6	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 40) that continuously indicates and records the inlet temperature of TREA 6. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
5.31.7	The Permittee shall operate and maintain TREA 6 in accordance with the Operation and Maintenance

Requirement number	Requirement and citation
	(O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
5.31.8	For periods when TREA 6 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 6 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 6 NOx control efficiency limit specified in this permit; or b. The overall TREA 6 NOx control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
5.31.9	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 40) and pressure drop (EQUIs 41, 42) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
5.31.10	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 40) and pressure drop (EQUIs 41, 42) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 6 operation is required. [Minn. R. 7007.0800, subps. 4-5]
5.31.11	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 40) and pressure drop monitors (EQUIs 41, 42) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.31.12	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 6 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.31.13	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 6 that includes all TREA 6 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
5.31.14	Corrective Actions: If TREA 6 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 6 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 6 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 6 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]

6. Submittal/action requirements

This section lists most of the submittals required by this permit. Please note that some submittal requirements may appear in the Limits and Other Requirements section, or, if applicable, within a Compliance Schedule section.

Requirement number	Requirement and citation

Requirement number	Requirement and citation
TFAC 1	**Xcel Energy - Blue Lake**
6.1.1	The Permittee must submit a semiannual deviations report : Due semiannually, by the 30th of January and July. The first semiannual report submitted by the Permittee must cover the calendar half-year in which the permit is issued. The first report of each calendar year covers January 1 - June 30. The second report of each calendar year covers July 1 - December 31. Submit this on form DRF-2 (Deviation Reporting Form). If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(B)(2)]
6.1.2	The Permittee must submit a compliance certification : Due annually, by the 31st of January (for the previous calendar year). Submit this on form CR-04 (Annual Compliance Certification Report). This report covers all deviations experienced during the calendar year. If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(D)]
6.1.3	The Permittee shall submit an application for permit reissuance : Due 180 calendar days before Permit Expiration Date. [Minn. R. 7007.0400, subp. 2]
6.1.4	The Permittee shall submit excess emission/downtime report : Due by 30 days after the end of each calendar quarter following permit issuance. Submit this on form DRF-1 (Excess Emissions Reporting) as amended. The EER shall indicate all periods of monitor bypass and exceedances of the limit including those allowed by an applicable standard, i.e. during startup, shutdown, and malfunctions, as well as a summary of audit results and frequencies. If no excess emissions, downtime or bypasses occurred during the quarter, submit a signed report supplying the necessary monitor data needed to verify this. [Minn. R. 7017.1110, subp. 1-2]
6.1.5	If the Permittee elects to use CEMS, they shall submit excess emission/downtime report : Due by 30 days after the end of each calendar quarter following permit issuance. Submit this on form DRF-1 (Excess Emissions Reporting) as amended. The EER shall indicate all periods of monitor bypass and exceedances of the limit including those allowed by an applicable standard, i.e. during startup, shutdown, and malfunctions, as well as a summary of audit results and frequencies. If no excess emissions, downtime or bypasses occurred during the quarter, submit a signed report supplying the necessary monitor data needed to verify this. [Minn. R. 7017.1110, subp. 1-2]
COMG 4	**NOx CEMS for EQUI 7 and EQUI 8**
6.2.1	Certification Application: The Permittee shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The Permittee shall submit the certification application in accordance with 40 CFR 75.60 and each complete certification application shall include the information specified in 40 CFR 75.60 and 40 CFR 75.63. [40 CFR 75.20(a)(2), 40 CFR 75.60(b)(1), 40 CFR 75.63]
6.2.2	Installation Notification: due 60 days before installing the continuous emissions monitoring system. The notification shall include plans and drawings of the system. [Minn. R. 7017.1040, subp. 1]
COMG 7	**CO CEMS for EQUI 7 and EQUI 8**
6.3.1	Certification Test Plan due 30 days before Certification Test. Certification Test Pretest Meeting due seven days before Certification Test. Certification Test Report due 45 days after Certification Test. Notify the commissioner prior to making any planned change or if unforeseen, within two working days, when a monitor must be recertified as outlined in Minn. R. 7017.1050, subp. 2. Test plans and reports must be submitted in a format specified by the commissioner. [40 CFR 60.7(a)(5), Minn. R. 7017.1060, subp. 1-3, Minn. R. 7017.1080]
6.3.2	CEMS Certification/Recertification Test: due 90 days after the first excess emissions report required for the CEMS or any change which invalidates the monitor's certification status as outlined in Minn. R. 7017.1050, subp. 2. [40 CFR 60.13(b), Minn. R. 7017.1010, subp. 1(A)]

Requirement number	Requirement and citation
6.3.3	Installation Notification: due 60 days before installing the continuous emissions monitoring system. The notification shall include plans and drawings of the system. [Minn. R. 7017.1040, subp. 1]
COMG 9	**O2 CEMS for EQUI 7 and EQUI 8**
6.4.1	Certification Application: The Permittee shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The Permittee shall submit the certification application in accordance with 40 CFR 75.60 and each complete certification application shall include the information specified in 40 CFR 75.60 and 40 CFR 75.63. [40 CFR 75.20(a)(2), 40 CFR 75.60(b)(1), 40 CFR 75.63]
6.4.2	Installation Notification: due 60 days before installing the continuous emissions monitoring system. The notification shall include plans and drawings of the system. [Minn. R. 7017.1040, subp. 1]
EQUI 1	**Combustion Turbine 1 (50 MW) - Turbine**
6.5.1	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
6.5.2	Opacity: The Permittee shall conduct a performance test due before 03/20/2020 and every 48 calendar months thereafter to measure opacity. The deadline for the first test is extended to 07/18/2020. Subsequent tests are due by 03/20/2024 and every 48 months thereafter. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter. Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 2	**Combustion Turbine 2 (50 MW) - Turbine**
6.6.1	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
6.6.2	Opacity: The Permittee shall conduct a performance test due before 03/12/2021 and every 48 calendar months thereafter to measure opacity. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter.

Requirement number	Requirement and citation
	Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 3	**Combustion Turbine 3 (50 MW) - Turbine**
6.7.1	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
6.7.2	Opacity: The Permittee shall conduct a performance test due before 04/15/2022 and every 48 calendar months thereafter to measure opacity. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter. Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 4	**Combustion Turbine 4 (55 MW) - Turbine**
6.8.1	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
6.8.2	Opacity: The Permittee shall conduct a performance test due before 03/29/2023 and every 48 calendar months thereafter to measure opacity. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter. Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 7	**GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)**
6.9.1	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall

Requirement number	Requirement and citation
	be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.9.2	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
6.9.3	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major

Requirement number	Requirement and citation
	amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.9.4	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	**GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)**
6.10.1	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005,

Requirement number	Requirement and citation
	subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.10.2	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
6.10.3	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing.

Requirement number	Requirement and citation
	Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.10.4	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 9	**NOx CEMS for EQUI 7**
6.11.1	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
6.11.2	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]
6.11.3	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]
EQUI 10	**CO CEMS for EQUI 7**
6.12.1	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter

Requirement number	Requirement and citation
	in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
6.12.2	Cylinder Gas Audit (CGA) Results Summary: due 30 days after end of each calendar quarter in which a CGA was conducted. [Minn. R. 7017.1180, subp. 1]
6.12.3	The Permittee must conduct a cylinder gas audit: Due by the end of each three of four calendar quarters but no more than three quarters in succession. A CGA is not required during any calendar quarter in which a RATA was performed. [40 CFR pt. 60, Appendix F, 5.1.2, Minn. R. 7017.1010, subp. 1(C)]
6.12.4	The Permittee must conduct a relative accuracy test audit: Due one of each four calendar quarters. [40 CFR pt. 60, Appendix F, 5.1.1, Minn. R. 7017.1010, subp. 1(C)]
EQUI 11	**NOx CEMS for EQUI 8**
6.13.1	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
6.13.2	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]
6.13.3	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]
EQUI 12	**CO CEMS for EQUI 8**
6.14.1	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
6.14.2	Cylinder Gas Audit (CGA) Results Summary: due 30 days after end of each calendar quarter in which a CGA was conducted. [Minn. R. 7017.1180, subp. 1]
6.14.3	The Permittee must conduct a cylinder gas audit: Due by the end of each three of four calendar quarters but no more than three quarters in succession. A CGA is not required during any calendar quarter in which a RATA was performed. [40 CFR pt. 60, Appendix F, 5.1.2, Minn. R. 7017.1010, subp. 1(C)]
6.14.4	The Permittee must conduct a relative accuracy test audit: Due one of each four calendar quarters. [40 CFR pt. 60, Appendix F, 5.1.1, Minn. R. 7017.1010, subp. 1(C)]
EQUI 23	**Engine Generator 1**
6.15.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.15.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a.

Requirement number	Requirement and citation
	The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.15.3	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.15.4	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
6.15.5	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions.

Requirement number	Requirement and citation
	The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(items c, d), Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.15.6	Carbon Monoxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 10, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.15.7	Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 60.4242(b)(2)(ii), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(item b), Minn. R. 7011.2305, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]

Requirement number	Requirement and citation
6.15.8	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 60.4245(d), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	**Engine Generator 2**
6.16.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.16.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.16.3	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval.

Requirement number	Requirement and citation
	Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.16.4	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
6.16.5	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(items c, d), Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.16.6	Carbon Monoxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall

Requirement number	Requirement and citation
	be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 10, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.16.7	Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(item b), Minn. R. 7011.2305, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
6.16.8	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval.

Requirement number	Requirement and citation
	Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 60.4245(d), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	**Engine Generator 3**
6.17.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.17.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.17.3	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.17.4	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter.

Requirement number	Requirement and citation
	If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
6.17.5	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(items c, d), Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.17.6	Carbon Monoxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 10, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance

Requirement number	Requirement and citation
	test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
6.17.7	Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(item b), Minn. R. 7011.2305, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
6.17.8	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 60.4245(d), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	**Emergency Generator 2**
6.18.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.18.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days

Requirement number	Requirement and citation
	after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.18.3	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
6.18.4	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
6.18.5	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
6.18.6	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]
EQUI 27	**Emergency Generator 3**
6.19.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.19.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.19.3	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
6.19.4	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
6.19.5	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
6.19.6	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]

Requirement number	Requirement and citation
EQUI 28	**Emergency Generator 4**
6.20.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.20.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.20.3	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
6.20.4	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
6.20.5	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
6.20.6	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]
EQUI 29	**Emergency Generator 5**
6.21.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.21.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.21.3	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
6.21.4	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]

Requirement number	Requirement and citation
6.21.5	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
6.21.6	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]
EQUI 30	**EQUI 7 O2 CEMS (diluent)**
6.22.1	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
6.22.2	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]
6.22.3	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]
EQUI 31	**EQUI 8 O2 CEMS (diluent)**
6.23.1	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
6.23.2	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]
6.23.3	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]
EQUI 43	**Emergency Generator 6**
6.24.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and

Requirement number	Requirement and citation
	the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.24.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.24.3	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
6.24.4	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
6.24.5	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
6.24.6	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]
TREA 1	**Oxidation Catalyst**
6.25.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.25.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 2	**Selective Catalytic Reduction**
6.26.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.26.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 3	**Oxidation Catalyst**

Requirement number	Requirement and citation
6.27.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.27.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 4	**Selective Catalytic Reduction**
6.28.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.28.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 5	**Oxidation Catalyst**
6.29.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.29.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 6	**Selective Catalytic Reduction**
6.30.1	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
6.30.2	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

7. Appendices

Appendix A. Insignificant activities and general applicable requirements

The table below lists the insignificant activities that are currently at the Facility and their associated general applicable requirements.

Minn. R.	Rule description of the activity	General applicable requirement
Minn. R. 7007.1300, subp. 3(A)	Fuel Use: space heaters fueled by kerosene, natural gas, or propane, less than 420,000 Btu/hr The Permittee operates two propane space heaters at 80,000 and 125,000 Btu/hr.	PM <= 0.6 or 0.4 lb/MMBtu, depending on year constructed Opacity <= 20% with exceptions (Minn. R. 7011.0510/0515)
Minn. R. 7007.1300, subp. 4	Individual units with potential or actual emissions meeting the criteria in Minn. R. 7007.1300, subp. 4(A)-(D) The Permittee operates distillate oil pumps, valves and flanges with fugitive VOC emissions. The Permittee operates two distillate oil storage tanks with capacities of 2.8 million gallons and 881,278 gallons. The Permittee operates four propane ignitors.	PM, variable depending on airflow Opacity <= 20% (Minn. R. 7011.0710/0715) Minn. R. 7011.1505 PM <= 0.6 lb/MMBtu, Opacity <= 20% with exceptions (Minn. R. 7011.0510)
Minn. R. 7008.4100	Total facility coating and cleaning usage at the stationary source that meets the requirements of Minn. R. 7008.4100 (1,000 gallons or 10,000 lbs VOC and 8,000 lbs of particulates) The Permittee operates a parts washer using VOC containing solvent.	PM, variable depending on airflow Opacity <= 20% (Minn. R. 7011.0710/0715)
Minn. R. 7008.4110	All finishing operations at a stationary source that emit only particulate matter that meet the requirements of Minn. R. 7008.4110 (10,000 lbs of particulate; installation, O & M of control equipment) The Permittee operates an abrasive blasting cabinet with particulate filtration system.	PM, variable depending on airflow Opacity <= 20% (Minn. R. 7011.0710/0715)
Minn. R. 7007.1300, subp. 3(E)	Brazing, soldering, torch-cutting, or welding equipment The Permittee operates welding equipment.	PM, variable depending on airflow Opacity <= 20% (Minn. R. 7011.0710/0715)

Appendix B. Acid Rain Permit Renewal Application

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☒ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Blue Lake Generating Plant Facility (Source) Name	State MN	Plant Code 8027

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
7	Yes
8	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

EPA Form 7610-16 (Revised 12-2016)

Blue Lake Generating Plant
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;
(2) The owners and operators of each affected source and each affected unit at the source shall:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Blue Lake Generating Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
  (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
  (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
  (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
  (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Blue Lake Generating Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name James Kuhn	
Signature	Date 3/13/18

Appendix C. 40 CFR Part 60, Subpart A—General Provisions

§ 60.1 Applicability.

(a) Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

(d) ***Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.***

(1) This paragraph applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia (“site”).

(2) Except for compliance with 40 CFR 60.49b(u), the site shall have the option of either complying directly with the requirements of this part, or reducing the site-wide emissions caps in accordance with the procedures set forth in a permit issued pursuant to 40 CFR 52.2454. If the site chooses the option of reducing the site-wide emissions caps in accordance with the procedures set forth in such permit, the requirements of such permit shall apply in lieu of the otherwise applicable requirements of this part.

(3) Notwithstanding the provisions of paragraph (d)(2) of this section, for any provisions of this part except for Subpart Kb, the owner/operator of the site shall comply with the applicable provisions of this part if the Administrator determines that compliance with the provisions of this part is necessary for achieving the objectives of the regulation and the Administrator notifies the site in accordance with the provisions of the permit issued pursuant to 40 CFR 52.2454.

§ 60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

Administrator means the Administrator of the Environmental Protection Agency or his authorized representative.

Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.

Alternative method means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable “annual asset guideline repair allowance percentage” specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any “excluded additions” as defined in IRS Publication 534, as would be done for tax purposes.

Clean coal technology demonstration project means a project using funds appropriated under the heading ‘Department of Energy-Clean Coal Technology’, up to a total amount of $2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

Continuous monitoring system means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

Equivalent method means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

Excess Emissions and Monitoring Systems Performance Report is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

Force majeure means, for purposes of § 60.8, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Isokinetic sampling means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

Monitoring device means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

One-hour period means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Owner or operator means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

Part 70 permit means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permitting authority means:

(1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or

(2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Proportional sampling means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

Reactivation of a very clean coal-fired electric utility steam generating unit means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

(1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;

(2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;

(3) Is equipped with low-NO_X burners prior to the time of commencement of operations following reactivation; and

(4) Is otherwise in compliance with the requirements of the Clean Air Act.

Reference method means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

Repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Run means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Shutdown means the cessation of operation of an affected facility for any purpose.

Six-minute period means any one of the 10 equal parts of a one-hour period.

Standard means a standard of performance proposed or promulgated under this part.

Standard conditions means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

Startup means the setting in operation of an affected facility for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement:

(1) The provisions of this part; and/or

(2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Volatile Organic Compound means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

§ 60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A - ampere

g - gram

Hz - hertz

J - joule

K - degree Kelvin

kg - kilogram

m - meter

m^3 - cubic meter

mg - milligram - 10^{-3} gram

mm - millimeter - 10^{-3} meter

Mg - megagram - 10^6 gram

mol - mole

N - newton

ng - nanogram - 10^{-9} gram

nm - nanometer - 10^{-9} meter

Pa - pascal

s - second

V - volt

W - watt

Ω - ohm

µg - microgram - 10^{-6} gram

(b) Other units of measure:

Btu - British thermal unit

°C - degree Celsius (centigrade)

cal - calorie

cfm - cubic feet per minute

cu ft - cubic feet

dcf - dry cubic feet

dcm - dry cubic meter

dscf - dry cubic feet at standard conditions

dscm - dry cubic meter at standard conditions

eq - equivalent

°F - degree Fahrenheit

ft - feet

gal - gallon

gr - grain

g-eq - gram equivalent

hr - hour

in - inch

k - 1,000

l - liter

lpm - liter per minute

lb - pound

meq - milliequivalent

min - minute

ml - milliliter

mol. wt. - molecular weight

ppb - parts per billion

ppm - parts per million

psia - pounds per square inch absolute

psig - pounds per square inch gage

°R - degree Rankine

scf - cubic feet at standard conditions

scfh - cubic feet per hour at standard conditions

scm - cubic meter at standard conditions

sec - second

sq ft - square feet

std - at standard conditions

(c) Chemical nomenclature:

CdS - cadmium sulfide

CO - carbon monoxide

CO_2 - carbon dioxide

HCl - hydrochloric acid

Hg - mercury

H_2O - water

H_2S - hydrogen sulfide

H_2SO_4 - sulfuric acid

N_2 - nitrogen

NO - nitric oxide

NO_2 - nitrogen dioxide

NO_X - nitrogen oxides

O_2 - oxygen

SO_2 - sulfur dioxide

SO_3 - sulfur trioxide

SO_X - sulfur oxides

(d) Miscellaneous:

A.S.T.M. - American Society for Testing and Materials

§ 60.4 Address.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental

Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont) Director, Enforcement and Compliance Assurance Division, U.S. EPA Region I, 5 Post Office Square - Suite 100 (04-2), Boston, MA 02109-3912, Attn: Air Compliance Clerk.

Region II (New Jersey, New York, Puerto Rico, Virgin Islands), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, NY 10278.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air Protection Division, Mail Code 3AP00, 1650 Arch Street, Philadelphia, PA 19103-2029.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, 61 Forsyth St. SW., Suite 9T43, Atlanta, Georgia 30303-8960.

Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), Director, Air and Radiation Division, U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, IL 60604-3590.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas); Director; Enforcement and Compliance Assurance Division; U.S. Environmental Protection Agency, 1201 Elm Street, Suite 500, Mail Code 6ECD, Dallas, Texas 75270-2102.

Region VII (Iowa, Kansas, Missouri, Nebraska), Director, Air and Waste Management Division, 11201 Renner Boulevard, Lenexa, Kansas 66219.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming) Director, Air and Toxics Technical Enforcement Program, Office of Enforcement, Compliance and Environmental Justice, Mail Code 8ENF-AT, 1595 Wynkoop Street, Denver, CO 80202-1129.

Region IX (Arizona, California, Hawaii and Nevada; the territories of American Samoa and Guam; the Commonwealth of the Northern Mariana Islands; the territories of Baker Island, Howland Island, Jarvis Island, Johnston Atoll, Kingman Reef, Midway Atoll, Palmyra Atoll, and Wake Islands; and certain U.S. Government activities in the freely associated states of the Republic of the Marshall Islands, the Federated States of Micronesia, and the Republic of Palau), Director, Air Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, CA 94105.

Region X (Alaska, Oregon, Idaho, Washington), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, WA 98101.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(1) [Reserved]

(2) State of Alabama: Alabama Department of Environmental Management, P.O. Box 301463, Montgomery, Alabama 36130-1463.

(3) State of Alaska, Department of Environmental Conservation, Pouch O, Juneau, AK 99811.

(4) Arizona:

Arizona Department of Environmental Quality, 1110 West Washington Street, Phoenix, AZ 85007.

Maricopa County Air Quality Department, 1001 North Central Avenue, Suite 900, Phoenix, AZ 85004.

Pima County Department of Environmental Quality, 33 North Stone Avenue, Suite 700, Tucson, AZ 85701.

Pinal County Air Quality Control District, 31 North Pinal Street, Building F, Florence, AZ 85132.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(5) State of Arkansas: Chief, Division of Air Pollution Control, Arkansas Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, AR 72209.

(6) California:

Amador County Air Pollution Control District, 12200-B Airport Road, Jackson, CA 95642.

Antelope Valley Air Quality Management District, 43301 Division Street, Suite 206, Lancaster, CA 93535.

Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA 94109.

Butte County Air Quality Management District, 2525 Dominic Drive, Suite J, Chico, CA 95928.

Calaveras County Air Pollution Control District, 891 Mountain Ranch Road, San Andreas, CA 95249.

Colusa County Air Pollution Control District, 100 Sunrise Blvd., Suite A-3, Colusa, CA 95932-3246.

El Dorado County Air Quality Management District, 2850 Fairlane Court, Bldg. C, Placerville, CA 95667-4100.

Eastern Kern Air Pollution Control District, 2700 “M” Street, Suite 302, Bakersfield, CA 93301-2370.

Feather River Air Quality Management District, 1007 Live Oak Blvd., Suite B-3, Yuba City, CA 95991.

Glenn County Air Pollution Control District, 720 N. Colusa Street, P.O. Box 351, Willows, CA 95988-0351.

Great Basin Unified Air Pollution Control District, 157 Short Street, Suite 6, Bishop, CA 93514-3537.

Imperial County Air Pollution Control District, 150 South Ninth Street, El Centro, CA 92243-2801.

Lake County Air Quality Management District, 885 Lakeport Blvd., Lakeport, CA 95453-5405.

Lassen County Air Pollution Control District, 707 Nevada Street, Suite 1, Susanville, CA 96130.

Mariposa County Air Pollution Control District, P.O. Box 5, Mariposa, CA 95338.

Mendocino County Air Quality Management District, 306 E. Gobbi Street, Ukiah, CA 95482-5511.

Modoc County Air Pollution Control District, 619 North Main Street, Alturas, CA 96101.

Mojave Desert Air Quality Management District, 14306 Park Avenue, Victorville, CA 92392-2310.

Monterey Bay Unified Air Pollution Control District, 24580 Silver Cloud Court, Monterey, CA 93940.

North Coast Unified Air Quality Management District, 2300 Myrtle Avenue, Eureka, CA 95501-3327.

Northern Sierra Air Quality Management District, 200 Litton Drive, Suite 320, P.O. Box 2509, Grass Valley, CA 95945-2509.

Northern Sonoma County Air Pollution Control District, 150 Matheson Street, Healdsburg, CA 95448-4908.

Placer County Air Pollution Control District, 3091 County Center Drive, Suite 240, Auburn, CA 95603.

Sacramento Metropolitan Air Quality Management District, 777 12th Street, Third Floor, Sacramento, CA 95814-1908.

San Diego County Air Pollution Control District, 10124 Old Grove Road, San Diego, CA 92131-1649.

San Joaquin Valley Air Pollution Control District, 1990 E. Gettysburg, Fresno, CA 93726.

San Luis Obispo County Air Pollution Control District, 3433 Roberto Court, San Luis Obispo, CA 93401-7126.

Santa Barbara County Air Pollution Control District, 260 North San Antonio Road, Suite A, Santa Barbara, CA 93110-1315.

Shasta County Air Quality Management District, 1855 Placer Street, Suite 101, Redding, CA 96001-1759.

Siskiyou County Air Pollution Control District, 525 So. Foothill Drive, Yreka, CA 96097-3036.

South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91765-4182.

Tehama County Air Pollution Control District, P.O. Box 8069 (1750 Walnut Street), Red Bluff, CA 96080-0038.

Tuolumne County Air Pollution Control District, 22365 Airport, Columbia, CA 95310.

Ventura County Air Pollution Control District, 669 County Square Drive, 2nd Floor, Ventura, CA 93003-5417.

Yolo-Solano Air Quality Management District, 1947 Galileo Court, Suite 103, Davis, CA 95616-4882.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(7) State of Colorado, Department of Public Health and Environment, 4300 Cherry Creek Drive South, Denver, CO 80222-1530.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(8) State of Connecticut, Compliance Analysis and Coordination Unit, Bureau of Air Management, Department of Energy and Environmental Protection, 79 Elm Street, 5th Floor, Hartford, CT 06106-5127.

(9) State of Delaware, Department of Natural Resources & Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19903.

(10) District of Columbia, Department of Public Health, Air Quality Division, 51 N Street, NE., Washington, DC 20002.

(11) State of Florida: Florida Department of Environmental Protection, Division of Air Resources Management, 2600 Blair Stone Road, MS 5500, Tallahassee, Florida 32399-2400.

(12) State of Georgia: Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, 4244 International Parkway, Suite 120, Atlanta, Georgia 30354.

(13) Hawaii:

Clean Air Branch, Hawaii Department of Health, 919 Ala Moana Blvd., Suite 203, Honolulu, HI 96814.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(14) State of Idaho, Department of Health and Welfare, Statehouse, Boise, ID 83701.

(15) State of Illinois: Illinois Environmental Protection Agency, 1021 North Grand Avenue East, Springfield, Illinois 62794.

(16) State of Indiana: Indiana Department of Environmental Management, Office of Air Quality, 100 North Senate Avenue, Indianapolis, Indiana 46204.

(17) State of Iowa: Iowa Department of Natural Resources, Environmental Protection Division, Air Quality Bureau, 7900 Hickman Road, Suite 1, Urbandale, IA 50322.

(18) State of Kansas: Kansas Department of Health and Environment, Bureau of Air and Radiation, 1000 S.W. Jackson, Suite 310, Topeka, KS 66612-1366.

(19) Commonwealth of Kentucky: Kentucky Department for Environmental Protection, Division for Air Quality, 300 Sower Boulevard, 2nd Floor, Frankfort, Kentucky 40601 or local agency, Louisville Metro Air Pollution Control District, 701 W. Ormsby Ave., Suite 303, Louisville, Kentucky 40203.

(20) State of Louisiana: Louisiana Department of Environmental Quality, P.O. Box 4301, Baton Rouge, Louisiana 70821-4301.

Note:

For a list of delegated standards for Louisiana (excluding Indian country), see paragraph (e)(2) of this section.

(21) State of Maine, Maine Department of Environmental Protection, Bureau of Air Quality, 17 State House Station, Augusta, ME 04333-0017.

(22) State of Maryland, Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland 21230.

(23) Commonwealth of Massachusetts, Massachusetts Department of Environmental Protection, Division of Air and Climate Programs, One Winter Street, Boston, MA 02108.

(24) State of Michigan: Michigan Department of Natural Resources and Environment, Air Quality Division, P.O. Box 30028, Lansing, Michigan 48909.

(25) State of Minnesota: Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road North, St. Paul, Minnesota 55155.

(26) State of Mississippi: Hand Deliver or Courier: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, 515 East Amite Street, Jackson, Mississippi 39201, Mailing Address: Mississippi Department of Environmental Quality, Office of Pollution Control, Air Division, P.O. Box 2261, Jackson, Mississippi 39225.

(27) State of Missouri: Missouri Department of Natural Resources, Division of Environmental Quality, P.O. Box 176, Jefferson City, MO 65102.

(28) State of Montana, Department of Environmental Quality, 1520 E. 6th Ave., PO Box 200901, Helena, MT 59620-0901.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(29) State of Nebraska, Nebraska Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, NE 68509.

Lincoln-Lancaster County Health Department, Division of Environmental Health, 2200 St. Marys Avenue, Lincoln, NE 68502

(30) Nevada:

Nevada Division of Environmental Protection, 901 South Stewart Street, Suite 4001, Carson City, NV 89701-5249.

Clark County Department of Air Quality and Environmental Management, 500 S. Grand Central Parkway, 1st Floor, P.O. Box 555210, Las Vegas, NV 89155-5210.

Washoe County Health District, Air Quality Management Division, 1001 E. 9th Street, Building A, Suite 115A, Reno, NV 89520.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(31) State of New Hampshire, New Hampshire Department of Environmental Services, Air Resources Division, 29 Hazen Drive, P.O. Box 95, Concord, NH 03302-0095.

(32) State of New Jersey: New Jersey Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, NJ 08625.

(1) The following table lists the specific source and pollutant categories that have been delegated to the states in Region II. The (X) symbol is used to indicate each category that has been delegated.

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
D	Fossil-Fuel Fired Steam Generators for Which Construction Commenced After August 17, 1971 (Steam Generators and Lignite Fired Steam Generators)	X	X	X	X
Da	Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978	X		X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
F	Portland Cement Plants	X	X	X	X

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
G	Nitric Acid Plants	X	X	X	X
H	Sulfuric Acid Plants	X	X	X	X
I	Asphalt Concrete Plants	X	X	X	X
J	Petroleum Refineries - (All Categories)	X	X	X	X
K	Storage Vessels for Petroleum Liquids Constructed After June 11, 1973, and prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids Constructed After May 18, 1978	X	X	X	
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Ingot Production Plants	X	X	X	X
N	Iron and Steel Plants	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate	X	X	X	X
Y	Coal Preparation Plants	X	X	X	X
Z	Ferroally Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces	X	X	X	X
AAa	Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels in Steel Plants	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	
DD	Grain Elevators	X	X	X	
EE	Surface Coating of Metal Furniture	X	X	X	

	Subpart	State			
		New Jersey	New York	Puerto Rico	Virgin Islands
GG	Stationary Gas Turbines	X	X	X	
HH	Lime Plants	X	X	X	
KK	Lead Acid Battery Manufacturing Plants	X	X		
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light-Duty Truck Surface Coating Operations	X	X		
NN	Phosphate Rock Plants	X	X		
PP	Ammonium Sulfate Manufacturing Plants	X	X		
QQ	Graphic Art Industry Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of Volatile Organic Compounds in Synthetic Organic Chemical Manufacturing Industry	X		X	
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals	X	X	X	
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	
HHH	Synthetic Fiber Production Facilities	X		X	
JJJ	Petroleum Dry Clearners	X	X	X	
KKK	Equipment Leaks of VOC from Onshore Natural Gas Processing Plants				
LLL	Onshore Natural Gas Processing Plants; SO_2 Emissions		X		
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	

(33) State of New Mexico: New Mexico Environment Department, P.O. Box 5469, Santa Fe, New Mexico 87502-5469. Note: For a list of delegated standards for New Mexico (excluding Bernalillo County and Indian country), see paragraph (e)(1) of this section.

(34) New York: New York State Department of Environmental Conservation, 50 Wolf Road Albany, New York 12233, attention: Division of Air Resources.

(35) State of North Carolina: North Carolina Department of Environmental Quality, Division of Air Quality, 1641 Mail Service Center, Raleigh, North Carolina 27699-1641 or local agencies, Forsyth County Office of Environmental Assistance and Protection, 201 North Chestnut Street, Winston-Salem, North Carolina 27101-4120; Mecklenburg County Land Use and Environmental Services Agency, Air Quality, 2145 Suttle Avenue, Charlotte, North Carolina 28208; Western North Carolina Regional Air Quality Agency, 125 S. Lexington Ave., Suite 101, Asheville, North Carolina 28801-3661.

(36) State of North Dakota, North Dakota Department of Environmental Quality, 918 East Divide Avenue, Bismarck, ND 58501-1947.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(37) State of Ohio:

(i) Medina, Summit and Portage Counties; Director, Akron Regional Air Quality Management District, 146 South High Street, Room 904, Akron, OH 44308.

(ii) Stark County; Director, Canton City Health Department, Air Pollution Control Division, 420 Market Avenue North, Canton, Ohio 44702-1544.

(iii) Butler, Clermont, Hamilton, and Warren Counties; Director, Hamilton County Department of Environmental Services, 250 William Howard Taft Road, Cincinnati, Ohio 45219-2660.

(iv) Cuyahoga County; Commissioner, Cleveland Department of Public Health, Division of Air Quality, 75 Erieview Plaza 2nd Floor, Cleveland, Ohio 44114.

(v) Clark, Darke, Greene, Miami, Montgomery, and Preble Counties; Director, Regional Air Pollution Control Agency, 117 South Main Street, Dayton, Ohio 45422-1280.

(vi) Lucas County and the City of Rossford (in Wood County); Director, City of Toledo, Division of Environmental Services, 348 South Erie Street, Toledo, OH 43604.

(vii) Adams, Brown, Lawrence, and Scioto Counties; Portsmouth Local Air Agency, 605 Washington Street, Third Floor, Portsmouth, OH 45662.

(viii) Allen, Ashland, Auglaize, Crawford, Defiance, Erie, Fulton, Hancock, Hardin, Henry, Huron, Marion, Mercer, Ottawa, Paulding, Putnam, Richland, Sandusky, Seneca, Van Wert Williams, Wood (Except City of Rossford), and Wyandot Counties; Ohio Environmental Protection Agency, Northwest District Office, Air Pollution Control, 347 North Dunbridge Road, Bowling Green, Ohio 43402.

(ix) Ashtabula, Caroll, Colombiana, Holmes, Lorain, and Wayne Counties; Ohio Environmental Protection Agency, Northeast District Office, Air Pollution Unit, 2110 East Aurora Road, Twinsburg, OH 44087.

(x) Athens, Belmont, Coshocton, Gallia, Guemsey, Harrison, Hocking, Jackson, Jefferson, Meigs, Monroe, Morgan, Muskingum, Noble, Perry, Pike, Ross, Tuscarawas, Vinton, and Washington Counties; Ohio Environmental Protection Agency, Southeast District Office, Air Pollution Unit, 2195 Front Street, Logan, OH 43138.

(xi) Champaign, Clinton, Highland, Logan, and Shelby Counties; Ohio Environmental Protection Agency, Southwest District Office, Air Pollution Unit, 401 East Fifth Street, Dayton, Ohio 45402-2911.

(xii) Delaware, Fairfield, Fayette, Franklin, Knox, Licking, Madison, Morrow, Pickaway, and Union Counties; Ohio Environmental Protection Agency, Central District Office, Air Pollution control, 50 West Town Street, Suite 700, Columbus, Ohio 43215.

(xiii) Geauga and Lake Counties; Lake County General Health District, Air Pollution Control, 33 Mill Street, Painesville, OH 44077.

(xiv) Mahoning and Trumbull Counties; Mahoning-Trumbull Air Pollution Control Agency, 345 Oak Hill Avenue, Suite 200, Youngstown, OH 44502.

(38) State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, OK 73152.

(i) Oklahoma City and County: Director, Oklahoma City-County Health Department, 921 Northeast 23rd Street, Oklahoma City, OK 73105.

(ii) Tulsa County: Tulsa City-County Health Department, 4616 East Fifteenth Street, Tulsa, OK 74112.

(39) State of Oregon.

(i) Oregon Department of Environmental Quality (ODEQ), 811 SW Sixth Avenue, Portland, OR 97204-1390, *http://www.deq.state.or.us.*

(ii) Lane Regional Air Pollution Authority (LRAPA), 1010 Main Street, Springfield, Oregon 97477, *http://www.lrapa.org.*

(40)

(i) City of Philadelphia, Department of Public Health, Air Management Services, 321 University Avenue, Philadelphia, Pennsylvania 19104.

(ii) Commonwealth of Pennsylvania, Department of Environmental Protection, Bureau of Air Quality Control, P.O. Box 8468, 400 Market Street, Harrisburg, Pennsylvania 17105.

(iii) Allegheny County Health Department, Bureau of Environmental Quality, Division of Air Quality, 301 39th Street, Pittsburgh, Pennsylvania 15201.

(41) State of Rhode Island, Rhode Island Department of Environmental Management, Office of Air Resources, 235 Promenade Street, Providence, RI 02908.

(42) State of South Carolina: South Carolina Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

(43) State of South Dakota, Air Quality Program, Department of Agriculture and Natural Resources, Joe Foss Building, 523 East Capitol, Pierre, SD 57501-3181.

(44) State of Tennessee: Tennessee Department of Environment and Conservation, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue, 15th Floor, Nashville, Tennessee 37243, or local agencies, Knox County Air Quality Management - Department of Public Health, 140 Dameron Avenue, Knoxville, Tennessee 37917; Metro Public Health Department, Pollution Control Division, 2500 Charlotte Ave., Nashville, Tennessee 37209; Chattanooga-Hamilton County Air Pollution Control Bureau, 6125 Preservation Drive, Chattanooga, Tennessee 37416; Shelby County Health Department, Pollution Control Section, 814 Jefferson Avenue, Memphis, Tennessee 38105.

(45) State of Texas, Texas Air Control Board, 6330 Highway 290 East, Austin, TX 78723.

(46) State of Utah, Division of Air Quality, Department of Environmental Quality, P.O. Box 144820, Salt Lake City, UT 84114-4820.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(47) State of Vermont, Agency of Natural Resources, Department of Environmental Conservation, Air Quality and Climate Division, Davis 2, One National Life Drive, Montpelier, VT 05620-3802.

(48) Commonwealth of Virginia, Department of Environmental Quality, 629 East Main Street, Richmond, Virginia 23219.

(49) ***State of Washington.***

(i) Washington State Department of Ecology (Ecology), P.O. Box 47600, Olympia, WA 98504-7600, *http://www.ecy.wa.gov/*

(ii) Benton Clean Air Authority (BCAA), 650 George Washington Way, Richland, WA 99352-4289, *http://www.bcaa.net/*

(iii) Northwest Air Pollution Control Authority (NWAPA), 1600 South Second St., Mount Vernon, WA 98273-5202, *http://www.nwair.org/*

(iv) Olympic Regional Clean Air Agency (ORCAA), 909 Sleater-Kinney Road S.E., Suite 1, Lacey, WA 98503-1128, *http://www.orcaa.org/*

(v) Puget Sound Clean Air Agency (PSCAA), 110 Union Street, Suite 500, Seattle, WA 98101-2038, *http://www.pscleanair.org/*

(vi) Spokane County Air Pollution Control Authority (SCAPCA), West 1101 College, Suite 403, Spokane, WA 99201, *http://www.scapca.org/*

(vii) Southwest Clean Air Agency (SWCAA), 1308 NE. 134th St., Vancouver, WA 98685-2747, *http://www.swcleanair.org/*

(viii) Yakima Regional Clean Air Authority (YRCAA), 6 South 2nd Street, Suite 1016, Yakima, WA 98901, *http://co.yakima.wa.us/cleanair/default.htm*

(ix) The following table lists the delegation status of the New Source Performance Standards for the State of Washington. An “X” indicates the subpart has been delegated, subject to all the conditions and limitations set forth in Federal law and the letters granting delegation. Some authorities cannot be delegated and are retained by EPA. Refer to the letters granting delegation for a discussion of these retained authorities. The dates noted at the end of the table indicate the effective dates of Federal rules that have been delegated. Authority for implementing and enforcing any amendments made to these rules after these effective dates are not delegated.

NSPS Subparts Delegated to Washington Air Agencies

Subpart[1]	Washington						
	Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]

Subpart[1]	Washington							
	Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]
A General Provisions	X	X	X	X	X	X	X	X
B Adoption and Submittal of State Plans for Designated Facilities								
C Emission Guidelines and Compliance Times								
Cb Large Municipal Waste Combustors that are Constructed on or before September 20, 1994 (Emission Guidelines and Compliance Times)								
Cc Municipal Solid Waste Landfills (Emission Guidelines and Compliance Times)								
Cd Sulfuric Acid Production Units (Emission Guidelines and Compliance Times)								
Ce Hospital/Medical/Infectious Waste Incinerators (Emission Guidelines and Compliance Times)								
D Fossil-Fuel-Fired Steam Generators for which Construction is Commenced after August 17, 1971	X	X	X	X	X	X	X	X
Da Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978	X	X	X	X	X	X	X	X
Db Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X	X	X	X	X
Dc Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X	X	X	X	X
E Incinerators	X	X	X	X	X	X	X	X
Ea Municipal Waste Combustors for which Construction is Commenced after December 20, 1989 and on or before September 20, 1994	X	X	X	X	X	X	X	X
Eb - Large Municipal Waste Combustors		X		X	X	X		
Ec - Hospital/Medical/Infectious Waste Incinerators	X	X	X	X	X	X		
F Portland Cement Plants	X	X	X	X	X	X	X	X
G Nitric Acid Plants	X	X	X	X	X	X	X	X
H Sulfuric Acid Plants	X	X	X	X	X	X	X	X
I Hot Mix Asphalt Facilities	X	X	X	X	X	X	X	X
J Petroleum Refineries	X	X	X	X	X	X	X	X
K Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced	X	X	X	X	X	X	X	X

Subpart[1]	Washington Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]
after June 11, 1973 and prior to May 19, 1978								
Ka Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced after May 18, 1978 and prior to July 23, 1984	X	X	X	X	X	X	X	X
Kb VOC Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984	X	X	X	X	X	X	X	X
L Secondary Lead Smelters	X	X	X	X	X	X	X	X
M Secondary Brass and Bronze Production Plants	X	X	X	X	X	X	X	X
N Primary Emissions from Basic Oxygen Process Furnaces for which Construction is Commenced after June 11, 1973	X	X	X	X	X	X	X	X
Na Secondary Emissions from Basic Oxygen Process Steel-making Facilities for which Construction is Commenced after January 20, 1983	X	X	X	X	X	X	X	X
O Sewage Treatment Plants	X	X	X	X	X	X	X	X
P Primary Copper Smelters	X	X	X	X	X	X	X	X
Q Primary Zinc Smelters	X	X	X	X	X	X	X	X
R Primary Lead Smelters	X	X	X	X	X	X	X	X
S Primary Aluminum Reduction Plants[10]	X							
T Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X	X	X	X	X
U Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X	X	X	X	X
V Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X	X	X	X	X
W Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X	X	X	X	X
X Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X	X	X	X	X
Y Coal Preparation Plants	X	X	X	X	X	X	X	X
Z Ferroalloy Production Facilities	X	X	X	X	X	X	X	X
AA Steel Plants: Electric Arc Furnaces Constructed after October 21, 1974 and on or before August 17, 1983	X	X	X	X	X	X	X	X
AAa Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed after August 7, 1983	X	X	X	X	X	X	X	X

Subpart[1]	Washington							
	Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]
BB Kraft Pulp Mills[11]	X							
CC Glass Manufacturing Plants	X	X	X	X	X	X	X	X
DD Grain Elevators	X	X	X	X	X	X	X	X
EE Surface Coating of Metal Furniture	X	X	X	X	X	X	X	X
GG Stationary Gas Turbines	X	X	X	X	X	X	X	X
HH Lime Manufacturing Plants	X	X	X	X	X	X	X	X
KK Lead-Acid Battery Manufacturing Plants	X	X	X	X	X	X	X	X
LL Metallic Mineral Processing Plants	X	X	X	X	X	X	X	X
MM Automobile and Light Duty Truck Surface Coating Operations	X	X	X	X	X	X	X	X
NN Phosphate Rock Plants	X	X	X	X	X	X	X	X
PP Ammonium Sulfate Manufacture	X	X	X	X	X	X	X	X
QQ Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X	X	X	X	X
RR Pressure Sensitive Tape and Label Surface Coating Standards	X	X	X	X	X	X	X	X
SS Industrial Surface Coating: Large Appliances	X	X	X	X	X	X	X	X
TT Metal Coil Surface Coating	X	X	X	X	X	X	X	X
UU Asphalt Processing and Asphalt Roof Manufacture	X	X	X	X	X	X	X	X
VV Equipment Leaks of VOC in Synthetic Organic Chemical Manufacturing Industry	X	X	X	X	X	X	X	X
WW Beverage Can Surface Coating Industry	X	X	X	X	X	X	X	X
XX Bulk Gasoline Terminals	X	X	X	X	X	X	X	X
AAA New Residential Wood Heaters								
BBB Rubber Tire Manufacturing Industry	X	X	X	X	X	X	X	X
DDD VOC Emissions from Polymer Manufacturing Industry	X	X	X	X	X	X	X	X
FFF Flexible Vinyl and Urethane Coating and Printing	X	X	X	X	X	X	X	X
GGG Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X	X	X	X	X
HHH Synthetic Fiber Production Facilities	X	X	X	X	X	X	X	X
III VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Air Oxidation Unit Processes	X	X	X	X	X	X	X	X

Subpart[1]	Washington							
	Ecology[2]	BCAA[3]	NWAPA[4]	ORCAA[5]	PSCAA[6]	SCAPCA[7]	SWCAA[8]	YRCAA[9]
JJJ Petroleum Dry Cleaners	X	X	X	X	X	X	X	X
KKK Equipment Leaks of VOC from Onshore Natural Gas Processing Plants	X	X	X	X	X	X	X	X
LLL Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	X	X	X	X	X
NNN VOC Emissions from Synthetic Organic Chemical Manufacturing Industry Distillation Operations	X	X	X	X	X	X	X	X
OOO Nonmetallic Mineral Processing Plants			X		X		X	
PPP Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X	X	X	X	X
QQQ VOC Emissions from Petroleum Refinery Wastewater Systems	X	X	X	X	X	X	X	X
RRR VOCs from Synthetic Organic Chemical Manufacturing Industry Reactor Processes	X	X	X	X	X	X	X	X
SSS Magnetic Tape Coating Facilities	X	X	X	X	X	X	X	X
TTT Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X	X	X	X	X
UUU Calciners and Dryers in Mineral Industries	X	X	X	X	X	X	X	X
VVV Polymeric Coating of Supporting Substrates Facilities	X	X	X	X	X	X	X	X
WWW Municipal Solid Waste Landfills	X	X	X	X	X	X	X	X
AAAA Small Municipal Waste Combustion Units for which Construction is Commenced after August 30, 1999 or for which Modification or Reconstruction is Commenced after June 6, 2001	X	X		X	X	X		X
BBBB Small Municipal Waste Combustion Units Constructed on or before August 30, 1999 (Emission Guidelines and Compliance Times)								
CCCC Commercial and Industrial Solid Waste Incineration Units for which Construction is Commenced after November, 30, 1999 or for which Modification or Reconstruction is Commenced on or after June 1, 2001	X	X		X	X	X		X
DDDD Commercial and Industrial Solid Waste Incineration Units that Commenced Construction on or before November 30, 1999 (Emission Guidelines and Compliance Times)								

[1] Any authority within any subpart of this part that is not delegable, is not delegated. Please refer to Attachment B to the delegation letters for a listing of the NSPS authorities excluded from delegation.

[2] Washington State Department of Ecology, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[3] Benton Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[4] Northwest Air Pollution Authority, for all NSPS delegated, as in effect on July 1, 2000.

[5] Olympic Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[6] Puget Sound Clean Air Authority, for all NSPS delegated, as in effect on July 1, 2002.

[7] Spokane County Air Pollution Control Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[8] Southwest Clean Air Agency, for all NSPS delegated, as in effect on July 1, 2000.

[9] Yakima Regional Clean Air Authority, for 40 CFR 60.17(h)(1), (h)(2), (h)(3) and 40 CFR part 60, subpart AAAA, as in effect on June 6, 2001; for 40 CFR part 60, subpart CCCC, as in effect on June 1, 2001; and for all other NSPS delegated, as in effect February 20, 2001.

[10] Subpart S of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Primary Aluminum Plants, pursuant to Washington Administrative Code 173-415-010.

[11] Subpart BB of this part is not delegated to local agencies in Washington because the Washington State Department of Ecology retains sole authority to regulate Kraft and Sulfite Pulping Mills, pursuant to Washington State Administrative Code 173-405-012 and 173-410-012.

(50) State of West Virginia, Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE., Charleston, West Virginia 25304.

(51) State of Wisconsin: Wisconsin Department of Natural Resouces, 101 South Webster St., P.O. Box 7921, Madison, Wisconsin 53707-7921.

(52) State of Wyoming, Department of Environmental Quality, Air Quality Division, Herschler Building, 122 West 25th Street, Cheyenne, WY 82002.

Note:

For a table listing Region VIII's NSPS delegation status, see paragraph (c) of this section.

(53) Territory of Guam: Guam Environmental Protection Agency, P.O. Box 22439 GMF, Barrigada, Guam 96921.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(54) Commonwealth of Puerto Rico: Commonwealth of Puerto Rico Environmental Quality Board, P.O. Box 11488, Santurce, PR 00910, Attention: Air Quality Area Director (see table under § 60.4(b)(FF)(1)).

(55) U.S. Virgin Islands: U.S. Virgin Islands Department of Conservation and Cultural Affairs, P.O. Box 578, Charlotte Amalie, St. Thomas, VI 00801.

(56) American Samoa: American Samoa Environmental Protection Agency, P.O. Box PPA, Pago Pago, American Samoa 96799.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(57) Commonwealth of the Northern Mariana Islands: CNMI Division of Environmental Quality, P.O. Box 501304, Saipan, MP 96950.

Note:

For tables listing the delegation status of agencies in Region IX, see paragraph (d) of this section.

(c) The delegation status table for New Source Performance Standards for Region VIII can be found online at *http://www2.epa.gov/region8/air-program.*

(d) The following tables list the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region IX. The (X) symbol is used to indicate each standard that has been delegated. The following provisions of this subpart are not delegated: §§ 60.4(b), 60.8(b), 60.9, 60.11(b), 60.11(e), 60.13(a), 60.13(d)(2), 60.13(g), 60.13(i).

(1) ***Arizona.*** The following table identifies delegations for Arizona:

Table 3 to Paragraph (d)(1) - Delegation Status for New Source Performance Standards for Arizona

	Subpart	**Air pollution control agency**			
		Arizona DEQ	**Maricopa County**	**Pima County**	**Pinal County**
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	X
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X	X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced	X	X	X	

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
	After June 20, 1996				
F	Portland Cement Plants	X		X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011		X	X	
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X		X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X		X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X		X	X
Q	Primary Zinc Smelters	X		X	X
R	Primary Lead Smelters	X		X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X
BB	Kraft Pulp Mills	X	X	X	X
BBa	Kraft Pulp Mill Sources for which Construction, Reconstruction or Modification Commenced after May 23, 2013		X	X	
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	X	
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals	X	X	X	X
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X		X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X		X	
HHH	Synthetic Fiber Production Facilities	X	X	X	X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	X	X
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	X
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X		X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification After July 17, 2014		X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001	X	X	X	
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X	
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X	
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X	X	
KKKK	Stationary Combustion Turbines	X	X	X	
LLLL	New Sewage Sludge Incineration Units			X	
MMMM	Emissions Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	X			
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution		X	X	
OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015		X	X	

	Subpart	Air pollution control agency			
		Arizona DEQ	Maricopa County	Pima County	Pinal County
QQQQ	Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces		X	X	
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units		X	X	

(2) ***California.*** The following tables identify delegations for each of the local air pollution control agencies of California.

(i) Delegations for Amador County Air Pollution Control District, Antelope Valley Air Quality Management District, Bay Area Air Quality Management District, and Butte County Air Quality Management District are shown in the following table:

Table 4 to Paragraph (d)(2)(i) - Delegation Status for New Source Performance Standards for Amador County APCD, Antelope Valley AQMD, Bay Area AQMD, and Butte County AQMD

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
A	General Provisions		X		
Ba	Adoption and Submittal of State Plans for Designated Facilities		X		
Cf	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills		X		
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X	X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units		X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators		X	X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996		X		
F	Portland Cement Plants		X	X	
G	Nitric Acid Plants		X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011		X		

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
H	Sulfuric Acid Plant		X	X	
I	Hot Mix Asphalt Facilities		X	X	
J	Petroleum Refineries		X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X	X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X	X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X	X	
L	Secondary Lead Smelters		X	X	
M	Secondary Brass and Bronze Production Plants		X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X	X	
O	Sewage Treatment Plants		X	X	
P	Primary Copper Smelters		X	X	
Q	Primary Zinc Smelters		X	X	
R	Primary Lead Smelters		X	X	
S	Primary Aluminum Reduction Plants		X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	X	
Y	Coal Preparation and Processing Plants		X	X	
Z	Ferroalloy Production Facilities		X	X	

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X	X	
BB	Kraft Pulp Mills		X	X	
BBa	Kraft Pulp Mill Sources for which Construction, Reconstruction or Modification Commenced after May 23, 2013		X		
CC	Glass Manufacturing Plants		X	X	
DD	Grain Elevators		X	X	
EE	Surface Coating of Metal Furniture		X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines		X	X	
HH	Lime Manufacturing Plants		X	X	
KK	Lead-Acid Battery Manufacturing Plants		X	X	
LL	Metallic Mineral Processing Plants		X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations		X	X	
NN	Phosphate Rock Plants		X	X	
PP	Ammonium Sulfate Manufacture		X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X	X	
SS	Industrial Surface Coating: Large Appliances		X	X	
TT	Metal Coil Surface Coating		X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture		X	X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing		X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry		X	X	
XX	Bulk Gasoline Terminals				

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
AAA	New Residential Wood Heaters		X	X	
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X	X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries		X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		
HHH	Synthetic Fiber Production Facilities		X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners		X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X	X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions		X		
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X	X	
OOO	Nonmetallic Mineral Processing Plants		X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		
SSS	Magnetic Tape Coating Facilities		X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	
WWW	Municipal Solid Waste Landfills		X		
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or		X		

	Subpart	Air pollution control agency			
		Amador County APCD	Antelope Valley AQMD	Bay Area AQMD	Butte County AQMD
	Modification After July 17, 2014				
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001		X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		
DDDD	Emissions Guidelines and Compliance Times for Commercial and Industrial Solid Waste Incineration Units		X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines		X		
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X		
KKKK	Stationary Combustion Turbines		X		
LLLL	New Sewage Sludge Incineration Units		X		
MMMM	Emissions Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units		X		
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution		X		
OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After September 18, 2015		X		
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units		X		
UUUUa	Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units		X		

(ii) [Reserved]

(iii) Delegations for Glenn County Air Pollution Control District, Great Basin Unified Air Pollution Control District, Imperial County Air Pollution Control District, and Kern County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Glenn County APCD, Great Basin Unified APCD, Imperial County APCD, and Kern County APCD

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X		X
Db	Industrial-Commercial-Institutional Steam Generating Units		X		X
Dc	Small Industrial Steam Generating Units		X		X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X		X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X		X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X		X
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X		X
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture		X		X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X
KK	Lead-Acid Battery Manufacturing Plants		X		X
LL	Metallic Mineral Processing Plants		X		X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X		X
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X		X
SS	Industrial Surface Coating: Large Appliances		X		X
TT	Metal Coil Surface Coating		X		X
UU	Asphalt Processing and Asphalt Roofing Manufacture		X		X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry		X		X
WW	Beverage Can Surface Coating Industry		X		X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters		X		X
BBB	Rubber Tire Manufacturing Industry		X		X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X		X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing		X		X
GGG	Equipment Leaks of VOC in Petroleum Refineries		X		X
HHH	Synthetic Fiber Production Facilities		X		X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		X
JJJ	Petroleum Dry Cleaners		X		X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X		X
LLL	Onshore Natural Gas Processing: SO2 Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X		X
OOO	Nonmetallic Mineral Processing Plants		X		X
PPP	Wool Fiberglass Insulation Manufacturing Plants		X		X

	Subpart	Air pollution control agency			
		Glenn County APCD	Great Basin Unified APCD	Imperial County APCD	Kern County APCD
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X		X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X
SSS	Magnetic Tape Coating Facilities		X		X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries		X		X
VVV	Polymeric Coating of Supporting Substrates Facilities		X		X
WWW	Municipal Solid Waste Landfills				X

(iv) Delegations for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Lake County Air Quality Management District, Lassen County Air Pollution Control District, Mariposa County Air Pollution Control District, and Mendocino County Air Pollution Control District

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
A	General Provisions	X			X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X			X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X			X
Db	Industrial-Commercial-Institutional Steam Generating Units	X			
Dc	Small Industrial Steam Generating Units	X			X
E	Incinerators	X			X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X			X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
F	Portland Cement Plants	X			X
G	Nitric Acid Plants	X			X
H	Sulfuric Acid Plants	X			X
I	Hot Mix Asphalt Facilities	X			X
J	Petroleum Refineries	X			X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X			X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X			X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X			X
L	Secondary Lead Smelters	X			X
M	Secondary Brass and Bronze Production Plants	X			X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X			X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X			X
O	Sewage Treatment Plants	X			X
P	Primary Copper Smelters	X			X
Q	Primary Zinc Smelters	X			X
R	Primary Lead Smelters	X			X
S	Primary Aluminum Reduction Plants	X			X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X			X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X			X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X			X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X			X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
Y	Coal Preparation Plants	X			X
Z	Ferroalloy Production Facilities	X			X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X			X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X			X
BB	Kraft Pulp Mills	X			X
CC	Glass Manufacturing Plants	X			X
DD	Grain Elevators	X			X
EE	Surface Coating of Metal Furniture	X			X
FF	(Reserved)				
GG	Stationary Gas Turbines	X			X
HH	Lime Manufacturing Plants	X			X
KK	Lead-Acid Battery Manufacturing Plants	X			X
LL	Metallic Mineral Processing Plants	X			X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X			X
NN	Phosphate Rock Plants	X			X
PP	Ammonium Sulfate Manufacture	X			X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X			X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X			X
SS	Industrial Surface Coating: Large Appliances	X			X
TT	Metal Coil Surface Coating	X			X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X			X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X			X
WW	Beverage Can Surface Coating Industry	X			X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters	X			X

	Subpart	Air pollution control agency			
		Lake County AQMD	Lassen County APCD	Mariposa County AQMD	Mendocino County AQMD
BBB	Rubber Tire Manufacturing Industry	X			X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X			X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X			X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X			X
HHH	Synthetic Fiber Production Facilities	X			X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X			X
JJJ	Petroleum Dry Cleaners	X			X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X			X
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X			X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X			X
OOO	Nonmetallic Mineral Processing Plants	X			X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X			X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X			X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X			
SSS	Magnetic Tape Coating Facilities	X			X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				
UUU	Calciners and Dryers in Mineral Industries	X			X
VVV	Polymeric Coating of Supporting Substrates Facilities	X			X
WWW	Municipal Solid Waste Landfills	X			

(v) Delegations for Modoc Air Pollution Control District, Mojave Desert Air Quality Management District, Monterey Bay Unified Air Pollution Control District and North Coast Unified Air Quality Management District are shown in the following table:

Table 7 to Paragraph (d)(2)(v) - Delegation Status for New Source Performance Standards for Modoc County APCD, Mojave Desert AQMD, Monterey Bay Unified APCD, and North Coast Unified AQMD

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	X	
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X		
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994		X		
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996		X		
F	Portland Cement Plants	X	X	X	X
G	Nitric Acid Plants	X	X	X	X
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	X
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007		X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for	X	X	X	X

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
	Which Construction, Reconstruction, or Modification Commenced After July 23, 1984				
L	Secondary Lead Smelters	X	X	X	X
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	X
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	X
Q	Primary Zinc Smelters	X	X	X	X
R	Primary Lead Smelters	X	X	X	X
S	Primary Aluminum Reduction Plants	X	X	X	X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	X
Y	Coal Preparation and Processing Plants	X	X	X	X
Z	Ferroalloy Production Facilities	X	X	X	X
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	X
BB	Kraft Pulp Mills	X	X	X	X
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	X
FF	(Reserved)				

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
GG	Stationary Gas Turbines	X	X	X	X
HH	Lime Manufacturing Plants	X	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	X
LL	Metallic Mineral Processing Plants	X	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	X
NN	Phosphate Rock Plants	X	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	X	X
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	X
SS	Industrial Surface Coating: Large Appliances	X	X	X	X
TT	Metal Coil Surface Coating	X	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006		X		
WW	Beverage Can Surface Coating Industry	X	X	X	X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	X
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	X
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006		X		
HHH	Synthetic Fiber Production Facilities	X	X	X	X

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X		
JJJ	Petroleum Dry Cleaners	X	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	X
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X		
SSS	Magnetic Tape Coating Facilities	X	X	X	X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	X
UUU	Calciners and Dryers in Mineral Industries		X	X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	X	X
WWW	Municipal Solid Waste Landfills		X	X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001		X		
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001		X		
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006		X		
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines		X	X	

	Subpart	Air pollution control agency			
		Modoc County APCD	Mojave Desert AQMD	Monterey Bay Unified APCD	North Coast Unified AQMD
JJJJ	Stationary Spark Ignition Internal Combustion Engines		X	X	
KKKK	Stationary Combustion Turbines		X	X	
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(vi) Delegations for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District are shown in the following table:

Delegation Status for New Source Performance Standards for Northern Sierra Air Quality Management District, Northern Sonoma County Air Pollution Control District, Placer County Air Pollution Control District, and Sacramento Metropolitan Air Quality Management District

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	Northern Sonoma County APCD	Placer County APCD	Sacramento Metropolitan AQMD
A	General Provisions		X		X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X		X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X		X
Db	Industrial-Commercial-Institutional Steam Generating Units				X
Dc	Small Industrial Steam Generating Units				X
E	Incinerators		X		X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994				X
Eb	Municipal Waste Combustors Constructed After September 20, 1994				X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996				X
F	Portland Cement Plants		X		X
G	Nitric Acid Plants		X		X
H	Sulfuric Acid Plants		X		X

		Air pollution control agency			
	Subpart	**Northern Sierra AQMD**	**Northern Sonoma County APCD**	**Placer County APCD**	**Sacramento Metropolitan AQMD**
I	Hot Mix Asphalt Facilities		X		X
J	Petroleum Refineries		X		X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X		X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X		X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984				X
L	Secondary Lead Smelters		X		X
M	Secondary Brass and Bronze Production Plants		X		X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X		X
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983				X
O	Sewage Treatment Plants		X		X
P	Primary Copper Smelters		X		X
Q	Primary Zinc Smelters		X		X
R	Primary Lead Smelters		X		X
S	Primary Aluminum Reduction Plants		X		X
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X		X
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X		X
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X		X
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X		X
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X		X
Y	Coal Preparation Plants		X		X
Z	Ferroalloy Production Facilities		X		X

		Air pollution control agency			
	Subpart	**Northern Sierra AQMD**	**Northern Sonoma County APCD**	**Placer County APCD**	**Sacramento Metropolitan AQMD**
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X		X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983				X
BB	Kraft pulp Mills		X		X
CC	Glass Manufacturing Plants		X		X
DD	Grain Elevators		X		X
EE	Surface Coating of Metal Furniture				X
FF	(Reserved)				
GG	Stationary Gas Turbines		X		X
HH	Lime Manufacturing Plants		X		X
KK	Lead-Acid Battery Manufacturing Plants				X
LL	Metallic Mineral Processing Plants				X
MM	Automobile and Light Duty Trucks Surface Coating Operations		X		X
NN	Phosphate Rock Plants				X
PP	Ammonium Sulfate Manufacture		X		X
QQ	Graphic Arts Industry: Publication Rotogravure Printing				X
RR	Pressure Sensitive Tape and Label Surface Coating Operations				X
SS	Industrial Surface Coating: Large Appliances				X
TT	Metal Coil Surface Coating				X
UU	Asphalt Processing and Asphalt Roofing Manufacture				X
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry				X
WW	Beverage Can Surface Coating Industry				X
XX	Bulk Gasoline Terminals				
AAA	New Residential Wool Heaters				X
BBB	Rubber Tire Manufacturing Industry				X
CCC	(Reserved)				

	Subpart	Air pollution control agency			
		Northern Sierra AQMD	**Northern Sonoma County APCD**	**Placer County APCD**	**Sacramento Metropolitan AQMD**
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry				X
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing				X
GGG	Equipment Leaks of VOC in Petroleum Refineries				X
HHH	Synthetic Fiber Production Facilities				X
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes				X
JJJ	Petroleum Dry Cleaners				X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants				X
LLL	Onshore Natural Gas Processing: SO_2 Emissions				X
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations				X
OOO	Nonmetallic Mineral Processing Plants				X
PPP	Wool Fiberglass Insulation Manufacturing Plants				X
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems				X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes				X
SSS	Magnetic Tape Coating Facilities				X
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines				X
UUU	Calciners and Dryers in Mineral Industries				X
VVV	Polymeric Coating of Supporting Substrates Facilities				X
WWW	Municipal Solid Waste Landfills				X

(vii) Delegations for San Diego County Air Pollution Control District, San Joaquin Valley Unified Air Pollution Control District, San Luis Obispo County Air Pollution Control District, and Santa Barbara County Air Pollution Control District are shown in the following table:

Table 9 to Paragraph (d)(2)(vii) - Delegation Status for New Source Performance Standards for San Diego County APCD, San Joaquin Valley Unified APCD, San Luis Obispo County APCD, and Santa Barbara County APCD

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
A	General Provisions	X	X	X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	X	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	X	X
E	Incinerators	X	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X		X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X			X
F	Portland Cement Plants	X	X	X	
G	Nitric Acid Plants	X	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X	X	X	
I	Hot Mix Asphalt Facilities	X	X	X	X
J	Petroleum Refineries	X	X	X	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007				X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	X	X
L	Secondary Lead Smelters	X	X	X	X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
M	Secondary Brass and Bronze Production Plants	X	X	X	X
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	X	
O	Sewage Treatment Plants	X	X	X	X
P	Primary Copper Smelters	X	X	X	
Q	Primary Zinc Smelters	X	X	X	
R	Primary Lead Smelters	X	X	X	
S	Primary Aluminum Reduction Plants	X	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X	X	X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X	X	X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X	X	X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X	X	X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X	X	X	
Y	Coal Preparation and Processing Plants	X	X	X	
Z	Ferroalloy Production Facilities	X	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	X	
BB	Kraft Pulp Mills	X	X	X	
CC	Glass Manufacturing Plants	X	X	X	X
DD	Grain Elevators	X	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X	
FF	(Reserved)				
GG	Stationary Gas Turbines	X	X	X	X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
HH	Lime Manufacturing Plants	X	X	X	
KK	Lead-Acid Battery Manufacturing Plants	X	X	X	
LL	Metallic Mineral Processing Plants	X	X	X	
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X	
NN	Phosphate Rock Plants	X	X	X	
PP	Ammonium Sulfate Manufacture	X	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X	
TT	Metal Coil Surface Coating	X	X	X	
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006				X
WW	Beverage Can Surface Coating Industry	X	X	X	
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters	X	X	X	X
BBB	Rubber Tire Manufacturing Industry	X	X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X		
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006				X
HHH	Synthetic Fiber Production Facilities	X	X	X	

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X		
JJJ	Petroleum Dry Cleaners	X	X	X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X		
OOO	Nonmetallic Mineral Processing Plants	X	X	X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X	
UUU	Calciners and Dryers in Mineral Industries	X	X	X	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001	X			X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X			X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X			X
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines	X			X

	Subpart	Air pollution control agency			
		San Diego County APCD	San Joaquin Valley Unified APCD	San Luis Obispo County APCD	Santa Barbara County APCD
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X			X
KKKK	Stationary Combustion Turbines	X			X
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				
QQQQ	Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces	X			
TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	X			

(viii) Delegations for Shasta County Air Quality Management District, Siskiyou County Air Pollution Control District, South Coast Air Quality Management District, and Tehama County Air Pollution Control District are shown in the following table:

Delegation Status for New Source Performance Standards for Shasta County AQMD, Siskiyou County APCD, South Coast AQMD, and Tehama County APCD

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
A	General Provisions	X	X	X	
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X		X	
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978			X	
Db	Industrial-Commercial-Institutional Steam Generating Units			X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units			X	
E	Incinerators	X		X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994			X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994			X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996			X	
F	Portland Cement Plants	X		X	
G	Nitric Acid Plants	X		X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011				
H	Sulfuric Acid Plant	X		X	
I	Hot Mix Asphalt Facilities	X		X	
J	Petroleum Refineries	X		X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007			X	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X		X	
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984			X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984			X	
L	Secondary Lead Smelters	X		X	
M	Secondary Brass and Bronze Production Plants	X		X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X		X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983			X	
O	Sewage Treatment Plants	X		X	
P	Primary Copper Smelters	X		X	
Q	Primary Zinc Smelters	X		X	
R	Primary Lead Smelters	X		X	
S	Primary Aluminum Reduction Plants	X		X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	X		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	X		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	X		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	X		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	X		X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
Y	Coal Preparation and Processing Plants	X		X	
Z	Ferroalloy Production Facilities	X		X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X		X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983			X	
BB	Kraft Pulp Mills	X		X	
CC	Glass Manufacturing Plants			X	
DD	Grain Elevators	X		X	
EE	Surface Coating of Metal Furniture			X	
FF	(Reserved)				
GG	Stationary Gas Turbines			X	
HH	Lime Manufacturing Plants	X		X	
KK	Lead-Acid Battery Manufacturing Plants			X	
LL	Metallic Mineral Processing Plants			X	
MM	Automobile and Light Duty Trucks Surface Coating Operations			X	
NN	Phosphate Rock Plants			X	
PP	Ammonium Sulfate Manufacture			X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing			X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations			X	
SS	Industrial Surface Coating: Large Appliances			X	
TT	Metal Coil Surface Coating			X	
UU	Asphalt Processing and Asphalt Roofing Manufacture			X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing			X	
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006			X	
WW	Beverage Can Surface Coating Industry			X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	Siskiyou County APCD	South Coast AQMD	Tehama County APCD
XX	Bulk Gasoline Terminals				
AAA	New Residential Wood Heaters		X	X	
BBB	Rubber Tire Manufacturing Industry		X	X	
CCC	(Reserved)				
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry			X	
EEE	(Reserved)				
FFF	Flexible Vinyl and Urethane Coating and Printing			X	
GGG	Equipment Leaks of VOC in Petroleum Refineries			X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			X	
HHH	Synthetic Fiber Production Facilities			X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes			X	
JJJ	Petroleum Dry Cleaners			X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants			X	
LLL	Onshore Natural Gas Processing: SO_2 Emissions			X	
MMM	(Reserved)				
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations			X	
OOO	Nonmetallic Mineral Processing Plants			X	
PPP	Wool Fiberglass Insulation Manufacturing Plants			X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes			X	
SSS	Magnetic Tape Coating Facilities		X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	X	
UUU	Calciners and Dryers in Mineral Industries			X	

	Subpart	Air pollution control agency			
		Shasta County AQMD	**Siskiyou County APCD**	**South Coast AQMD**	**Tehama County APCD**
VVV	Polymeric Coating of Supporting Substrates Facilities			X	
WWW	Municipal Solid Waste Landfills			X	
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001	X	X	X	
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001			X	
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006			X	
GGGG	(Reserved)				
HHHH	(Reserved)				
IIII	Stationary Compression Ignition Internal Combustion Engines			X	
JJJJ	Stationary Spark Ignition Internal Combustion Engines			X	
KKKK	Stationary Combustion Turbines			X	
LLLL	New Sewage Sludge Incineration Units				
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution				

(ix) Delegations for Tuolumne County Air Pollution Control District, Ventura County Air Pollution Control District, and Yolo-Solano Air Quality Management District are shown in the following table:

Table 11 to Paragraph (d)(2)(ix) - Delegation Status for New Source Performance Standards for Tuolumne County APCD, Ventura County APCD, and Yolo-Solano AQMD

	Subpart	Air pollution control agency		
		Tuolumne County APCD	**Ventura County APCD**	**Yolo-Solano AQMD**
A	General Provisions		X	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971		X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978		X	

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
Db	Industrial-Commercial-Institutional Steam Generating Units		X	X
Dc	Small Industrial-Commercial-Institutional Steam Generating Units		X	
E	Incinerators		X	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994		X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994			
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996			
F	Portland Cement Plants		X	
G	Nitric Acid Plants		X	
H	Sulfuric Acid Plant		X	
I	Hot Mix Asphalt Facilities		X	X
J	Petroleum Refineries		X	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978		X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984		X	
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984		X	
L	Secondary Lead Smelters		X	
M	Secondary Brass and Bronze Production Plants		X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973		X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983		X	
O	Sewage Treatment Plants		X	
P	Primary Copper Smelters		X	

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
Q	Primary Zinc Smelters		X	
R	Primary Lead Smelters		X	
S	Primary Aluminum Reduction Plants		X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	
Y	Coal Preparation and Processing Plants		X	
Z	Ferroalloy Production Facilities		X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983		X	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983		X	
BB	Kraft Pulp Mills		X	
CC	Glass Manufacturing Plants		X	
DD	Grain Elevators		X	
EE	Surface Coating of Metal Furniture		X	
FF	(Reserved)			
GG	Stationary Gas Turbines		X	
HH	Lime Manufacturing Plants		X	
KK	Lead-Acid Battery Manufacturing Plants		X	
LL	Metallic Mineral Processing Plants		X	
MM	Automobile and Light Duty Trucks Surface Coating Operations		X	

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
NN	Phosphate Rock Plants		X	
PP	Ammonium Sulfate Manufacture		X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing		X	
RR	Pressure Sensitive Tape and Label Surface Coating Operations		X	
SS	Industrial Surface Coating: Large Appliances		X	
TT	Metal Coil Surface Coating		X	
UU	Asphalt Processing and Asphalt Roofing Manufacture		X	
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing		X	
WW	Beverage Can Surface Coating Industry		X	
XX	Bulk Gasoline Terminals			
AAA	New Residential Wood Heaters		X	
BBB	Rubber Tire Manufacturing Industry		X	
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry		X	
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing		X	
GGG	Equipment Leaks of VOC in Petroleum Refineries		X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006			
HHH	Synthetic Fiber Production Facilities		X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes		X	
JJJ	Petroleum Dry Cleaners		X	
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants		X	

	Subpart	Air pollution control agency		
		Tuolumne County APCD	Ventura County APCD	Yolo-Solano AQMD
LLL	Onshore Natural Gas Processing: SO_2 Emissions		X	
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations		X	
OOO	Nonmetallic Mineral Processing Plants		X	X
PPP	Wool Fiberglass Insulation Manufacturing Plants		X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems		X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes		X	
SSS	Magnetic Tape Coating Facilities		X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines		X	
UUU	Calciners and Dryers in Mineral Industries		X	
VVV	Polymeric Coating of Supporting Substrates Facilities		X	
WWW	Municipal Solid Waste Landfills	X	X	

(3) ***Hawaii.*** The following table identifies delegations for Hawaii:

Delegation Status for New Source Performance Standards for Hawaii:

Delegation Status for New Source Performance Standards for Hawaii

	Subpart	Hawaii
A	General Provisions	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X
Db	Industrial-Commercial-Institutional Steam Generating Units	X
Dc	Small Industrial Steam Generating Units	X
E	Incinerators	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X

	Subpart	Hawaii
Eb	Municipal Waste Combustors Constructed After September 20, 1994	X
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X
L	Secondary Lead Smelters	
M	Secondary Brass and Bronze Production Plants	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	
O	Sewage Treatment Plants	X
P	Primary Copper Smelters	
Q	Primary Zinc Smelters	
R	Primary Lead Smelters	
S	Primary Aluminum Reduction Plants	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	
Y	Coal Preparation Plants	X
Z	Ferroalloy Production Facilities	

	Subpart	Hawaii
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X
BB	Kraft pulp Mills	
CC	Glass Manufacturing Plants	
DD	Grain Elevators	
EE	Surface Coating of Metal Furniture	
FF	(Reserved)	
GG	Stationary Gas Turbines	X
HH	Lime Manufacturing Plants	
KK	Lead-Acid Battery Manufacturing Plants	
LL	Metallic Mineral Processing Plants	
MM	Automobile and Light Duty Trucks Surface Coating Operations	
NN	Phosphate Rock Plants	
PP	Ammonium Sulfate Manufacture	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	
RR	Pressure Sensitive Tape and Label Surface Coating Operations	
SS	Industrial Surface Coating: Large Appliances	
TT	Metal Coil Surface Coating	
UU	Asphalt Processing and Asphalt Roofing Manufacture	
VV	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
WW	Beverage Can Surface Coating Industry	X
XX	Bulk Gasoline Terminals	X
AAA	New Residential Wool Heaters	
BBB	Rubber Tire Manufacturing Industry	
CCC	(Reserved)	
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	
EEE	(Reserved)	
FFF	Flexible Vinyl and Urethane Coating and Printing	

	Subpart	Hawaii
GGG	Equipment Leaks of VOC in Petroleum Refineries	X
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	
HHH	Synthetic Fiber Production Facilities	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	
JJJ	Petroleum Dry Cleaners	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	
LLL	Onshore Natural Gas Processing: SO_2 Emissions	
MMM	(Reserved)	
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X
OOO	Nonmetallic Mineral Processing Plants	X
PPP	Wool Fiberglass Insulation Manufacturing Plants	
QQQ	VOC Emissions From Petroleum Refinery Wastewater	X
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	
SSS	Magnetic Tape Coating Facilities	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	
UUU	Calciners and Dryers in Mineral Industries	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X
WWW	Municipal Solid Waste Landfills	X
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commenced After June 6, 2001	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	
GGGG	(Reserved)	
IIII	Stationary Compression Ignition Internal Combustion Engines	
JJJJ	Stationary Spark Ignition Internal Combustion Engines	
KKKK	Stationary Combustion Turbines	

(4) ***Nevada.*** The following table identifies delegations for Nevada:

Table 12 to Paragraph (d)(4) - Delegation Status for New Source Performance Standards for Nevada

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
A	General Provisions	X	X	X
Cf	Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills	X		
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X	X	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	X	X	
Db	Industrial-Commercial-Institutional Steam Generating Units	X	X	
Dc	Small Industrial-Commercial-Institutional Steam Generating Units	X	X	
E	Incinerators	X	X	X
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	X	X	
Eb	Large Municipal Waste Combustors Constructed After September 20, 1994	X	X	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	X	X	
F	Portland Cement Plants	X	X	X
G	Nitric Acid Plants	X	X	
Ga	Nitric Acid Plants For Which Construction, Reconstruction or Modification Commenced After October 14, 2011	X		
H	Sulfuric Acid Plant	X	X	
I	Hot Mix Asphalt Facilities	X	X	X
J	Petroleum Refineries	X	X	
Ja	Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007	X		
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X	X	X
Ka	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984	X	X	X
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	X	X	
L	Secondary Lead Smelters	X	X	X

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
M	Secondary Brass and Bronze Production Plants	X	X	
N	Primary Emissions from Basic Oxygen Process Furnaces for Which Construction is Commenced After June 11, 1973	X	X	
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities for Which Construction is Commenced After January 20, 1983	X	X	
O	Sewage Treatment Plants	X	X	X
P	Primary Copper Smelters	X	X	X
Q	Primary Zinc Smelters	X	X	X
R	Primary Lead Smelters	X	X	X
S	Primary Aluminum Reduction Plants	X	X	
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Acid Plants		X	
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants		X	
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants		X	
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants		X	
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities		X	
Y	Coal Preparation and Processing Plants	X	X	X
Z	Ferroalloy Production Facilities	X	X	
AA	Steel Plants: Electric Arc Furnaces Constructed After October 21, 1974 and On or Before August 17, 1983	X	X	
AAa	Steel Plants: Electric Arc Furnaces and Argon-Oxygen Decarburization Vessels Constructed After August 7, 1983	X	X	
BB	Kraft Pulp Mills		X	
CC	Glass Manufacturing Plants	X	X	
DD	Grain Elevators	X	X	X
EE	Surface Coating of Metal Furniture	X	X	X
FF	(Reserved)			
GG	Stationary Gas Turbines	X	X	X
HH	Lime Manufacturing Plants	X	X	X
KK	Lead-Acid Battery Manufacturing Plants	X	X	X

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
LL	Metallic Mineral Processing Plants	X	X	X
MM	Automobile and Light Duty Trucks Surface Coating Operations	X	X	X
NN	Phosphate Rock Plants	X	X	X
PP	Ammonium Sulfate Manufacture	X	X	
QQ	Graphic Arts Industry: Publication Rotogravure Printing	X	X	X
RR	Pressure Sensitive Tape and Label Surface Coating Operations	X	X	
SS	Industrial Surface Coating: Large Appliances	X	X	X
TT	Metal Coil Surface Coating	X	X	X
UU	Asphalt Processing and Asphalt Roofing Manufacture	X	X	X
VV	Equipment Leaks of VOC in the Synthetic Organic Industry Chemicals Manufacturing	X	X	X
VVa	Equipment Leaks of VOC in the Synthetic Organic Industry for Which Construction, Reconstruction, or Chemicals Manufacturing Modification Commenced After November 7, 2006	X	X	
WW	Beverage Can Surface Coating Industry	X	X	
XX	Bulk Gasoline Terminals	X	X	
AAA	New Residential Wood Heaters		X	
BBB	Rubber Tire Manufacturing Industry	X	X	
CCC	(Reserved)			
DDD	Volatile Organic Compounds (VOC) Emissions from the Polymer Manufacturing Industry	X	X	
EEE	(Reserved)			
FFF	Flexible Vinyl and Urethane Coating and Printing	X	X	
GGG	Equipment Leaks of VOC in Petroleum Refineries	X	X	
GGGa	Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006	X	X	
HHH	Synthetic Fiber Production Facilities	X	X	
III	Volatile Organic Compound (VOC) Emissions From the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes	X	X	
JJJ	Petroleum Dry Cleaners	X	X	X
KKK	Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	X	X	

	Subpart	Air pollution control agency		
		Nevada DEP	Clark County	Washoe County
LLL	Onshore Natural Gas Processing: SO_2 Emissions	X	X	
MMM	(Reserved)			
NNN	Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations	X	X	
OOO	Nonmetallic Mineral Processing Plants	X	X	
PPP	Wool Fiberglass Insulation Manufacturing Plants	X	X	
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	X	X	
RRR	Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes	X	X	
SSS	Magnetic Tape Coating Facilities	X	X	
TTT	Industrial Surface Coating: Surface Coating of Plastic Parts for Business Machines	X	X	X
UUU	Calciners and Dryers in Mineral Industries	X	X	X
VVV	Polymeric Coating of Supporting Substrates Facilities	X	X	X
WWW	Municipal Solid Waste Landfills	X	X	X
XXX	Municipal Solid Waste Landfills that Commenced Construction, Reconstruction, or Modification after July 17, 2014	X		
AAAA	Small Municipal Waste Combustion Units for Which Construction is Commenced After August 30, 1999 or for Which Modification or Reconstruction is Commended After June 6, 2001	X	X	X
CCCC	Commercial and Industrial Solid Waste Incineration Units for Which Construction Is Commenced After November 30, 1999 or for Which Modification or Reconstruction Is Commenced on or After June 1, 2001	X	X	X
EEEE	Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for Which Modification or Reconstruction is Commenced on or After June 16, 2006	X	X	X
GGGG	(Reserved)			
HHHH	(Reserved)			
IIII	Stationary Compression Ignition Internal Combustion Engines	X	X	X
JJJJ	Stationary Spark Ignition Internal Combustion Engines	X	X	X
KKKK	Stationary Combustion Turbines	X	X	X
LLLL	New Sewage Sludge Incineration Units		X	
OOOO	Crude Oil and Natural Gas Production, Transmission, and Distribution	X		

(5) ***Guam.*** The following table identifies delegations as of June 15, 2001:

Delegation Status for New Source Performance Standards for Guam

	Subpart	Guam
A	General Provisions	X
D	Fossil-Fuel Fired Steam Generators Constructed After August 17, 1971	X
Da	Electric Utility Steam Generating Units Constructed After September 18, 1978	
Db	Industrial-Commercial-Institutional Steam Generating Units	
Dc	Small Industrial Steam Generating Units	
E	Incinerators	
Ea	Municipal Waste Combustors Constructed After December 20, 1989 and On or Before September 20, 1994	
Eb	Municipal Waste Combustors Constructed After September 20, 1994	
Ec	Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996	
F	Portland Cement Plants	X
G	Nitric Acid Plants	
H	Sulfuric Acid Plants	
I	Hot Mix Asphalt Facilities	X
J	Petroleum Refineries	X
K	Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978	X

(e) The following lists the specific part 60 standards that have been delegated unchanged to the air pollution control agencies in Region 6.

(1) ***New Mexico.*** The New Mexico Environment Department has been delegated all part 60 standards promulgated by the EPA, except subpart AAA - Standards of Performance for New Residential Wood Heaters; and subpart QQQQ - Standards of Performance for New Residential Hydronic Heaters and Forced-Air Furnaces, as amended in the Federal Register through January 15, 2017.

(2) ***Louisiana.*** The Louisiana Department of Environmental Quality has been delegated all part 60 standards promulgated by EPA, except subpart AAA - Standards of Performance for New Residential Wood Heaters, as amended in the Federal Register through July 1, 2013.

Delegation Status for Part 60 Standards - State of Louisiana

[Excluding Indian Country]

Subpart	Source category	LDEQ[1]
A	General Provisions	Yes
Ce	Emission Guidelines and Compliance Times for Hospital/Medical/Infectious Waste Incinerators	Yes
D	Fossil Fueled Steam Generators (>250 MM BTU/hr)	Yes

Subpart	Source category	LDEQ[1]
Da	Electric Utility Steam Generating Units (>250 MM BTU/hr)	Yes
Db	Industrial-Commercial-Institutional Steam Generating Units (100 to 250 MM BTU/hr)	Yes
Dc	Industrial-Commercial-Institutional Small Steam Generating Units (10 to 100 MM BTU/hr)	Yes
E	Incinerators (>50 tons per day)	Yes
Ea	Municipal Waste Combustors	Yes
Eb	Large Municipal Waste Combustors	Yes
Ec	Hospital/Medical/Infectious Waste Incinerators	Yes
F	Portland Cement Plants	Yes
G	Nitric Acid Plants	Yes
Ga	Nitric Acid Plants (after October 14, 2011)	Yes
H	Sulfuric Acid Plants	Yes
I	Hot Mix Asphalt Facilities	Yes
J	Petroleum Refineries	Yes
Ja	Petroleum Refineries (After May 14, 2007)	Yes
K	Storage Vessels for Petroleum Liquids (After 6/11/73 & Before 5/19/78)	Yes
Ka	Storage Vessels for Petroleum Liquids (After 6/11/73 & Before 5/19/78)	Yes
Kb	Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Stg/Vessels) After 7/23/84	Yes
L	Secondary Lead Smelters Yes	Yes
M	Secondary Brass and Bronze Production Plants	Yes
N	Primary Emissions from Basic Oxygen Process Furnaces (Construction Commenced After June 11, 1973)	Yes
Na	Secondary Emissions from Basic Oxygen Process Steelmaking Facilities Construction is Commenced After January 20, 1983	Yes
O	Sewage Treatment Plants	Yes
P	Primary Copper Smelters	Yes
Q	Primary Zinc Smelters	Yes
R	Primary Lead Smelters	Yes
S	Primary Aluminum Reduction Plants	Yes
T	Phosphate Fertilizer Industry: Wet Process Phosphoric Plants	Yes
U	Phosphate Fertilizer Industry: Superphosphoric Acid Plants	Yes
V	Phosphate Fertilizer Industry: Diammonium Phosphate Plants	Yes

Subpart	Source category	LDEQ[1]
W	Phosphate Fertilizer Industry: Triple Superphosphate Plants	Yes
X	Phosphate Fertilizer Industry: Granular Triple Superphosphate Storage Facilities	Yes
Y	Coal Preparation Plants	Yes
Z	Ferroalloy Production Facilities	Yes
AA	Steel Plants: Electric Arc Furnaces After 10/21/74 & On or Before 8/17/83	Yes
AAa	Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Vessels After 8/07/83	Yes
BB	Kraft Pulp Mills	Yes
CC	Glass Manufacturing Plants	Yes
DD	Grain Elevators	Yes
EE	Surface Coating of Metal Furniture	Yes
GG	Stationary Gas Turbines	Yes
HH	Lime Manufacturing Plants	Yes
KK	Lead-Acid Battery Manufacturing Plants	Yes
LL	Metallic Mineral Processing Plants	Yes
MM	Automobile & Light Duty Truck Surface Coating Operations	Yes
NN	Phosphate Manufacturing Plants	Yes
PP	Ammonium Sulfate Manufacture	Yes
QQ	Graphic Arts Industry: Publication Rotogravure Printing	Yes
RR	Pressure Sensitive Tape and Label Surface Coating Operations	Yes
SS	Industrial Surface Coating: Large Appliances	Yes
TT	Metal Coil Surface Coating	Yes
UU	Asphalt Processing and Asphalt Roofing Manufacture	Yes
VV	VOC Equipment Leaks in the SOCMI Industry	Yes
VVa	VOC Equipment Leaks in the SOCMI Industry (After November 7, 2006)	Yes
XX	Bulk Gasoline Terminals	Yes
AAA	New Residential Wood Heaters	No
BBB	Rubber Tire Manufacturing Industry	Yes
DDD	Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry	Yes
FFF	Flexible Vinyl and Urethane Coating and Printing	Yes

Subpart	Source category	LDEQ[1]
GGG	VOC Equipment Leaks in Petroleum Refineries	Yes
HHH	Synthetic Fiber Production	Yes
III	VOC Emissions from the SOCMI Air Oxidation Unit Processes	Yes
JJJ	Petroleum Dry Cleaners	Yes
KKK	VOC Equipment Leaks From Onshore Natural Gas Processing Plants	Yes
LLL	Onshore Natural Gas Processing: SO_2 Emissions	Yes
NNN	VOC Emissions from SOCMI Distillation Operations	Yes
OOO	Nonmetallic Mineral Processing Plants	Yes
PPP	Wool Fiberglass Insulation Manufacturing Plants	Yes
QQQ	VOC Emissions From Petroleum Refinery Wastewater Systems	Yes
RRR	VOC Emissions from SOCMI Reactor Processes	Yes
SSS	Magnetic Tape Coating Operations	Yes
TTT	Industrial Surface Coating: Plastic Parts for Business Machines	Yes
UUU	Calciners and Dryers in Mineral Industries	Yes
VVV	Polymeric Coating of Supporting Substrates Facilities	Yes
WWW	Municipal Solid Waste Landfills	Yes
AAAA	Small Municipal Waste Combustion Units (Construction is Commenced After 8/30/99 or Modification/Reconstruction is Commenced After 6/06/2001)	Yes
CCCC	Commercial & Industrial Solid Waste Incineration Units (Construction is Commenced After 11/30/1999 or Modification/Reconstruction is Commenced on or After 6/01/2001)	Yes
DDDD	Emission Guidelines & Compliance Times for Commercial & Industrial Solid Waste Incineration Units (Commenced Construction On or Before 11/30/1999)	Yes
EEEE	Other Solid Waste Incineration Units (Constructed after 12/09/2004 or Modification/Reconstruction is commenced on or after 06/16/2004)	Yes
IIII	Stationary Compression Ignition Internal Combustion Engines	Yes
JJJJ	Stationary Spark Ignition Internal Combustion Engines	Yes
KKKK	Stationary Combustion Turbines (Construction Commenced After 02/18/2005)	Yes
LLLL	New Sewage Sludge Incineration Units	Yes
MMMM	Emission Guidelines and Compliance Times for Existing Sewage Sludge Incineration Units	Yes
OOOO	Crude Oil and Natural Gas Production, Transmission and Distribution	Yes

[1] The Louisiana Department of Environmental Quality (LDEQ) has been delegated all Part 60 standards promulgated by EPA, except subpart AAA - Standards of Performance for New Residential Wood Heaters - as amended in the Federal Register through July 1, 2013.

(3) ***Albuquerque-Bernalillo County Air Quality Control Board.*** The Albuquerque-Bernalillo County Air Quality Control Board has been delegated all part 60 standards promulgated by the EPA, except subpart AAA of this part and subpart QQQQ of this part as amended through January 23, 2017.

Editorial Note: For Federal Register citations affecting § 60.4, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov.*

§ 60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

§ 60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)

(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall

(1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or

(2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

§ 60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under § 60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) [Reserved]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in § 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with § 60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by § 60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by § 60.8 in lieu of Method 9 observation data as allowed by § 60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with § 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in § 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in § 60.7(c) shall both be submitted.

Figure 1 - Summary Report - Gaseous and Opacity Excess Emission and Monitoring System Performance

Pollutant (Circle One - SO_2/NO_X/TRS/H_2S/CO/Opacity)

Reporting period dates: From _____ to _____

Company:

Emission Limitation

Address:

Monitor Manufacturer and Model No.

Date of Latest CMS Certification or Audit

Process Unit(s) Description:

Total source operating time in reporting period[1]

Emission data summary[1]		**CMS performance summary[1]**	
1. Duration of excess emissions in reporting period due to:		1. CMS downtime in reporting period due to:	
a. Startup/shutdown		a. Monitor equipment malfunctions	
b. Control equipment problems		b. Non-Monitor equipment malfunctions	
c. Process problems		c. Quality assurance calibration	
d. Other known causes		d. Other known causes	
e. Unknown causes		e. Unknown causes	
2. Total duration of excess emission		2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]	%[2]	3. [Total CMS Downtime] × (100) [Total source operating time]	%[2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

[2] For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in § 60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

Name

Signature

Title

Date

(e)(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the

disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

§ 60.8 Performance tests.

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator

(1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology,

(2) approves the use of an equivalent method,

(3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance,

(4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or

(5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes

(i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and

(ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method.

(1) Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

(2) Contents of report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, the report for a

performance test shall include the elements identified in paragraphs (f)(2)(i) through (vi) of this section.

(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry System (FRS) number for the facility.

(ii) Purpose of the test including the applicable regulation(s) requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard and any process parameter component, and a brief process description.

(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.

(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.

(v) Where a test method requires you record or report, the following shall be included: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.

(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test program including his/her email address.

(g) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample

shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(1) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A-3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60, Methods 18 and 19 of appendix A-6 of part 60, Methods 20, 22, and 25A of appendix A-7 of part 60, Methods 30A and 30B of appendix A-8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. “Commercially available” means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *www.epa.gov/ttn/emc,* to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(2) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

(i) Preparing the sample;

(ii) Confirming the true concentration of the sample;

(iii) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range.

(iv) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(v) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(vi) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(vii) The AASP shall report the results from each audit sample in a timely manner to the compliance authority and then to the source owner, operator, or representative. The AASP shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.

(viii) Evaluating the acceptance limits of samples at least once every two years to determine in cooperation with the voluntary consensus standard body if they should be changed;

(ix) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(3) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that

describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

(i) Checking audit samples to confirm their true value as reported by the AASP;

(ii) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years;

(iii) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(4) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget Circular A-119. A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at *http://standards.gov/standards__gov/a119.cfm.* The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria documents do not meet the minimum technical requirements in paragraphs (g)(2) through (4)of this section, the technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, *http://www.epa.gov/ttn/emc.*

(h) Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points.

(i) Whenever the use of multiple calibration gases is required by a test method, performance specification, or quality assurance procedure in a part 60 standard or appendix, Method 205 of 40 CFR part 51, appendix M of this chapter, “Verification of Gas Dilution Systems for Field Instrument Calibrations,” may be used.

§ 60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§ 60.5 and 60.6 is governed by §§ 2.201 through 2.213 of this chapter and not by § 2.301 of this chapter.)

§ 60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by § 60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e) (1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in § 60.8 unless one of the following conditions apply. If no performance test under § 60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under § 60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in § 60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under § 60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determing compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of

the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under § 60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in § 60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by § 60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and § 60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under § 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under § 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under § 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under § 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under § 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in § 60.13(c) of this part, that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by § 60.8, the opacity observation results and observer certification required by § 60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by § 60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with § 60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

§ 60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

§ 60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part,

unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under § 60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under § 60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under § 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under § 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part, The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under § 60.8 and as described in § 60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under § 60.8 is conducted.

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d) (1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry

including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h) (1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in

each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of § 60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with < 30 minutes of unit operation under § 60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in § 60.8 of this subpart or other tests performed following the criteria in § 60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source

emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §§ 60.45(g) (2) and (3), 60.73(e), and 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

Editorial Note

Editorial Note: For Federal Register citations affecting § 60.13, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov.*

§ 60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of “Compilation of Air Pollutant Emission Factors,” EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and § 60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j) (1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project,* for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

§ 60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

§ 60.16 Priority list.

Prioritized Major Source Categories

Priority Number[1]	***Source Category***
1.	Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Volatile Organic Liquid Storage Vessels and Handling Equipment
	(a) SOCMI unit processes
	(b) Volatile organic liquid (VOL) storage vessels and handling equipment
	(c) SOCMI fugitive sources
	(d) SOCMI secondary sources
2.	Industrial Surface Coating: Cans
3.	Petroleum Refineries: Fugitive Sources
4.	Industrial Surface Coating: Paper
5.	Dry Cleaning
	(a) Perchloroethylene
	(b) Petroleum solvent
6.	Graphic Arts
7.	Polymers and Resins: Acrylic Resins

Priority Number[1]	***Source Category***
8.	Mineral Wool (Deleted)
9.	Stationary Internal Combustion Engines
10.	Industrial Surface Coating: Fabric
11.	Industrial-Commercial-Institutional Steam Generating Units.
12.	Incineration: Non-Municipal (Deleted)
13.	Non-Metallic Mineral Processing
14.	Metallic Mineral Processing
15.	Secondary Copper (Deleted)
16.	Phosphate Rock Preparation
17.	Foundries: Steel and Gray Iron
18.	Polymers and Resins: Polyethylene
19.	Charcoal Production
20.	Synthetic Rubber
	(a) Tire manufacture
	(b) SBR production
21.	Vegetable Oil
22.	Industrial Surface Coating: Metal Coil
23.	Petroleum Transportation and Marketing
24.	By-Product Coke Ovens
25.	Synthetic Fibers
26.	Plywood Manufacture
27.	Industrial Surface Coating: Automobiles
28.	Industrial Surface Coating: Large Appliances
29.	Crude Oil and Natural Gas Production
30.	Secondary Aluminum
31.	Potash (Deleted)
32.	Lightweight Aggregate Industry: Clay, Shale, and Slate[2]
33.	Glass
34.	Gypsum

Priority Number[1]	***Source Category***
35.	Sodium Carbonate
36.	Secondary Zinc (Deleted)
37.	Polymers and Resins: Phenolic
38.	Polymers and Resins: Urea-Melamine
39.	Ammonia (Deleted)
40.	Polymers and Resins: Polystyrene
41.	Polymers and Resins: ABS-SAN Resins
42.	Fiberglass
43.	Polymers and Resins: Polypropylene
44.	Textile Processing
45.	Asphalt Processing and Asphalt Roofing Manufacture
46.	Brick and Related Clay Products
47.	Ceramic Clay Manufacturing (Deleted)
48.	Ammonium Nitrate Fertilizer
49.	Castable Refractories (Deleted)
50.	Borax and Boric Acid (Deleted)
51.	Polymers and Resins: Polyester Resins
52.	Ammonium Sulfate
53.	Starch
54.	Perlite
55.	Phosphoric Acid: Thermal Process (Deleted)
56.	Uranium Refining
57.	Animal Feed Defluorination (Deleted)
58.	Urea (for fertilizer and polymers)
59.	Detergent (Deleted)

Other Source Categories

Lead acid battery manufacture[3]

Organic solvent cleaning[3]

Industrial surface coating: metal furniture[3]

Priority Number[1]	***Source Category***

Stationary gas turbines[4]

Municipal solid waste landfills[4]

[1] Low numbers have highest priority, e.g., No. 1 is high priority, No. 59 is low priority.

[2] Formerly titled “Sintering: Clay and Fly Ash”.

[3] Minor source category, but included on list since an NSPS is being developed for that source category.

[4] Not prioritized, since an NSPS for this major source category has already been promulgated.

§ 60.17 Incorporations by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the EPA must publish notice of change in the Federal Register and the material must be available to the public. All approved material is available for inspection at the EPA Docket Center, Public Reading Room, EPA WJC West, Room 3334, 1301 Constitution Ave. NW., Washington, DC, telephone number 202-566-1744, and is available from the sources listed below. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fedreg.legal@nara.gov,* or go to *www.archives.gov/federal-register/cfr/ibr-locations.html.*

(b) American Gas Association, available through ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), IBR approved for § 60.107a(d).

(2) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements (2000), IBR approved for § 60.107a(d).

(3) American Gas Association Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for § 60.107a(d).

(4) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Revised February 2006), IBR approved for § 60.107a(d).

(c) American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675-2683. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-124), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0-87258-673-5. IBR approved for §§ 60.35e and 60.55c.

(2) [Reserved]

(d) The following material is available for purchase from the American National Standards Institute (ANSI), 25 W. 43rd Street, 4th Floor, New York, NY 10036, Telephone (212) 642-4980, and is also available at the following Web site: *http://www.ansi.org*.

(1) ANSI No. C12.20-2010 American National Standard for Electricity Meters - 0.2 and 0.5 Accuracy Classes (Approved August 31, 2010), IBR approved for § 60.5535(d).

(2) [Reserved]

(e) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved for §§ 60.111(i), 60.111a(f), and 60.116b(e).

(2) API Manual of Petroleum Measurement Standards, Chapter 14 - Natural Gas Fluids Measurement, Section 1 - Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016, IBR approved for § 60.4415(a).

(3) API Manual of Petroleum Measurement Standards, Chapter 22 - Testing Protocol, Section 2 - Differential Pressure Flow Measurement Devices, First Edition, August 2005, IBR approved for § 60.107a(d).

(f) American Public Health Association, 1015 18th Street NW., Washington, DC 20036.

(1) “Standard Methods for the Examination of Water and Wastewater,” 16th edition, 1985. Method 303F: “Determination of Mercury by the Cold Vapor Technique.” Incorporated by reference for appendix A-8 to part 60, Method 29, §§ 9.2.3, 10.3, and 11.1.3.

(2) 2540 G. Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, in Standard Methods for the Examination of Water and Wastewater, 20th Edition, 1998, IBR approved for § 60.154(b).

(g) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990, Telephone (800) 843-2763, and is also available at the following Web site: *http://www.asme.org.*

(1) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§ 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(2) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for § 60.107a(d).

(3) ASME/ANSI MFC-4M-1986 (Reaffirmed 2008), Measurement of Gas Flow by Turbine Meters, IBR approved for § 60.107a(d).

(4) ASME/ANSI MFC-5M-1985 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 60.107a(d).

(5) ASME MFC-6M-1998 (Reaffirmed 2005), Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 60.107a(d).

(6) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 60.107a(d).

(7) ASME/ANSI MFC-9M-1988 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 60.107a(d).

(8) ASME MFC-11M-2006, Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 60.107a(d).

(9) ASME MFC-14M-2003, Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 60.107a(d).

(10) ASME MFC-16-2007, Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for § 60.107a(d).

(11) ASME MFC-18M-2001, Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 60.107a(d).

(12) ASME MFC-22-2007, Measurement of Liquid by Turbine Flowmeters, IBR approved for § 60.107a(d).

(13) ASME PTC 4.1-1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§ 60.46b, 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(14) ASME/ANSI PTC 19.10-1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i), and (j), 60.105a(b), (d), (f), and (g), 60.106a(a), 60.107a(a), (c), and (d), tables 1 and 3 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, §§ 60.285a(f), 60.4415(a), 60.2145(s) and (t), 60.2710(s) and (t), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c), 60.5406a(c), 60.5407a(g), 60.5413(b), 60.5413a(b), and 60.5413a(d).

(15) ASME PTC 22-2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), IBR approved for § 60.5580.

(16) ASME PTC 46-1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), IBR approved for § 60.5580.

(17) ASME QRO-1-1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§ 60.54b(a) and (b), 60.56a, 60.1185(a) and (c), and 60.1675(a) and (c).

(h) The following material is available for purchase from ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-2959, (800) 262-1373, *http://www.astm.org.*

(1) ASTM A99-76, Standard Specification for Ferromanganese, IBR approved for § 60.261.

(2) ASTM A99-82 (Reapproved 1987), Standard Specification for Ferromanganese, IBR approved for § 60.261.

(3) ASTM A100-69, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(4) ASTM A100-74, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(5) ASTM A100-93, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(6) ASTM A101-73, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(7) ASTM A101-93, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(8) ASTM A482-76, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(9) ASTM A482-93, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(10) ASTM A483-64, Standard Specification for Silicomanganese, IBR approved for § 60.261.

(11) ASTM A483-74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for § 60.261.

(12) ASTM A495-76, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(13) ASTM A495-94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(14) ASTM D86-78, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(15) ASTM D86-82, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(16) ASTM D86-90, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(17) ASTM D86-93, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(18) ASTM D86-95, Distillation of Petroleum Products, IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).

(19) ASTM D86-96, Distillation of Petroleum Products, (Approved April 10, 1996), IBR approved for §§ 60.562-2(d), 60.593(d), 60.593a(d), 60.633(h), 60.5401(f), 60.5401a(f).

(20) ASTM D129-64, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(21) ASTM D129-78, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(22) ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(23) ASTM D129-00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.335(b).

(24) ASTM D129-00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.4415(a).

(25) ASTM D240-76, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(26) ASTM D240-92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and appendix A-7: Method 19, Section 12.5.2.2.3.

(27) ASTM D240-02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, (Approved May 1, 2007), IBR approved for § 60.107a(d).

(28) ASTM D270-65, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(29) ASTM D270-75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(30) ASTM D323-82, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(31) ASTM D323-94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(32) ASTM D388-77, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(33) ASTM D388-90, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(34) ASTM D388-91, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(35) ASTM D388-95, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(36) ASTM D388-98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(37) ASTM D388-99 (Reapproved 2004) 1 Standard Classification of Coals by Rank, IBR approved for §§ 60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, 60.251, and 60.5580.

(38) ASTM D396-78, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(39) ASTM D396-89, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(40) ASTM D396-90, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(41) ASTM D396-92, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), and 60.111a(b).

(42) ASTM D396-98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b, 60.41c, 60.111(b), 60.111a(b), and 60.5580.

(43) ASTM D975-78, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(44) ASTM D975-96, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(45) ASTM D975-98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) and 60.111a(b).

(46) ASTM D975-08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.41b 60.41c, and 60.5580.

(47) ASTM D1072-80, Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).

(48) ASTM D1072-90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b).

(49) ASTM D1072-90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4415(a).

(50) ASTM D1137-53, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f).

(51) ASTM D1137-75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f).

(52) ASTM D1193-77, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(53) ASTM D1193-91, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(54) ASTM D1266-87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(55) ASTM D1266-91, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(56) ASTM D1266-98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j) and 60.335(b).

(57) ASTM D1266-98 (Reapproved 2003)$^{\epsilon,1}$ Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4415(a).

(58) ASTM D1475-60 (Reapproved 1980), Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d), appendix A-7 to part 60: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(59) ASTM D1475-90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d), appendix A-7 to part 60: Method 24, Section 6.1; and Method 24A, §§ 6.5 and 7.1.

(60) ASTM D1552-83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(61) ASTM D1552-95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(62) ASTM D1552-01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(63) ASTM D1552-03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for § 60.4415(a).

(64) ASTM D1826-77, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.

(65) ASTM D1826-94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.

(66) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, (Approved May 10, 2003), IBR approved for § 60.107a(d).

(67) ASTM D1835-87, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(68) ASTM D1835-91, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(69) ASTM D1835-97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(70) ASTM D1835-03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da, 60.41b, and 60.41c.

(71) ASTM D1945-64, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(72) ASTM D1945-76, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(73) ASTM D1945-91, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(74) ASTM D1945-96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f).

(75) ASTM D1945-03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010), IBR approved for §§ 60.107a(d), 60.5413(d), 60.5413a(d).

(76) ASTM D1946-77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(77) ASTM D1946-90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(78) ASTM D1946-90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, (Approved June 1, 2006), IBR approved for § 60.107a(d).

(79) ASTM D2013-72, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(80) ASTM D2013-86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(81) ASTM D2015-77 (Reapproved 1978), Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(82) ASTM D2015-96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§ 60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(83) ASTM D2016-74, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(84) ASTM D2016-83, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(85) ASTM D2234-76, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(86) ASTM D2234-96, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(87) ASTM D2234-97b, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(88) ASTM D2234-98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(89) ASTM D2369-81, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(90) ASTM D2369-87, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(91) ASTM D2369-90, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(92) ASTM D2369-92, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(93) ASTM D2369-93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(94) ASTM D2369-95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(95) ASTM D2369-10 (Reapproved 2015)e1, Standard Test Method for Volatile Content of Coatings, (Approved June 1, 2015); IBR approved for appendix A-7 to part 60: Method 24, Section 6.2.

(96) ASTM D2382-76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(97) ASTM D2382-88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(98) ASTM D2504-67, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(99) ASTM D2504-77, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(100) ASTM D2504-88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g) and 60.485a(g).

(101) ASTM D2584-68(Reapproved 1985), Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).

(102) ASTM D2584-94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c).

(103) ASTM D2597-94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 60.335(b).

(104) ASTM D2622-87, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(105) ASTM D2622-94, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(106) ASTM D2622-98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j) and 60.335(b).

(107) ASTM D2622-05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a).

(108) ASTM D2879-83Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(109) ASTM D2879-96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(110) ASTM D2879-97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(111) ASTM D2880-78, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(112) ASTM D2880-96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(113) ASTM D2908-74, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(114) ASTM D2908-91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(115) ASTM D2986-71, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(116) ASTM D2986-78, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(117) ASTM D2986-95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(118) ASTM D3173-73, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(119) ASTM D3173-87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(120) ASTM D3176-74, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.

(121) ASTM D3176-89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.

(122) ASTM D3177-75, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(123) ASTM D3177-89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(124) ASTM D3178-73 (Reapproved 1979), Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f).

(125) ASTM D3178-89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f).

(126) ASTM D3246-81, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(127) ASTM D3246-92, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(128) ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b).

(129) ASTM D3246-05, Standard Test Method for Sulfur in Petrolum Gas by Oxidative Microcoulometry, IBR approved for § 60.4415(a)(1).

(130) ASTM D3270-73T, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(131) ASTM D3270-80, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(132) ASTM D3270-91, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(133) ASTM D3270-95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(134) ASTM D3286-85, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(135) ASTM D3286-96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(136) ASTM D3370-76, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(137) ASTM D3370-95a, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(138) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§ 60.107a(d), 60.5413(d), and 60.5413a(d).

(139) ASTM D3699-08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

(140) ASTM D3792-79, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.

(141) ASTM D3792-91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.

(142) ASTM D4017-81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(143) ASTM D4017-90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(144) ASTM D4017-96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(145) ASTM D4057-81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(146) ASTM D4057-95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(147) ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).

(148) ASTM D4084-82, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h).

(149) ASTM D4084-94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h).

(150) ASTM D4084-05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§ 60.4360 and 60.4415(a).

(151) ASTM D4177-95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(152) ASTM D4177-95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a).

(153) ASTM D4239-85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(154) ASTM D4239-94, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(155) ASTM D4239-97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(156) ASTM D4294-02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.335(b).

(157) ASTM D4294-03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a).

(158) ASTM D4442-84, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(159) ASTM D4442-92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(160) ASTM D4444-92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(161) ASTM D4457-85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.5.

(162) ASTM D4468-85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.335(b) and 60.4415(a).

(163) ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, (Approved June 1, 2006), IBR approved for § 60.107a(e).

(164) ASTM D4629-02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§ 60.49b(e) and 60.335(b).

(165) ASTM D4809-95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§ 60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(d), 60.664(e), and 60.704(d).

(166) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), (Approved December 1, 2006), IBR approved for § 60.107a(d).

(167) ASTM D4810-88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§ 60.4360 and 60.4415(a).

(168) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§ 60.107a(d), 60.5413(d), and 60.5413a(d).

(169) ASTM D5287-97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4415(a).

(170) ASTM D5403-93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for appendix A-7 to part 60: Method 24, Section 6.6.

(171) ASTM D5453-00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.335(b).

(172) ASTM D5453-05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.4415(a).

(173) ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 60.334(h) and 60.4360.

(174) ASTM D5504-08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, (Approved June 15, 2008), IBR approved for §§ 60.107a(e) and 60.5413(d).

(175) ASTM D5623-19, Standard Test Method for Sulfur Compounds in Light Petroleum Liquids by Gas Chromatography and Sulfur Selective Detection, (Approved July 1, 2019); IBR approved for § 60.4415(a).

(176) ASTM D5762-02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b).

(177) ASTM D5865-98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §§ 60.45(f) and 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(178) ASTM D5865-10, Standard Test Method for Gross Calorific Value of Coal and Coke, (Approved January 1, 2010), IBR approved for §§ 60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, section 12.5.2.1.3.

(179) ASTM D6216-12, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, approved October 1, 2012; IBR approved for appendix B to part 60.

(180) ASTM D6228-98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.334(h).

(181) ASTM D6228-98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§ 60.4360 and 60.4415.

(182) ASTM D6348-03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, (Approved October 1, 2003), IBR approved for § 60.73a(b), table 7 to subpart IIII, table 2 to subpart JJJJ, and § 60.4245(d).

(183) ASTM D6366-99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for § 60.335(b)(9).

(184) ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, (Approved October 1, 2004), IBR approved for § 60.107a(d) and table 2 to subpart JJJJ.

(185) ASTM D6522-00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 60.335(a).

(186) ASTM D6522-00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, (Approved October 1, 2005), IBR approved for table 2 to subpart JJJJ, §§ 60.5413(b) and (d), and 60.5413a(b).

(187) ASTM D6522-11 Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers (Approved December 1, 2011), IBR approved for § 60.37f(a), 60.766(a).

(188) ASTM D6667-01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.335(b).

(189) ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.4415(a).

(190) ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

(191) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for § 60.56c(b) and appendix B to part 60: Performance Specification 12A, Section 8.6.2.

(192) ASTM D6784-02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), (Approved April 1, 2008), IBR approved for §§ 60.2165(j) and 60.2730(j), tables 5, 6 and 8 to subpart CCCC, and tables 2, 6, 7, and 9 to subpart DDDD, §§ 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, and tables 2 and 3 to subpart MMMM.

(193) ASTM D6911-15, Standard Guide for Packaging and Shipping Environmental Samples for Laboratory Analysis, approved January 15, 2015, IBR approved for appendix A-8: Method 30B.

(194) ASTM D7039-15a, Standard Test Method for Sulfur in Gasoline, Diesel Fuel, Jet Fuel, Kerosine, Boideisel, Biodiesel Blends, and Gasoline-Ethanol Blends by Monochromatic Wavelength Dispersive X-ray Fluorescence Spectrometry, (Approved July 1, 2015); IBR approved for § 60.4415(a).

(195) ASTM D7467-10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, and 60.5580.

(196) ASTM D7520-16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, approved April 1, 2016; IBR approved for § 60.374a(d).

(197) ASTM E168-67, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(198) ASTM E168-77, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(199) ASTM E168-92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400, 60.5400a(f).

(200) ASTM E169-63, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f) .

(201) ASTM E169-77, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d), 60.593(b), and 60.593a(b), 60.632(f).

(202) ASTM E169-93, General Techniques of Ultraviolet Quantitative Analysis, (Approved May 15, 1993), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), and 60.5400a(f).

(203) ASTM E260-73, General Gas Chromatography Procedures, IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(204) ASTM E260-91, General Gas Chromatography Procedures, (IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(205) ASTM E260-96, General Gas Chromatography Procedures, (Approved April 10, 1996), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), 60.5400a(f) 60.5406(b), and 60.5406a(b)(3).

(206) ASTM E617-13, Standard Specification for Laboratory Weights and Precision Mass Standards, approved May 1, 2013, IBR approved for appendix A-3: Methods 4, 5, 5H, 5I, and appendix A-8: Method 29.

(207) ASTM E871-82 (Reapproved 2013), Standard Test Method for Moisture Analysis of Particulate Wood Fuels, (Approved August 15, 2013), IBR approved for appendix A-8: method 28R.

(208) ASTM E1584-11, Standard Test Method for Assay of Nitric Acid, (Approved August 1, 2011), IBR approved for § 60.73a(c).

(209) ASTM E2515-11, Standard Test Method for Determination of Particulate Matter Emissions Collected by a Dilution Tunnel, (Approved November 1, 2011), IBR approved for § 60.534 and § 60.5476.

(210) ASTM E2618-13 Standard Test Method for Measurement of Particulate Matter Emissions and Heating Efficiency of Outdoor Solid Fuel-Fired Hydronic Heating Appliances, (Approved September 1, 2013), IBR approved for § 60.5476.

(211) ASTM E2779-10, Standard Test Method for Determining Particulate Matter Emissions from Pellet Heaters, (Approved October 1, 2010), IBR approved for § 60.534.

(212) ASTM E2780-10, Standard Test Method for Determining Particulate Matter Emissions from Wood Heaters, (Approved October 1, 2010), IBR approved for appendix A: method 28R.

(213) ASTM UOP539-97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997), IBR approved for § 60.107a(d).

(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists (AOAC), 11th edition, 1970, pp. 11-12, IBR approved for §§ 60.204(b), 60.214(b), 60.224(b), and 60.234(b).

(2) [Reserved]

(j) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., Washington, DC 20460, (202) 272-0167, *http://www.epa.gov.*

(1) EPA-454/R-98-015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997, *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.PDF;* IBR approved for §§ 60.373a(b); 60.2145(r); 60.2710(r); 60.4905(b); 60.5225(b).

(2) EPA-600/R-12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, May 2012, IBR approved for §§ 60.5413(d) and 60.5413a(d).

(3) SW-846-6010D, Inductively Coupled Plasma-Optical Emission Spectrometry, Revision 5, July 2018, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for appendix A-5 to part 60: Method 12.

(4) SW-846-6020B, Inductively Coupled Plasma-Mass Spectrometry, Revision 2, July 2014, in EPA Publication No. SW-846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for appendix A-5 to part 60: Method 12.

(k) GPA Midstream Association (formerly known as Gas Processors Association), Sixty Sixty American Plaza, Suite 700, Tulsa, OK 74135.

Note 1 to paragraph (k):

Material in this paragraph that is no longer available from GPA may be available through the reseller HIS Markit, 15 Inverness Way East, P.O. Box 1154, Englewood, CO 80150-1154, *https://global.ihs.com/*. For material that is out-of-print, contact EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave. NW, Washington, DC 20460 or *a-and-rdocket@epa.gov.*

(1) GPA Midstream Standard 2140-17 (GPA 2140-17), Liquefied Petroleum Gas Specifications and Test Methods, (Revised 2017), IBR approved for § 60.4415(a).

(2) GPA Midstream Standard 2166-17 (GPA 2166-17), Obtaining Natural Gas Samples for Analysis by Gas Chromatography, (Reaffirmed 2017), IBR approved for § 60.4415(a).

(3) Gas Processors Association Standard 2172-09, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009), IBR approved for § 60.107a(d).

(4) GPA Standard 2174-14 (GPA 2174-14), Obtaining Liquid Hydrocarbon Samples for Analysis by Gas Chromatography, (Revised 2014), IBR approved for § 60.4415(a).

(5) GPA Standard 2261-19 (GPA 2261-19), Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, (Revised 2019), IBR approved for § 60.4415(a).

(6) Gas Processors Association Standard 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision, IBR approved for §§ 60.105(b), 60.107a(b), 60.334(h), 60.4360, and 60.4415(a).

(l) International Organization for Standardization (ISO) available through IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) ISO 8178-4: 1996(E), Reciprocating Internal Combustion Engines - Exhaust Emission Measurement - part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) ISO 10715:1997(E), Natural gas - Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a)

(m) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, + 41 22 749 01 11, *http://www.iso.org/iso/home.htm.*

(1) ISO 2314:2009(E), Gas turbines-Acceptance tests, Third edition (December 15, 2009), IBR approved for § 60.5580.

(2) ISO 8316: Measurement of Liquid Flow in Closed Conduits - Method by Collection of the Liquid in a Volumetric Tank (1987-10-01) - First Edition, IBR approved for § 60.107a(d).

(n) This material is available for purchase from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-125), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) OMB Bulletin No. 93-17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93-192-664. IBR approved for § 60.31e.

(2) [Reserved]

(o) North American Electric Reliability Corporation, 1325 G Street NW., Suite 600, Washington, DC 20005-3801, *http://www.nerc.com.*

(1) North American Electric Reliability Corporation Reliability Standard EOP-002-3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for §§ 60.4211(f) and 60.4243(d). Also available online: *http://www.nerc.com/files/EOP-002-3__1.pdf.*

(2) [Reserved]

(p) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092, Telephone (800) 332-8686, and is also available at the following Web site: *http://www.tappi.org*.

(1) TAPPI Method T 624 cm-11, (Copyright 2011), IBR approved, for §§ 60.285(d) and 60.285a(d).

(2) [Reserved]

(q) Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance, IBR approved for appendix A-8 to part 60.

(2) [Reserved]

(r) Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103-105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved for § 60.683(b).

(2) [Reserved]

(s) West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5-21, 90 and 91, September 3, 1970, revised 1984, IBR approved for appendix A-8 to part 60.

(2) [Reserved]

(t) This material is available for purchase from the Canadian Standards Association (CSA), 5060 Spectrum Way, Suite 100, Mississauga, Ontario, Canada L4W 5N6, Telephone: 800-463-6727.

(1) CSA B415.1-10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for § 60.534 and § 60.5476. (The standard is also available at *http://shop.csa.ca/en/canada/fuel-burning-equipment/b4151-10/invt/27013322010*)

(2) [Reserved]

(u) This European National (EN) standards material is available for purchase at European Committee for Standardization, Management Centre, Avenue Marnix 17, B-1000 Brussels, Belgium, Telephone: + 32 2 550 08 11.

(1) DIN EN 303-5:2012E (EN 303-5), Heating boilers - Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW - Terminology, requirements, testing and marking, (October 2012), IBR approved for § 60.5476. (The standard is also available at *http://www.en-standard.eu/csn-en-303-5-heating-boilers-part-5-heating-boilers-for-solid-fuels-manually-and-automatically-stoked-nominal-heat-output-of-up-to-500-kw-terminology-requirements-testing-and-marking/?gclid=CJXI2P__97MMCFdccgQodan8ATA*)

(2) [Reserved]

§ 60.18 General control device and work practice requirements.

(a) ***Introduction.***

(1) This section contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(2) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(b) ***Flares.*** Paragraphs (c) through (f) apply to flares.

(c) (1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i) (A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max}, as determined by the following equation:

$V_{max} = (X_{H2} - K_1) * K_2$

Where:

V_{max} = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4) (i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f) (1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant}, \; 1.740 \times 10^{-7} \left(\frac{1}{ppm}\right) \left(\frac{g\ mole}{scm}\right) \left(\frac{MJ}{kcal}\right)$$

where the standard temperature for $\left(\frac{g\ mole}{scm}\right)$ is 20°C;

C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in § 60.17); and

H_i = Net heat of combustion of sample component i, kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$Log_{10} (V_{max}) = (H_T + 28.8)/31.7$

V_{max} = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$V_{max} = 8.706 + 0.7084 (H_T)$

V_{max} = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(g) ***Alternative work practice for monitoring equipment for leaks.*** Paragraphs (g), (h), and (i) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, appendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (g), (h), and (i) of this section apply to this standard. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (g)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (g), (h), and (i) of this section.

(1) ***Applicable subpart*** means the subpart in 40 CFR parts 60, 61, 63, or 65 that requires monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(2) ***Equipment*** means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(3) ***Imaging*** means making visible emissions that may otherwise be invisible to the naked eye.

(4) ***Optical gas imaging instrument*** means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.

(5) ***Repair*** means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.

(6) ***Leak*** means:

(i) Any emissions imaged by the optical gas instrument;

(ii) Indications of liquids dripping;

(iii) Indications by a sensor that a seal or barrier fluid system has failed; or

(iv) Screening results using a 40 CFR part 60, appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(h) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(1) An owner or operator of an affected source subject to CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (i) of this section instead of using the 40 CFR part 60, appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.

(2) Any leak detected when following the leak survey procedure in paragraph (i)(3) of this section must be identified for repair as required in the applicable subpart.

(3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart to which the equipment is subject.

(4) The schedule for repair is as required in the applicable subpart.

(5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.

(6) When this alternative work practice is used for detecting leaking equipment the following are not applicable for the equipment being monitored:

(i) Skip period leak detection and repair;

(ii) Quality improvement plans; or

(iii) Complying with standards for allowable percentage of valves and pumps to leak.

(7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (h)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, appendix

A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.

(i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.

(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.

(i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.

(A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from the stream identified in paragraph (i)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

$$E_{dic} = (E_{sds}) \sum_{i=1}^{k} x_i$$

Where:

E_{dic} = Mass flow rate for the daily instrument check, grams per hour

x_i = Mass fraction of detectable chemical(s) i seen by the optical gas imaging instrument, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level, E_{sds}.

E_{sds} = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

k = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under § 60.13(i).

(3) Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. You must keep the records described in paragraphs (i)(4)(i) through (i)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.

(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (i)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (i)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subpart.

(5) Reporting. Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to *CCG-AWP@EPA.GOV.*

§ 60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word “calendar” is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such

facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

Table 1 to Subpart A of Part 60 - Detection Sensitivity Levels (grams per hour)

Monitoring frequency per subpart[a]	Detection sensitivity level
Bi-Monthly	60

Monitoring frequency per subpart[a]	Detection sensitivity level
Semi-Quarterly	85
Monthly	100

[a] When this alternative work practice is used to identify leaking equipment, the owner or operator must choose one of the monitoring frequencies listed in this table in lieu of the monitoring frequency specified in the applicable subpart. Bi-monthly means every other month. Semi-quarterly means twice per quarter. Monthly means once per month.

Appendix D. 40 CFR Part 63, Subpart A—General Provisions

§ 63.1 Applicability.

(a) *General.*

(1) Terms used throughout this part are defined in § 63.2 or in the Clean Air Act (Act) as amended in 1990, except that individual subparts of this part may include specific definitions in addition to or that supersede definitions in § 63.2.

(2) This part contains national emission standards for hazardous air pollutants (NESHAP) established pursuant to section 112 of the Act as amended November 15, 1990. These standards regulate specific categories of stationary sources that emit (or have the potential to emit) one or more hazardous air pollutants listed in this part pursuant to section 112(b) of the Act. This section explains the applicability of such standards to sources affected by them. The standards in this part are independent of NESHAP contained in 40 CFR part 61. The NESHAP in part 61 promulgated by signature of the Administrator before November 15, 1990 (i.e., the date of enactment of the Clean Air Act Amendments of 1990) remain in effect until they are amended, if appropriate, and added to this part.

(3) No emission standard or other requirement established under this part shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established by the Administrator pursuant to other authority of the Act (section 111, part C or D or any other authority of this Act), or a standard issued under State authority. The Administrator may specify in a specific standard under this part that facilities subject to other provisions under the Act need only comply with the provisions of that standard.

(4) (i) Each relevant standard in this part 63 must identify explicitly whether each provision in this subpart A is or is not included in such relevant standard.

(ii) If a relevant part 63 standard incorporates the requirements of 40 CFR part 60, part 61 or other part 63 standards, the relevant part 63 standard must identify explicitly the applicability of each corresponding part 60, part 61, or other part 63 subpart A (General) provision.

(iii) The General Provisions in this subpart A do not apply to regulations developed pursuant to section 112(r) of the amended Act, unless otherwise specified in those regulations.

(5) [Reserved]

(6) To obtain the most current list of categories of sources to be regulated under section 112 of the Act, or to obtain the most recent regulation promulgation schedule established pursuant to section 112(e) of the Act, contact the Office of the Director, Emission Standards Division, Office of Air Quality Planning and Standards, U.S. EPA (MD-13), Research Triangle Park, North Carolina 27711.

(7)-(9) [Reserved]

(10) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word “calendar” is absent, unless otherwise specified in an applicable requirement.

(11) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, test plan, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be

submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery agreed to by the permitting authority, is acceptable.

(12) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in § 63.9(i).

(b) *Initial applicability determination for this part.*

(1) The provisions of this part apply to the owner or operator of any stationary source that -

(i) Emits or has the potential to emit any hazardous air pollutant listed in or pursuant to section 112(b) of the Act; and

(ii) Is subject to any standard, limitation, prohibition, or other federally enforceable requirement established pursuant to this part.

(2) [Reserved]

(3) An owner or operator of a stationary source who is in the relevant source category and who determines that the source is not subject to a relevant standard or other requirement established under this part must keep a record as specified in § 63.10(b)(3).

(c) *Applicability of this part after a relevant standard has been set under this part.*

(1) If a relevant standard has been established under this part, the owner or operator of an affected source must comply with the provisions of that standard and of this subpart as provided in paragraph (a)(4) of this section.

(2) Except as provided in § 63.10(b)(3), if a relevant standard has been established under this part, the owner or operator of an affected source may be required to obtain a title V permit from a permitting authority in the State in which the source is located. Emission standards promulgated in this part for area sources pursuant to section 112(c)(3) of the Act will specify whether -

(i) States will have the option to exclude area sources affected by that standard from the requirement to obtain a title V permit (i.e., the standard will exempt the category of area sources altogether from the permitting requirement);

(ii) States will have the option to defer permitting of area sources in that category until the Administrator takes rulemaking action to determine applicability of the permitting requirements; or

(iii) If a standard fails to specify what the permitting requirements will be for area sources affected by such a standard, then area sources that are subject to the standard will be subject to the requirement to obtain a title V permit without any deferral.

(3)-(4) [Reserved]

(5) If an area source that otherwise would be subject to an emission standard or other requirement established under this part if it were a major source subsequently increases its emissions of hazardous air pollutants (or its potential to emit hazardous air pollutants) such that the source is a major source that is subject to the emission standard or other requirement, such source also shall be subject to the notification requirements of this subpart.

(6) A major source may become an area source at any time upon reducing its emissions of and potential to emit hazardous air pollutants, as defined in this subpart, to below the major source thresholds established in § 63.2, subject to the provisions in paragraphs (c)(6)(i) and (ii) of this section.

(i) A major source reclassifying to area source status is subject to the applicability of standards, compliance dates and notification requirements specified in (c)(6)(i)(A) of this section. An area source that previously was a major source and becomes a major source again is subject to the applicability of standards, compliance dates, and notification requirements specified in (c)(6)(i)(B) of this section:

(A) A major source reclassifying to area source status under this part remains subject to any applicable major source requirements established under this part until the reclassification becomes effective. After the reclassification becomes effective, the source is subject to any applicable area source requirements established under this part immediately, provided the compliance date for the area source requirements has passed. The owner or operator of a major source that becomes an area source subject to newly applicable area source requirements under this part must comply with the initial notification requirements pursuant to § 63.9(b). The owner or operator of a major source that becomes an area source must also provide to the Administrator any change in the information already provided under § 63.9(b) per § 63.9(j).

(B) An area source that previously was a major source under this part and that becomes a major source again is subject to the applicable major source requirements established under this part immediately upon becoming a major source again, provided the compliance date for the major source requirements has passed, notwithstanding any provision within the applicable subparts. The owner or operator of an area source that becomes a major source again must comply with the initial notification pursuant to § 63.9(b). The owner or operator must also provide to the Administrator any change in the information already provided under § 63.9(b) per § 63.9(j).

(ii) Becoming an area source does not absolve a source subject to an enforcement action or investigation for major source violations or infractions from the consequences of any actions occurring when the source was major. Becoming a major source does not absolve a source subject to an enforcement action or investigation for area source violations or infractions from the consequences of any actions occurring when the source was an area source.

(d) [Reserved]

(e) If the Administrator promulgates an emission standard under section 112(d) or (h) of the Act that is applicable to a source subject to an emission limitation by permit established under section 112(j) of the Act, and the requirements under the section 112(j) emission limitation are substantially as effective as the promulgated emission standard, the owner or operator may request the permitting authority to revise the source's title V permit to reflect that the emission limitation in the permit satisfies the requirements of the promulgated emission standard. The process by which the permitting authority determines whether the section 112(j) emission limitation is substantially as effective as the promulgated emission standard must include, consistent with part 70 or 71 of this chapter, the opportunity for full public, EPA, and affected State review (including the opportunity for EPA's objection) prior to the permit revision being finalized. A negative determination by the permitting authority constitutes final action for purposes of review and appeal under the applicable title V operating permit program.

§ 63.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Pub. L. 101-549, 104 Stat. 2399).

Actual emissions is defined in subpart D of this part for the purpose of granting a compliance extension for an early reduction of hazardous air pollutants.

Administrator means the Administrator of the United States Environmental Protection Agency or his or her authorized representative (e.g., a State that has been delegated the authority to implement the provisions of this part).

Affected source, for the purposes of this part, means the collection of equipment, activities, or both within a single contiguous area and under common control that is included in a section 112(c) source category or subcategory for which a section 112(d) standard or other relevant standard is established pursuant to section 112 of the Act. Each relevant standard will define the “affected source,” as defined in this paragraph unless a different definition is warranted based on a published justification as to why this definition would result in significant administrative, practical, or implementation problems and why the different definition would resolve those problems. The term “affected source,” as used in this part, is separate and distinct from any other use of that term in EPA regulations such as those implementing title IV of the Act. Affected source may be defined differently for part 63 than affected facility and stationary source in parts 60 and 61, respectively. This definition of “affected source,” and the procedures for adopting an alternative definition of “affected source,” shall apply to each section 112(d) standard for which the initial proposed rule is signed by the Administrator after June 30, 2002.

Alternative emission limitation means conditions established pursuant to sections 112(i)(5) or 112(i)(6) of the Act by the Administrator or by a State with an approved permit program.

Alternative emission standard means an alternative means of emission limitation that, after notice and opportunity for public comment, has been demonstrated by an owner or operator to the Administrator's satisfaction to achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such pollutant achieved under a relevant design, equipment, work practice, or operational emission standard, or combination thereof, established under this part pursuant to section 112(h) of the Act.

Alternative test method means any method of sampling and analyzing for an air pollutant that has been demonstrated to the Administrator's satisfaction, using Method 301 in appendix A of this part, to produce

results adequate for the Administrator's determination that it may be used in place of a test method specified in this part.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to title V of the Act (42 U.S.C. 7661).

Area source means any stationary source of hazardous air pollutants that is not a major source as defined in this part.

Commenced means, with respect to construction or reconstruction of an affected source, that an owner or operator has undertaken a continuous program of construction or reconstruction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or reconstruction.

Compliance date means the date by which an affected source is required to be in compliance with a relevant standard, limitation, prohibition, or any federally enforceable requirement established by the Administrator (or a State with an approved permit program) pursuant to section 112 of the Act.

Compliance schedule means:

(1) In the case of an affected source that is in compliance with all applicable requirements established under this part, a statement that the source will continue to comply with such requirements; or

(2) In the case of an affected source that is required to comply with applicable requirements by a future date, a statement that the source will meet such requirements on a timely basis and, if required by an applicable requirement, a detailed schedule of the dates by which each step toward compliance will be reached; or

(3) In the case of an affected source not in compliance with all applicable requirements established under this part, a schedule of remedial measures, including an enforceable sequence of actions or operations with milestones and a schedule for the submission of certified progress reports, where applicable, leading to compliance with a relevant standard, limitation, prohibition, or any federally enforceable requirement established pursuant to section 112 of the Act for which the affected source is not in compliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.

Construction means the on-site fabrication, erection, or installation of an affected source. Construction does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location. The owner or operator of an existing affected source that is relocated may elect not to reinstall minor ancillary equipment including, but not limited to, piping, ductwork, and valves. However, removal and reinstallation of an affected source will be construed as reconstruction if it satisfies the criteria for reconstruction as defined in this section. The costs of replacing minor ancillary equipment must be considered in determining whether the existing affected source is reconstructed.

Continuous emission monitoring system (CEMS) means the total equipment that may be required to meet the data acquisition and availability requirements of this part, used to sample, condition (if applicable), analyze, and provide a record of emissions.

Continuous monitoring system (CMS) is a comprehensive term that may include, but is not limited to, continuous emission monitoring systems, continuous opacity monitoring systems, continuous parameter monitoring systems, or other manual or automatic monitoring that is used for demonstrating compliance with an applicable regulation on a continuous basis as defined by the regulation.

Continuous opacity monitoring system (COMS) means a continuous monitoring system that measures the opacity of emissions.

Continuous parameter monitoring system means the total equipment that may be required to meet the data acquisition and availability requirements of this part, used to sample, condition (if applicable), analyze, and provide a record of process or control system parameters.

Effective date means:

(1) With regard to an emission standard established under this part, the date of promulgation in the Federal Register of such standard; or

(2) With regard to an alternative emission limitation or equivalent emission limitation determined by the Administrator (or a State with an approved permit program), the date that the alternative emission limitation or equivalent emission limitation becomes effective according to the provisions of this part.

Emission standard means a national standard, limitation, prohibition, or other regulation promulgated in a subpart of this part pursuant to sections 112(d), 112(h), or 112(f) of the Act.

Emissions averaging is a way to comply with the emission limitations specified in a relevant standard, whereby an affected source, if allowed under a subpart of this part, may create emission credits by reducing emissions from specific points to a level below that required by the relevant standard, and those credits are used to offset emissions from points that are not controlled to the level required by the relevant standard.

EPA means the United States Environmental Protection Agency.

Equivalent emission limitation means any maximum achievable control technology emission limitation or requirements which are applicable to a major source of hazardous air pollutants and are adopted by the Administrator (or a State with an approved permit program) on a case-by-case basis, pursuant to section 112(g) or (j) of the Act.

Excess emissions and continuous monitoring system performance report is a report that must be submitted periodically by an affected source in order to provide data on its compliance with relevant emission limits, operating parameters, and the performance of its continuous parameter monitoring systems.

Existing source means any affected source that is not a new source.

Federally enforceable means all limitations and conditions that are enforceable by the Administrator and citizens under the Act or that are enforceable under other statutes administered by the Administrator. Examples of federally enforceable limitations and conditions include, but are not limited to:

(1) Emission standards, alternative emission standards, alternative emission limitations, and equivalent emission limitations established pursuant to section 112 of the Act as amended in 1990;

(2) New source performance standards established pursuant to section 111 of the Act, and emission standards established pursuant to section 112 of the Act before it was amended in 1990;

(3) All terms and conditions in a title V permit, including any provisions that limit a source's potential to emit, unless expressly designated as not federally enforceable;

(4) Limitations and conditions that are part of an approved State Implementation Plan (SIP) or a Federal Implementation Plan (FIP);

(5) Limitations and conditions that are part of a Federal construction permit issued under 40 CFR 52.21 or any construction permit issued under regulations approved by the EPA in accordance with 40 CFR part 51;

(6) Limitations and conditions that are part of an operating permit where the permit and the permitting program pursuant to which it was issued meet all of the following criteria:

(i) The operating permit program has been submitted to and approved by EPA into a State implementation plan (SIP) under section 110 of the CAA;

(ii) The SIP imposes a legal obligation that operating permit holders adhere to the terms and limitations of such permits and provides that permits which do not conform to the operating permit program requirements and the requirements of EPA's underlying regulations may be deemed not “federally enforceable” by EPA;

(iii) The operating permit program requires that all emission limitations, controls, and other requirements imposed by such permits will be at least as stringent as any other applicable limitations and requirements contained in the SIP or enforceable under the SIP, and that the program may not issue permits that waive, or make less stringent, any limitations or requirements contained in or issued pursuant to the SIP, or that are otherwise “federally enforceable”;

(iv) The limitations, controls, and requirements in the permit in question are permanent, quantifiable, and otherwise enforceable as a practical matter; and

(v) The permit in question was issued only after adequate and timely notice and opportunity for comment for EPA and the public.

(7) Limitations and conditions in a State rule or program that has been approved by the EPA under subpart E of this part for the purposes of implementing and enforcing section 112; and

(8) Individual consent agreements that the EPA has legal authority to create.

Fixed capital cost means the capital needed to provide all the depreciable components of an existing source.

Force majeure means, for purposes of § 63.7, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Fugitive emissions means those emissions from a stationary source that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Under section 112 of the Act, all fugitive emissions are to be considered in determining whether a stationary source is a major source.

Hazardous air pollutant means any air pollutant listed in or pursuant to section 112(b) of the Act.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is

the permitting authority, issuance of a title V permit occurs immediately after the EPA takes final action on the final permit.

Major source means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants, unless the Administrator establishes a lesser quantity, or in the case of radionuclides, different criteria from those specified in this sentence.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Monitoring means the collection and use of measurement data or other information to control the operation of a process or pollution control device or to verify a work practice standard relative to assuring compliance with applicable requirements. Monitoring is composed of four elements:

(1) Indicator(s) of performance - the parameter or parameters you measure or observe for demonstrating proper operation of the pollution control measures or compliance with the applicable emissions limitation or standard. Indicators of performance may include direct or predicted emissions measurements (including opacity), operational parametric values that correspond to process or control device (and capture system) efficiencies or emissions rates, and recorded findings of inspection of work practice activities, materials tracking, or design characteristics. Indicators may be expressed as a single maximum or minimum value, a function of process variables (for example, within a range of pressure drops), a particular operational or work practice status (for example, a damper position, completion of a waste recovery task, materials tracking), or an interdependency between two or among more than two variables.

(2) Measurement techniques - the means by which you gather and record information of or about the indicators of performance. The components of the measurement technique include the detector type, location and installation specifications, inspection procedures, and quality assurance and quality control measures. Examples of measurement techniques include continuous emission monitoring systems, continuous opacity monitoring systems, continuous parametric monitoring systems, and manual inspections that include making records of process conditions or work practices.

(3) Monitoring frequency - the number of times you obtain and record monitoring data over a specified time interval. Examples of monitoring frequencies include at least four points equally spaced for each hour for continuous emissions or parametric monitoring systems, at least every 10 seconds for continuous opacity monitoring systems, and at least once per operating day (or week, month, etc.) for work practice or design inspections.

(4) Averaging time - the period over which you average and use data to verify proper operation of the pollution control approach or compliance with the emissions limitation or standard. Examples of averaging time include a 3-hour average in units of the emissions limitation, a 30-day rolling average emissions value, a daily average of a control device operational parametric range, and an instantaneous alarm.

New affected source means the collection of equipment, activities, or both within a single contiguous area and under common control that is included in a section 112(c) source category or subcategory that is subject to a section 112(d) or other relevant standard for new sources. This definition of “new affected source,” and the

criteria to be utilized in implementing it, shall apply to each section 112(d) standard for which the initial proposed rule is signed by the Administrator after June 30, 2002. Each relevant standard will define the term "new affected source," which will be the same as the "affected source" unless a different collection is warranted based on consideration of factors including:

(1) Emission reduction impacts of controlling individual sources versus groups of sources;

(2) Cost effectiveness of controlling individual equipment;

(3) Flexibility to accommodate common control strategies;

(4) Cost/benefits of emissions averaging;

(5) Incentives for pollution prevention;

(6) Feasibility and cost of controlling processes that share common equipment (e.g., product recovery devices);

(7) Feasibility and cost of monitoring; and

(8) Other relevant factors.

New source means any affected source the construction or reconstruction of which is commenced after the Administrator first proposes a relevant emission standard under this part establishing an emission standard applicable to such source.

One-hour period, unless otherwise defined in an applicable subpart, means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background. For continuous opacity monitoring systems, opacity means the fraction of incident light that is attenuated by an optical medium.

Owner or operator means any person who owns, leases, operates, controls, or supervises a stationary source.

Performance audit means a procedure to analyze blind samples, the content of which is known by the Administrator, simultaneously with the analysis of performance test samples in order to provide a measure of test data quality.

Performance evaluation means the conduct of relative accuracy testing, calibration error testing, and other measurements used in validating the continuous monitoring system data.

Performance test means the collection of data resulting from the execution of a test method (usually three emission test runs) used to demonstrate compliance with a relevant emission standard as specified in the performance test section of the relevant standard.

Permit modification means a change to a title V permit as defined in regulations codified in this chapter to implement title V of the Act (42 U.S.C. 7661).

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permit revision means any permit modification or administrative permit amendment to a title V permit as defined in regulations codified in this chapter to implement title V of the Act (42 U.S.C. 7661).

Permitting authority means:

(1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or

(2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Pollution Prevention means *source reduction* as defined under the Pollution Prevention Act (42 U.S.C. 13101-13109). The definition is as follows:

(1) *Source reduction* is any practice that:

(i) Reduces the amount of any hazardous substance, pollutant, or contaminant entering any waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment, or disposal; and

(ii) Reduces the hazards to public health and the environment associated with the release of such substances, pollutants, or contaminants.

(2) The term *source reduction* includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control.

(3) The term *source reduction* does not include any practice that alters the physical, chemical, or biological characteristics or the volume of a hazardous substance, pollutant, or contaminant through a process or activity which itself is not integral to and necessary for the production of a product or the providing of a service.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is enforceable.

Reconstruction, unless otherwise defined in a relevant standard, means the replacement of components of an affected or a previously nonaffected source to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source; and

(2) It is technologically and economically feasible for the reconstructed source to meet the relevant standard(s) established by the Administrator (or a State) pursuant to section 112 of the Act. Upon reconstruction, an affected source, or a stationary source that becomes an affected source, is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source.

Regulation promulgation schedule means the schedule for the promulgation of emission standards under this part, established by the Administrator pursuant to section 112(e) of the Act and published in the Federal Register.

Relevant standard means:

(1) An emission standard;

(2) An alternative emission standard;

(3) An alternative emission limitation; or

(4) An equivalent emission limitation established pursuant to section 112 of the Act that applies to the collection of equipment, activities, or both regulated by such standard or limitation. A relevant standard may include or consist of a design, equipment, work practice, or operational requirement, or other measure, process, method, system, or technique (including prohibition of emissions) that the Administrator (or a State) establishes for new or existing sources to which such standard or limitation applies. Every relevant standard established pursuant to section 112 of the Act includes subpart A of this part, as provided by § 63.1(a)(4), and all applicable appendices of this part or of other parts of this chapter that are referenced in that standard.

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representative is approved in advance by the Administrator.

(2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively.

(3) For a municipality, State, Federal, or other public agency: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of the EPA).

(4) For affected sources (as defined in this part) applying for or subject to a title V permit: “responsible official” shall have the same meaning as defined in part 70 or Federal title V regulations in this chapter (42 U.S.C. 7661), whichever is applicable.

Run means one of a series of emission or other measurements needed to determine emissions for a representative operating period or cycle as specified in this part.

Shutdown means the cessation of operation of an affected source or portion of an affected source for any purpose.

Six-minute period means, with respect to opacity determinations, any one of the 10 equal parts of a 1-hour period.

Source at a Performance Track member facility means a major or area source located at a facility which has been accepted by EPA for membership in the Performance Track Program (as described at *www.epa.gov/PerformanceTrack*) and is still a member of the Program. The Performance Track Program is a voluntary program that encourages continuous environmental improvement through the use of environmental management systems, local community outreach, and measurable results.

Standard conditions means a temperature of 293 K (68 °F) and a pressure of 101.3 kilopascals (29.92 in. Hg).

Startup means the setting in operation of an affected source or portion of an affected source for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement:

(1) The provisions of this part and/or

(2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Test method means the validated procedure for sampling, preparing, and analyzing for an air pollutant specified in a relevant standard as the performance test procedure. The test method may include methods described in an appendix of this chapter, test methods incorporated by reference in this part, or methods validated for an application through procedures in Method 301 of appendix A of this part.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Visible emission means the observation of an emission of opacity or optical density above the threshold of vision.

Working day means any day on which Federal Government offices (or State government offices for a State that has obtained delegation under section 112(l)) are open for normal business. Saturdays, Sundays, and official Federal (or where delegated, State) holidays are not working days.

§ 63.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) *System International (SI) units of measure:*

A = ampere

g = gram

Hz = hertz

J = joule

°K = degree Kelvin

kg = kilogram

l = liter

m = meter

m^3 = cubic meter

mg = milligram = 10^{-3} gram

ml = milliliter = 10^{-3} liter

mm = millimeter = 10^{-3} meter

Mg = megagram = 10^{6} gram = metric ton

MJ = megajoule

mol = mole

N = newton

ng = nanogram = 10^{-9} gram

nm = nanometer = 10^{-9} meter

Pa = pascal

s = second

V = volt

W = watt

Ω = ohm

µg = microgram = 10^{-6} gram

µl = microliter = 10^{-6} liter

(b) *Other units of measure:*

Btu = British thermal unit

°C = degree Celsius (centigrade)

cal = calorie

cfm = cubic feet per minute

cc = cubic centimeter

cu ft = cubic feet

d = day

dcf = dry cubic feet

dcm = dry cubic meter

dscf = dry cubic feet at standard conditions

dscm = dry cubic meter at standard conditions

eq = equivalent

°F degree Fahrenheit

ft = feet

ft^2 = square feet

ft^3 = cubic feet

gal = gallon

gr = grain

g-eq = gram equivalent

g-mole = gram mole

hr = hour

in. = inch

in. H_2O = inches of water

K = 1,000

kcal = kilocalorie

lb = pound

lpm = liter per minute

meq = milliequivalent

min = minute

MW = molecular weight

oz = ounces

ppb = parts per billion

ppbw = parts per billion by weight

ppbv = parts per billion by volume

ppm = parts per million

ppmw = parts per million by weight

ppmv = parts per million by volume

psia = pounds per square inch absolute

psig = pounds per square inch gage

°R = degree Rankine

scf = cubic feet at standard conditions

scfh = cubic feet at standard conditions per hour

scm = cubic meter at standard conditions

scmm = cubic meter at standard conditions per minute

sec = second

sq ft = square feet

std = at standard conditions

v/v = volume per volume

yd^2 = square yards

yr = year

(c) *Miscellaneous:*

act = actual

avg = average

I.D. = inside diameter

M = molar

N = normal

O.D. = outside diameter

% = percent

§ 63.4 Prohibited activities and circumvention.

(a) *Prohibited activities.*

(1) No owner or operator subject to the provisions of this part must operate any affected source in violation of the requirements of this part. Affected sources subject to and in compliance with either an extension of compliance or an exemption from compliance are not in violation of the requirements of this part. An extension of compliance can be granted by the Administrator under this part; by a State with an approved permit program; or by the President under section 112(i)(4) of the Act.

(2) No owner or operator subject to the provisions of this part shall fail to keep records, notify, report, or revise reports as required under this part.

(3)-(5) [Reserved]

(b) *Circumvention.* No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment, or process to conceal an emission that would otherwise constitute noncompliance with a relevant standard. Such concealment includes, but is not limited to -

(1) The use of diluents to achieve compliance with a relevant standard based on the concentration of a pollutant in the effluent discharged to the atmosphere;

(2) The use of gaseous diluents to achieve compliance with a relevant standard for visible emissions; and

(c) *Fragmentation.* Fragmentation after November 15, 1990 which divides ownership of an operation, within the same facility among various owners where there is no real change in control, will not affect applicability. The owner and operator must not use fragmentation or phasing of reconstruction activities (i.e., intentionally dividing reconstruction into multiple parts for purposes of avoiding new source requirements) to avoid becoming subject to new source requirements.

§ 63.5 Preconstruction review and notification requirements.

(a) *Applicability.*

(1) This section implements the preconstruction review requirements of section 112(i)(1). After the effective date of a relevant standard, promulgated pursuant to section 112(d), (f), or (h) of the Act, under this part, the preconstruction review requirements in this section apply to the owner or operator of new affected sources and reconstructed affected sources that are major-emitting as specified in this section. New and reconstructed affected sources that commence construction or reconstruction before the effective date of a relevant standard are not subject to the preconstruction review requirements specified in paragraphs (b)(3), (d), and (e) of this section.

(2) This section includes notification requirements for new affected sources and reconstructed affected sources that are not major-emitting affected sources and that are or become subject to a relevant promulgated emission standard after the effective date of a relevant standard promulgated under this part.

(b) *Requirements for existing, newly constructed, and reconstructed sources.*

(1) A new affected source for which construction commences after proposal of a relevant standard is subject to relevant standards for new affected sources, including compliance dates. An affected source for which reconstruction commences after proposal of a relevant standard is subject to relevant standards for new sources, including compliance dates, irrespective of any change in emissions of hazardous air pollutants from that source.

(2) [Reserved]

(3) After the effective date of any relevant standard promulgated by the Administrator under this part, no person may, without obtaining written approval in advance from the Administrator in accordance with the procedures specified in paragraphs (d) and (e) of this section, do any of the following:

(i) Construct a new affected source that is major-emitting and subject to such standard;

(ii) Reconstruct an affected source that is major-emitting and subject to such standard; or

(iii) Reconstruct a major source such that the source becomes an affected source that is major-emitting and subject to the standard.

(4) After the effective date of any relevant standard promulgated by the Administrator under this part, an owner or operator who constructs a new affected source that is not major-emitting or reconstructs an affected source that is not major-emitting that is subject to such standard, or reconstructs a source such that the source becomes an affected source subject to the standard, must notify the Administrator of the intended construction or reconstruction. The notification must be submitted in accordance with the procedures in § 63.9(b).

(5) [Reserved]

(6) After the effective date of any relevant standard promulgated by the Administrator under this part, equipment added (or a process change) to an affected source that is within the scope of the definition of affected source under the relevant standard must be considered part of the affected source and subject to all provisions of the relevant standard established for that affected source.

(c) [Reserved]

(d) *Application for approval of construction or reconstruction.* The provisions of this paragraph implement section 112(i)(1) of the Act.

(1) *General application requirements.*

(i) An owner or operator who is subject to the requirements of paragraph (b)(3) of this section must submit to the Administrator an application for approval of the construction or reconstruction. The application must be submitted as soon as practicable before actual construction or reconstruction begins. The application for approval of construction or reconstruction may be used to fulfill the initial notification requirements of § 63.9(b)(5). The owner or operator may submit the application for approval well in advance of the date actual construction or reconstruction begins in order to ensure a timely review by the Administrator and that the planned date to begin will not be delayed.

(ii) A separate application shall be submitted for each construction or reconstruction. Each application for approval of construction or reconstruction shall include at a minimum:

(A) The applicant's name and address;

(B) A notification of intention to construct a new major affected source or make any physical or operational change to a major affected source that may meet or has been determined to meet the criteria for a reconstruction, as defined in § 63.2 or in the relevant standard;

(C) The address (i.e., physical location) or proposed address of the source;

(D) An identification of the relevant standard that is the basis of the application;

(E) The expected date of the beginning of actual construction or reconstruction;

(F) The expected completion date of the construction or reconstruction;

(G) [Reserved]

(H) The type and quantity of hazardous air pollutants emitted by the source, reported in units and averaging times and in accordance with the test methods specified in the relevant standard, or if actual emissions data are not yet available, an estimate of the type and quantity of hazardous air pollutants expected to be emitted by the source reported in units and averaging times specified in the relevant standard. The owner or operator may submit percent reduction information if a relevant standard is established in terms of percent reduction. However, operating parameters, such as flow rate, shall be included in the submission to the extent that they demonstrate performance and compliance; and

(I) [Reserved]

(J) Other information as specified in paragraphs (d)(2) and (d)(3) of this section.

(iii) An owner or operator who submits estimates or preliminary information in place of the actual emissions data and analysis required in paragraphs (d)(1)(ii)(H) and (d)(2) of this section shall submit the actual, measured emissions data and other correct information as soon as

available but no later than with the notification of compliance status required in § 63.9(h) (see § 63.9(h)(5)).

(2) *Application for approval of construction.* Each application for approval of construction must include, in addition to the information required in paragraph (d)(1)(ii) of this section, technical information describing the proposed nature, size, design, operating design capacity, and method of operation of the source, including an identification of each type of emission point for each type of hazardous air pollutant that is emitted (or could reasonably be anticipated to be emitted) and a description of the planned air pollution control system (equipment or method) for each emission point. The description of the equipment to be used for the control of emissions must include each control device for each hazardous air pollutant and the estimated control efficiency (percent) for each control device. The description of the method to be used for the control of emissions must include an estimated control efficiency (percent) for that method. Such technical information must include calculations of emission estimates in sufficient detail to permit assessment of the validity of the calculations.

(3) *Application for approval of reconstruction.* Each application for approval of reconstruction shall include, in addition to the information required in paragraph (d)(1)(ii) of this section -

(i) A brief description of the affected source and the components that are to be replaced;

(ii) A description of present and proposed emission control systems (i.e., equipment or methods). The description of the equipment to be used for the control of emissions shall include each control device for each hazardous air pollutant and the estimated control efficiency (percent) for each control device. The description of the method to be used for the control of emissions shall include an estimated control efficiency (percent) for that method. Such technical information shall include calculations of emission estimates in sufficient detail to permit assessment of the validity of the calculations;

(iii) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new source;

(iv) The estimated life of the affected source after the replacements; and

(v) A discussion of any economic or technical limitations the source may have in complying with relevant standards or other requirements after the proposed replacements. The discussion shall be sufficiently detailed to demonstrate to the Administrator's satisfaction that the technical or economic limitations affect the source's ability to comply with the relevant standard and how they do so.

(vi) If in the application for approval of reconstruction the owner or operator designates the affected source as a reconstructed source and declares that there are no economic or technical limitations to prevent the source from complying with all relevant standards or other requirements, the owner or operator need not submit the information required in paragraphs (d)(3)(iii) through (d)(3)(v) of this section.

(4) *Additional information.* The Administrator may request additional relevant information after the submittal of an application for approval of construction or reconstruction.

(e) *Approval of construction or reconstruction.*

(1) (i) If the Administrator determines that, if properly constructed, or reconstructed, and operated, a new or existing source for which an application under paragraph (d) of this section was submitted will not cause emissions in violation of the relevant standard(s) and any other federally enforceable requirements, the Administrator will approve the construction or reconstruction.

(ii) In addition, in the case of reconstruction, the Administrator's determination under this paragraph will be based on:

(A) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new source;

(B) The estimated life of the source after the replacements compared to the life of a comparable entirely new source;

(C) The extent to which the components being replaced cause or contribute to the emissions from the source; and

(D) Any economic or technical limitations on compliance with relevant standards that are inherent in the proposed replacements.

(2) (i) The Administrator will notify the owner or operator in writing of approval or intention to deny approval of construction or reconstruction within 60 calendar days after receipt of sufficient information to evaluate an application submitted under paragraph (d) of this section. The 60-day approval or denial period will begin after the owner or operator has been notified in writing that his/her application is complete. The Administrator will notify the owner or operator in writing of the status of his/her application, that is, whether the application contains sufficient information to make a determination, within 30 calendar days after receipt of the original application and within 30 calendar days after receipt of any supplementary information that is submitted.

(ii) When notifying the owner or operator that his/her application is not complete, the Administrator will specify the information needed to complete the application and provide notice of opportunity for the applicant to present, in writing, within 30 calendar days after he/she is notified of the incomplete application, additional information or arguments to the Administrator to enable further action on the application.

(3) Before denying any application for approval of construction or reconstruction, the Administrator will notify the applicant of the Administrator's intention to issue the denial together with -

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the applicant to present, in writing, within 30 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator to enable further action on the application.

(4) A final determination to deny any application for approval will be in writing and will specify the grounds on which the denial is based. The final determination will be made within 60 calendar days of presentation of additional information or arguments (if the application is complete), or within 60 calendar days after the final date specified for presentation if no presentation is made.

(5) Neither the submission of an application for approval nor the Administrator's approval of construction or reconstruction shall -

(i) Relieve an owner or operator of legal responsibility for compliance with any applicable provisions of this part or with any other applicable Federal, State, or local requirement; or

(ii) Prevent the Administrator from implementing or enforcing this part or taking any other action under the Act.

(f) *Approval of construction or reconstruction based on prior State preconstruction review.*

(1) Preconstruction review procedures that a State utilizes for other purposes may also be utilized for purposes of this section if the procedures are substantially equivalent to those specified in this section. The Administrator will approve an application for construction or reconstruction specified in paragraphs (b)(3) and (d) of this section if the owner or operator of a new affected source or reconstructed affected source, who is subject to such requirement meets the following conditions:

(i) The owner or operator of the new affected source or reconstructed affected source has undergone a preconstruction review and approval process in the State in which the source is (or would be) located and has received a federally enforceable construction permit that contains a finding that the source will meet the relevant promulgated emission standard, if the source is properly built and operated.

(ii) Provide a statement from the State or other evidence (such as State regulations) that it considered the factors specified in paragraph (e)(1) of this section.

(2) The owner or operator must submit to the Administrator the request for approval of construction or reconstruction under this paragraph (f)(2) no later than the application deadline specified in paragraph (d)(1) of this section (see also § 63.9(b)(2)). The owner or operator must include in the request information sufficient for the Administrator's determination. The Administrator will evaluate the owner or operator's request in accordance with the procedures specified in paragraph (e) of this section. The Administrator may request additional relevant information after the submittal of a request for approval of construction or reconstruction under this paragraph (f)(2).

§ 63.6 Compliance with standards and maintenance requirements.

(a) *Applicability.*

(1) The requirements in this section apply to the owner or operator of affected sources for which any relevant standard has been established pursuant to section 112 of the Act and the applicability of such requirements is set out in accordance with § 63.1(a)(4) unless -

(i) The Administrator (or a State with an approved permit program) has granted an extension of compliance consistent with paragraph (i) of this section; or

(ii) The President has granted an exemption from compliance with any relevant standard in accordance with section 112(i)(4) of the Act.

(2) If an area source that otherwise would be subject to an emission standard or other requirement established under this part if it were a major source subsequently increases its emissions of hazardous air pollutants (or its potential to emit hazardous air pollutants) such that the source is a major source, such source shall be subject to the relevant emission standard or other requirement.

(b) *Compliance dates for new and reconstructed sources.*

(1) Except as specified in paragraphs (b)(3) and (4) of this section, the owner or operator of a new or reconstructed affected source for which construction or reconstruction commences after proposal of a relevant standard that has an initial startup before the effective date of a relevant standard established under this part pursuant to section 112(d), (f), or (h) of the Act must comply with such standard not later than the standard's effective date.

(2) Except as specified in paragraphs (b)(3) and (4) of this section, the owner or operator of a new or reconstructed affected source that has an initial startup after the effective date of a relevant standard established under this part pursuant to section 112(d), (f), or (h) of the Act must comply with such standard upon startup of the source.

(3) The owner or operator of an affected source for which construction or reconstruction is commenced after the proposal date of a relevant standard established under this part pursuant to section 112(d), 112(f), or 112(h) of the Act but before the effective date (that is, promulgation) of such standard shall comply with the relevant emission standard not later than the date 3 years after the effective date if:

(i) The promulgated standard (that is, the relevant standard) is more stringent than the proposed standard; for purposes of this paragraph, a finding that controls or compliance methods are “more stringent” must include control technologies or performance criteria and compliance or compliance assurance methods that are different but are substantially equivalent to those required by the promulgated rule, as determined by the Administrator (or his or her authorized representative); and

(ii) The owner or operator complies with the standard as proposed during the 3-year period immediately after the effective date.

(4) The owner or operator of an affected source for which construction or reconstruction is commenced after the proposal date of a relevant standard established pursuant to section 112(d) of the Act but before the proposal date of a relevant standard established pursuant to section 112(f) shall not be required to comply with the section 112(f) emission standard until the date 10 years after the date construction or reconstruction is commenced, except that, if the section 112(f) standard is promulgated more than 10 years after construction or reconstruction is commenced, the owner or operator must comply with the standard as provided in paragraphs (b)(1) and (2) of this section.

(5) The owner or operator of a new source that is subject to the compliance requirements of paragraph (b)(3) or (4) of this section must notify the Administrator in accordance with § 63.9(d)

(6) [Reserved]

(7) When an area source increases its emissions of (or its potential to emit) hazardous air pollutants such that the source becomes a major source, the portion of the facility that meets the definition of a new affected source must comply with all requirements of that standard applicable to new sources. The source owner or operator must comply with the relevant standard upon startup.

(c) *Compliance dates for existing sources.*

(1) After the effective date of a relevant standard established under this part pursuant to section 112(d) or 112(h) of the Act, the owner or operator of an existing source shall comply with such standard by the compliance date established by the Administrator in the applicable subpart(s) of this

part, except as provided in § 63.1(c)(6)(i). Except as otherwise provided for in section 112 of the Act, in no case will the compliance date established for an existing source in an applicable subpart of this part exceed 3 years after the effective date of such standard.

(2) If an existing source is subject to a standard established under this part pursuant to section 112(f) of the Act, the owner or operator must comply with the standard by the date 90 days after the standard's effective date, or by the date specified in an extension granted to the source by the Administrator under paragraph (i)(4)(ii) of this section, whichever is later.

(3)-(4) [Reserved]

(5) Except as provided in paragraph (b)(7) of this section, the owner or operator of an area source that increases its emissions of (or its potential to emit) hazardous air pollutants such that the source becomes a major source and meets the definition of an existing source in the applicable major source standard shall be subject to relevant standards for existing sources. Except as provided in paragraph § 63.1(c)(6)(i)(B), such sources must comply by the date specified in the standards for existing area sources that become major sources. If no such compliance date is specified in the standards, the source shall have a period of time to comply with the relevant emission standard that is equivalent to the compliance period specified in the relevant standard for existing sources in existence at the time the standard becomes effective.

(d) [Reserved]

(e) *Operation and maintenance requirements.*

(1) (i) At all times, including periods of startup, shutdown, and malfunction, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices. The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require the owner or operator to achieve emission levels that would be required by the applicable standard at other times if this is not consistent with safety and good air pollution control practices, nor does it require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures (including the startup, shutdown, and malfunction plan required in paragraph (e)(3) of this section), review of operation and maintenance records, and inspection of the source.

(ii) Malfunctions must be corrected as soon as practicable after their occurrence. To the extent that an unexpected event arises during a startup, shutdown, or malfunction, an owner or operator must comply by minimizing emissions during such a startup, shutdown, and malfunction event consistent with safety and good air pollution control practices.

(iii) Operation and maintenance requirements established pursuant to section 112 of the Act are enforceable independent of emissions limitations or other requirements in relevant standards.

(2) [Reserved]

(3) *Startup, shutdown, and malfunction plan.*

(i) The owner or operator of an affected source must develop a written startup, shutdown, and malfunction plan that describes, in detail, procedures for operating and maintaining the source during periods of startup, shutdown, and malfunction; and a program of corrective action for malfunctioning process, air pollution control, and monitoring equipment used to comply with the relevant standard. The startup, shutdown, and malfunction plan does not need to address any scenario that would not cause the source to exceed an applicable emission limitation in the relevant standard. This plan must be developed by the owner or operator by the source's compliance date for that relevant standard. The purpose of the startup, shutdown, and malfunction plan is to -

(A) Ensure that, at all times, the owner or operator operates and maintains each affected source, including associated air pollution control and monitoring equipment, in a manner which satisfies the general duty to minimize emissions established by paragraph (e)(1)(i) of this section;

(B) Ensure that owners or operators are prepared to correct malfunctions as soon as practicable after their occurrence in order to minimize excess emissions of hazardous air pollutants; and

(C) Reduce the reporting burden associated with periods of startup, shutdown, and malfunction (including corrective action taken to restore malfunctioning process and air pollution control equipment to its normal or usual manner of operation).

(ii) [Reserved]

(iii) When actions taken by the owner or operator during a startup or shutdown (and the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards), or malfunction (including actions taken to correct a malfunction) are consistent with the procedures specified in the affected source's startup, shutdown, and malfunction plan, the owner or operator must keep records for that event which demonstrate that the procedures specified in the plan were followed. These records may take the form of a "checklist," or other effective form of recordkeeping that confirms conformance with the startup, shutdown, and malfunction plan and describes the actions taken for that event. In addition, the owner or operator must keep records of these events as specified in paragraph 63.10(b), including records of the occurrence and duration of each startup or shutdown (if the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards), or malfunction of operation and each malfunction of the air pollution control and monitoring equipment. Furthermore, the owner or operator shall confirm that actions taken during the relevant reporting period during periods of startup, shutdown, and malfunction were consistent with the affected source's startup, shutdown and malfunction plan in the semiannual (or more frequent) startup, shutdown, and malfunction report required in § 63.10(d)(5).

(iv) If an action taken by the owner or operator during a startup, shutdown, or malfunction (including an action taken to correct a malfunction) is not consistent with the procedures

specified in the affected source's startup, shutdown, and malfunction plan, and the source exceeds any applicable emission limitation in the relevant emission standard, then the owner or operator must record the actions taken for that event and must report such actions within 2 working days after commencing actions inconsistent with the plan, followed by a letter within 7 working days after the end of the event, in accordance with § 63.10(d)(5) (unless the owner or operator makes alternative reporting arrangements, in advance, with the Administrator).

(v) The owner or operator must maintain at the affected source a current startup, shutdown, and malfunction plan and must make the plan available upon request for inspection and copying by the Administrator. In addition, if the startup, shutdown, and malfunction plan is subsequently revised as provided in paragraph (e)(3)(viii) of this section, the owner or operator must maintain at the affected source each previous (i.e., superseded) version of the startup, shutdown, and malfunction plan, and must make each such previous version available for inspection and copying by the Administrator for a period of 5 years after revision of the plan. If at any time after adoption of a startup, shutdown, and malfunction plan the affected source ceases operation or is otherwise no longer subject to the provisions of this part, the owner or operator must retain a copy of the most recent plan for 5 years from the date the source ceases operation or is no longer subject to this part and must make the plan available upon request for inspection and copying by the Administrator. The Administrator may at any time request in writing that the owner or operator submit a copy of any startup, shutdown, and malfunction plan (or a portion thereof) which is maintained at the affected source or in the possession of the owner or operator. Upon receipt of such a request, the owner or operator must promptly submit a copy of the requested plan (or a portion thereof) to the Administrator. The owner or operator may elect to submit the required copy of any startup, shutdown, and malfunction plan to the Administrator in an electronic format. If the owner or operator claims that any portion of such a startup, shutdown, and malfunction plan is confidential business information entitled to protection from disclosure under section 114(c) of the Act or 40 CFR 2.301, the material which is claimed as confidential must be clearly designated in the submission.

(vi) To satisfy the requirements of this section to develop a startup, shutdown, and malfunction plan, the owner or operator may use the affected source's standard operating procedures (SOP) manual, or an Occupational Safety and Health Administration (OSHA) or other plan, provided the alternative plans meet all the requirements of this section and are made available for inspection or submitted when requested by the Administrator.

(vii) Based on the results of a determination made under paragraph (e)(1)(i) of this section, the Administrator may require that an owner or operator of an affected source make changes to the startup, shutdown, and malfunction plan for that source. The Administrator must require appropriate revisions to a startup, shutdown, and malfunction plan, if the Administrator finds that the plan:

(A) Does not address a startup, shutdown, or malfunction event that has occurred;

(B) Fails to provide for the operation of the source (including associated air pollution control and monitoring equipment) during a startup, shutdown, or malfunction event in a manner consistent with the general duty to minimize emissions established by paragraph (e)(1)(i) of this section;

(C) Does not provide adequate procedures for correcting malfunctioning process and/or air pollution control and monitoring equipment as quickly as practicable; or

(D) Includes an event that does not meet the definition of startup, shutdown, or malfunction listed in § 63.2.

(viii) The owner or operator may periodically revise the startup, shutdown, and malfunction plan for the affected source as necessary to satisfy the requirements of this part or to reflect changes in equipment or procedures at the affected source. Unless the permitting authority provides otherwise, the owner or operator may make such revisions to the startup, shutdown, and malfunction plan without prior approval by the Administrator or the permitting authority. However, each such revision to a startup, shutdown, and malfunction plan must be reported in the semiannual report required by § 63.10(d)(5). If the startup, shutdown, and malfunction plan fails to address or inadequately addresses an event that meets the characteristics of a malfunction but was not included in the startup, shutdown, and malfunction plan at the time the owner or operator developed the plan, the owner or operator must revise the startup, shutdown, and malfunction plan within 45 days after the event to include detailed procedures for operating and maintaining the source during similar malfunction events and a program of corrective action for similar malfunctions of process or air pollution control and monitoring equipment. In the event that the owner or operator makes any revision to the startup, shutdown, and malfunction plan which alters the scope of the activities at the source which are deemed to be a startup, shutdown, or malfunction, or otherwise modifies the applicability of any emission limit, work practice requirement, or other requirement in a standard established under this part, the revised plan shall not take effect until after the owner or operator has provided a written notice describing the revision to the permitting authority.

(ix) The title V permit for an affected source must require that the owner or operator develop a startup, shutdown, and malfunction plan which conforms to the provisions of this part, but may do so by citing to the relevant subpart or subparagraphs of paragraph (e) of this section. However, any revisions made to the startup, shutdown, and malfunction plan in accordance with the procedures established by this part shall not be deemed to constitute permit revisions under part 70 or part 71 of this chapter and the elements of the startup, shutdown, and malfunction plan shall not be considered an applicable requirement as defined in § 70.2 and § 71.2 of this chapter. Moreover, none of the procedures specified by the startup, shutdown, and malfunction plan for an affected source shall be deemed to fall within the permit shield provision in section 504(f) of the Act.

(f) *Compliance with nonopacity emission standards* -

(1) *Applicability.* The non-opacity emission standards set forth in this part shall apply at all times except as otherwise specified in an applicable subpart. If a startup, shutdown, or malfunction of one portion of an affected source does not affect the ability of particular emission points within other portions of the affected source to comply with the non-opacity emission standards set forth in this part, then that emission point must still be required to comply with the non-opacity emission standards and other applicable requirements.

(2) *Methods for determining compliance.*

(i) The Administrator will determine compliance with nonopacity emission standards in this part based on the results of performance tests conducted according to the procedures in § 63.7, unless otherwise specified in an applicable subpart of this part.

(ii) The Administrator will determine compliance with nonopacity emission standards in this part by evaluation of an owner or operator's conformance with operation and maintenance requirements, including the evaluation of monitoring data, as specified in § 63.6(e) and applicable subparts of this part.

(iii) If an affected source conducts performance testing at startup to obtain an operating permit in the State in which the source is located, the results of such testing may be used to demonstrate compliance with a relevant standard if -

(A) The performance test was conducted within a reasonable amount of time before an initial performance test is required to be conducted under the relevant standard;

(B) The performance test was conducted under representative operating conditions for the source;

(C) The performance test was conducted and the resulting data were reduced using EPA-approved test methods and procedures, as specified in § 63.7(e) of this subpart; and

(D) The performance test was appropriately quality-assured, as specified in § 63.7(c).

(iv) The Administrator will determine compliance with design, equipment, work practice, or operational emission standards in this part by review of records, inspection of the source, and other procedures specified in applicable subparts of this part.

(v) The Administrator will determine compliance with design, equipment, work practice, or operational emission standards in this part by evaluation of an owner or operator's conformance with operation and maintenance requirements, as specified in paragraph (e) of this section and applicable subparts of this part.

(3) *Finding of compliance.* The Administrator will make a finding concerning an affected source's compliance with a non-opacity emission standard, as specified in paragraphs (f)(1) and (2) of this section, upon obtaining all the compliance information required by the relevant standard (including the written reports of performance test results, monitoring results, and other information, if applicable), and information available to the Administrator pursuant to paragraph (e)(1)(i) of this section.

(g) *Use of an alternative nonopacity emission standard.*

(1) If, in the Administrator's judgment, an owner or operator of an affected source has established that an alternative means of emission limitation will achieve a reduction in emissions of a hazardous air pollutant from an affected source at least equivalent to the reduction in emissions of that pollutant from that source achieved under any design, equipment, work practice, or operational emission standard, or combination thereof, established under this part pursuant to section 112(h) of the Act, the Administrator will publish in the Federal Register a notice permitting the use of the alternative emission standard for purposes of compliance with the promulgated standard. Any Federal Register

notice under this paragraph shall be published only after the public is notified and given the opportunity to comment. Such notice will restrict the permission to the stationary source(s) or category(ies) of sources from which the alternative emission standard will achieve equivalent emission reductions. The Administrator will condition permission in such notice on requirements to assure the proper operation and maintenance of equipment and practices required for compliance with the alternative emission standard and other requirements, including appropriate quality assurance and quality control requirements, that are deemed necessary.

(2) An owner or operator requesting permission under this paragraph shall, unless otherwise specified in an applicable subpart, submit a proposed test plan or the results of testing and monitoring in accordance with § 63.7 and § 63.8, a description of the procedures followed in testing or monitoring, and a description of pertinent conditions during testing or monitoring. Any testing or monitoring conducted to request permission to use an alternative nonopacity emission standard shall be appropriately quality assured and quality controlled, as specified in § 63.7 and § 63.8.

(3) The Administrator may establish general procedures in an applicable subpart that accomplish the requirements of paragraphs (g)(1) and (g)(2) of this section.

(h) *Compliance with opacity and visible emission standards* -

(1) *Applicability.* The opacity and visible emission standards set forth in this part must apply at all times except as otherwise specified in an applicable subpart. If a startup, shutdown, or malfunction of one portion of an affected source does not affect the ability of particular emission points within other portions of the affected source to comply with the opacity and visible emission standards set forth in this part, then that emission point shall still be required to comply with the opacity and visible emission standards and other applicable requirements.

(2) *Methods for determining compliance.*

(i) The Administrator will determine compliance with opacity and visible emission standards in this part based on the results of the test method specified in an applicable subpart. Whenever a continuous opacity monitoring system (COMS) is required to be installed to determine compliance with numerical opacity emission standards in this part, compliance with opacity emission standards in this part shall be determined by using the results from the COMS. Whenever an opacity emission test method is not specified, compliance with opacity emission standards in this part shall be determined by conducting observations in accordance with Test Method 9 in appendix A of part 60 of this chapter or the method specified in paragraph (h)(7)(ii) of this section. Whenever a visible emission test method is not specified, compliance with visible emission standards in this part shall be determined by conducting observations in accordance with Test Method 22 in appendix A of part 60 of this chapter.

(ii) [Reserved]

(iii) If an affected source undergoes opacity or visible emission testing at startup to obtain an operating permit in the State in which the source is located, the results of such testing may be used to demonstrate compliance with a relevant standard if -

(A) The opacity or visible emission test was conducted within a reasonable amount of time before a performance test is required to be conducted under the relevant standard;

(B) The opacity or visible emission test was conducted under representative operating conditions for the source;

(C) The opacity or visible emission test was conducted and the resulting data were reduced using EPA-approved test methods and procedures, as specified in § 63.7(e); and

(D) The opacity or visible emission test was appropriately quality-assured, as specified in § 63.7(c) of this section.

(3) [Reserved]

(4) *Notification of opacity or visible emission observations.* The owner or operator of an affected source shall notify the Administrator in writing of the anticipated date for conducting opacity or visible emission observations in accordance with § 63.9(f), if such observations are required for the source by a relevant standard.

(5) *Conduct of opacity or visible emission observations.* When a relevant standard under this part includes an opacity or visible emission standard, the owner or operator of an affected source shall comply with the following:

(i) For the purpose of demonstrating initial compliance, opacity or visible emission observations shall be conducted concurrently with the initial performance test required in § 63.7 unless one of the following conditions applies:

(A) If no performance test under § 63.7 is required, opacity or visible emission observations shall be conducted within 60 days after achieving the maximum production rate at which a new or reconstructed source will be operated, but not later than 120 days after initial startup of the source, or within 120 days after the effective date of the relevant standard in the case of new sources that start up before the standard's effective date. If no performance test under § 63.7 is required, opacity or visible emission observations shall be conducted within 120 days after the compliance date for an existing or modified source; or

(B) If visibility or other conditions prevent the opacity or visible emission observations from being conducted concurrently with the initial performance test required under § 63.7, or within the time period specified in paragraph (h)(5)(i)(A) of this section, the source's owner or operator shall reschedule the opacity or visible emission observations as soon after the initial performance test, or time period, as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. The rescheduled opacity or visible emission observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under § 63.7. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity or visible emission observations from being made concurrently with the initial performance test in

accordance with procedures contained in Test Method 9 or Test Method 22 in appendix A of part 60 of this chapter.

(ii) For the purpose of demonstrating initial compliance, the minimum total time of opacity observations shall be 3 hours (30 6-minute averages) for the performance test or other required set of observations (e.g., for fugitive-type emission sources subject only to an opacity emission standard).

(iii) The owner or operator of an affected source to which an opacity or visible emission standard in this part applies shall conduct opacity or visible emission observations in accordance with the provisions of this section, record the results of the evaluation of emissions, and report to the Administrator the opacity or visible emission results in accordance with the provisions of § 63.10(d).

(iv) [Reserved]

(v) Opacity readings of portions of plumes that contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity emission standards.

(6) *Availability of records.* The owner or operator of an affected source shall make available, upon request by the Administrator, such records that the Administrator deems necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification.

(7) *Use of a continuous opacity monitoring system.*

(i) The owner or operator of an affected source required to use a continuous opacity monitoring system (COMS) shall record the monitoring data produced during a performance test required under § 63.7 and shall furnish the Administrator a written report of the monitoring results in accordance with the provisions of § 63.10(e)(4).

(ii) Whenever an opacity emission test method has not been specified in an applicable subpart, or an owner or operator of an affected source is required to conduct Test Method 9 observations (see appendix A of part 60 of this chapter), the owner or operator may submit, for compliance purposes, COMS data results produced during any performance test required under § 63.7 in lieu of Method 9 data. If the owner or operator elects to submit COMS data for compliance with the opacity emission standard, he or she shall notify the Administrator of that decision, in writing, simultaneously with the notification under § 63.7(b) of the date the performance test is scheduled to begin. Once the owner or operator of an affected source has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent performance tests required under § 63.7, unless the owner or operator notifies the Administrator in writing to the contrary not later than with the notification under § 63.7(b) of the date the subsequent performance test is scheduled to begin.

(iii) For the purposes of determining compliance with the opacity emission standard during a performance test required under § 63.7 using COMS data, the COMS data shall be reduced to 6-minute averages over the duration of the mass emission performance test.

(iv) The owner or operator of an affected source using a COMS for compliance purposes is responsible for demonstrating that he/she has complied with the performance evaluation

requirements of § 63.8(e), that the COMS has been properly maintained, operated, and data quality-assured, as specified in § 63.8(c) and § 63.8(d), and that the resulting data have not been altered in any way.

(v) Except as provided in paragraph (h)(7)(ii) of this section, the results of continuous monitoring by a COMS that indicate that the opacity at the time visual observations were made was not in excess of the emission standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the affected source proves that, at the time of the alleged violation, the instrument used was properly maintained, as specified in § 63.8(c), and met Performance Specification 1 in appendix B of part 60 of this chapter, and that the resulting data have not been altered in any way.

(8) *Finding of compliance.* The Administrator will make a finding concerning an affected source's compliance with an opacity or visible emission standard upon obtaining all the compliance information required by the relevant standard (including the written reports of the results of the performance tests required by § 63.7, the results of Test Method 9 or another required opacity or visible emission test method, the observer certification required by paragraph (h)(6) of this section, and the continuous opacity monitoring system results, whichever is/are applicable) and any information available to the Administrator needed to determine whether proper operation and maintenance practices are being used.

(9) *Adjustment to an opacity emission standard.*

(i) If the Administrator finds under paragraph (h)(8) of this section that an affected source is in compliance with all relevant standards for which initial performance tests were conducted under § 63.7, but during the time such performance tests were conducted fails to meet any relevant opacity emission standard, the owner or operator of such source may petition the Administrator to make appropriate adjustment to the opacity emission standard for the affected source. Until the Administrator notifies the owner or operator of the appropriate adjustment, the relevant opacity emission standard remains applicable.

(ii) The Administrator may grant such a petition upon a demonstration by the owner or operator that -

(A) The affected source and its associated air pollution control equipment were operated and maintained in a manner to minimize the opacity of emissions during the performance tests;

(B) The performance tests were performed under the conditions established by the Administrator; and

(C) The affected source and its associated air pollution control equipment were incapable of being adjusted or operated to meet the relevant opacity emission standard.

(iii) The Administrator will establish an adjusted opacity emission standard for the affected source meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity emission standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity emission standard in the Federal Register.

(iv) After the Administrator promulgates an adjusted opacity emission standard for an affected source, the owner or operator of such source shall be subject to the new opacity emission standard, and the new opacity emission standard shall apply to such source during any subsequent performance tests.

(i) *Extension of compliance with emission standards.*

(1) Until an extension of compliance has been granted by the Administrator (or a State with an approved permit program) under this paragraph, the owner or operator of an affected source subject to the requirements of this section shall comply with all applicable requirements of this part.

(2) *Extension of compliance for early reductions and other reductions* -

(i) *Early reductions.* Pursuant to section 112(i)(5) of the Act, if the owner or operator of an existing source demonstrates that the source has achieved a reduction in emissions of hazardous air pollutants in accordance with the provisions of subpart D of this part, the Administrator (or the State with an approved permit program) will grant the owner or operator an extension of compliance with specific requirements of this part, as specified in subpart D.

(ii) *Other reductions.* Pursuant to section 112(i)(6) of the Act, if the owner or operator of an existing source has installed best available control technology (BACT) (as defined in section 169(3) of the Act) or technology required to meet a lowest achievable emission rate (LAER) (as defined in section 171 of the Act) prior to the promulgation of an emission standard in this part applicable to such source and the same pollutant (or stream of pollutants) controlled pursuant to the BACT or LAER installation, the Administrator will grant the owner or operator an extension of compliance with such emission standard that will apply until the date 5 years after the date on which such installation was achieved, as determined by the Administrator.

(3) *Request for extension of compliance.* Paragraphs (i)(4) through (i)(7) of this section concern requests for an extension of compliance with a relevant standard under this part (except requests for an extension of compliance under paragraph (i)(2)(i) of this section will be handled through procedures specified in subpart D of this part).

(4) (i) (A) The owner or operator of an existing source who is unable to comply with a relevant standard established under this part pursuant to section 112(d) of the Act may request that the Administrator (or a State, when the State has an approved part 70 permit program and the source is required to obtain a part 70 permit under that program, or a State, when the State has been delegated the authority to implement and enforce the emission standard for that source) grant an extension allowing the source up to 1 additional year to comply with the standard, if such additional period is necessary for the installation of controls. An additional extension of up to 3 years may be added for mining waste operations, if the 1-year extension of compliance is insufficient to dry and cover mining waste in order to reduce emissions of any hazardous air pollutant. The owner or operator of an affected source who has requested an extension of compliance under this paragraph and who is otherwise required to obtain a title V permit shall apply for such permit or apply to have the source's title V permit revised to incorporate the conditions of the extension of compliance. The conditions of an extension of compliance granted under this paragraph will be incorporated into the affected source's title V permit according to the provisions of part 70 or Federal title V regulations in this chapter (42 U.S.C. 7661), whichever are applicable.

(B) Any request under this paragraph for an extension of compliance with a relevant standard must be submitted in writing to the appropriate authority no later than 120 days prior to the affected source's compliance date (as specified in paragraphs (b) and (c) of this section), except as provided for in paragraph (i)(4)(i)(C) of this section. Nonfrivolous requests submitted under this paragraph will stay the applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the date of denial. Emission standards established under this part may specify alternative dates for the submittal of requests for an extension of compliance if alternatives are appropriate for the source categories affected by those standards.

(C) An owner or operator may submit a compliance extension request after the date specified in paragraph (i)(4)(i)(B) of this section provided the need for the compliance extension arose after that date, and before the otherwise applicable compliance date and the need arose due to circumstances beyond reasonable control of the owner or operator. This request must include, in addition to the information required in paragraph (i)(6)(i) of this section, a statement of the reasons additional time is needed and the date when the owner or operator first learned of the problems. Nonfrivolous requests submitted under this paragraph will stay the applicability of the rule as to the emission points in question until such time as the request is granted or denied. A denial will be effective as of the original compliance date.

(ii) The owner or operator of an existing source unable to comply with a relevant standard established under this part pursuant to section 112(f) of the Act may request that the Administrator grant an extension allowing the source up to 2 years after the standard's effective date to comply with the standard. The Administrator may grant such an extension if he/she finds that such additional period is necessary for the installation of controls and that steps will be taken during the period of the extension to assure that the health of persons will be protected from imminent endangerment. Any request for an extension of compliance with a relevant standard under this paragraph must be submitted in writing to the Administrator not later than 90 calendar days after the effective date of the relevant standard.

(5) The owner or operator of an existing source that has installed BACT or technology required to meet LAER [as specified in paragraph (i)(2)(ii) of this section] prior to the promulgation of a relevant emission standard in this part may request that the Administrator grant an extension allowing the source 5 years from the date on which such installation was achieved, as determined by the Administrator, to comply with the standard. Any request for an extension of compliance with a relevant standard under this paragraph shall be submitted in writing to the Administrator not later than 120 days after the promulgation date of the standard. The Administrator may grant such an extension if he or she finds that the installation of BACT or technology to meet LAER controls the same pollutant (or stream of pollutants) that would be controlled at that source by the relevant emission standard.

(6) (i) The request for a compliance extension under paragraph (i)(4) of this section shall include the following information:

(A) A description of the controls to be installed to comply with the standard;

(B) A compliance schedule, including the date by which each step toward compliance will be reached. At a minimum, the list of dates shall include:

(*1*) The date by which on-site construction, installation of emission control equipment, or a process change is planned to be initiated; and

(*2*) The date by which final compliance is to be achieved.

(*3*) The date by which on-site construction, installation of emission control equipment, or a process change is to be completed; and

(*4*) The date by which final compliance is to be achieved;

(C)-(D)

(ii) The request for a compliance extension under paragraph (i)(5) of this section shall include all information needed to demonstrate to the Administrator's satisfaction that the installation of BACT or technology to meet LAER controls the same pollutant (or stream of pollutants) that would be controlled at that source by the relevant emission standard.

(7) Advice on requesting an extension of compliance may be obtained from the Administrator (or the State with an approved permit program).

(8) *Approval of request for extension of compliance.* Paragraphs (i)(9) through (i)(14) of this section concern approval of an extension of compliance requested under paragraphs (i)(4) through (i)(6) of this section.

(9) Based on the information provided in any request made under paragraphs (i)(4) through (i)(6) of this section, or other information, the Administrator (or the State with an approved permit program) may grant an extension of compliance with an emission standard, as specified in paragraphs (i)(4) and (i)(5) of this section.

(10) The extension will be in writing and will -

(i) Identify each affected source covered by the extension;

(ii) Specify the termination date of the extension;

(iii) Specify the dates by which steps toward compliance are to be taken, if appropriate;

(iv) Specify other applicable requirements to which the compliance extension applies (e.g., performance tests); and

(v) (A) Under paragraph (i)(4), specify any additional conditions that the Administrator (or the State) deems necessary to assure installation of the necessary controls and protection of the health of persons during the extension period; or

(B) Under paragraph (i)(5), specify any additional conditions that the Administrator deems necessary to assure the proper operation and maintenance of the installed controls during the extension period.

(11) The owner or operator of an existing source that has been granted an extension of compliance under paragraph (i)(10) of this section may be required to submit to the Administrator (or the State with an approved permit program) progress reports indicating whether the steps toward compliance

outlined in the compliance schedule have been reached. The contents of the progress reports and the dates by which they shall be submitted will be specified in the written extension of compliance granted under paragraph (i)(10) of this section.

(12) (i) The Administrator (or the State with an approved permit program) will notify the owner or operator in writing of approval or intention to deny approval of a request for an extension of compliance within 30 calendar days after receipt of sufficient information to evaluate a request submitted under paragraph (i)(4)(i) or (i)(5) of this section. The Administrator (or the State) will notify the owner or operator in writing of the status of his/her application, that is, whether the application contains sufficient information to make a determination, within 30 calendar days after receipt of the original application and within 30 calendar days after receipt of any supplementary information that is submitted. The 30-day approval or denial period will begin after the owner or operator has been notified in writing that his/her application is complete.

(ii) When notifying the owner or operator that his/her application is not complete, the Administrator will specify the information needed to complete the application and provide notice of opportunity for the applicant to present, in writing, within 30 calendar days after he/she is notified of the incomplete application, additional information or arguments to the Administrator to enable further action on the application.

(iii) Before denying any request for an extension of compliance, the Administrator (or the State with an approved permit program) will notify the owner or operator in writing of the Administrator's (or the State's) intention to issue the denial, together with -

(A) Notice of the information and findings on which the intended denial is based; and

(B) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator (or the State) before further action on the request.

(iv) The Administrator's final determination to deny any request for an extension will be in writing and will set forth the specific grounds on which the denial is based. The final determination will be made within 30 calendar days after presentation of additional information or argument (if the application is complete), or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(13) (i) The Administrator will notify the owner or operator in writing of approval or intention to deny approval of a request for an extension of compliance within 30 calendar days after receipt of sufficient information to evaluate a request submitted under paragraph (i)(4)(ii) of this section. The 30-day approval or denial period will begin after the owner or operator has been notified in writing that his/her application is complete. The Administrator (or the State) will notify the owner or operator in writing of the status of his/her application, that is, whether the application contains sufficient information to make a determination, within 15 calendar days after receipt of the original application and within 15 calendar days after receipt of any supplementary information that is submitted.

(ii) When notifying the owner or operator that his/her application is not complete, the Administrator will specify the information needed to complete the application and provide notice of opportunity for the applicant to present, in writing, within 15 calendar days after

he/she is notified of the incomplete application, additional information or arguments to the Administrator to enable further action on the application.

(iii) Before denying any request for an extension of compliance, the Administrator will notify the owner or operator in writing of the Administrator's intention to issue the denial, together with -

(A) Notice of the information and findings on which the intended denial is based; and

(B) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator before further action on the request.

(iv) A final determination to deny any request for an extension will be in writing and will set forth the specific grounds on which the denial is based. The final determination will be made within 30 calendar days after presentation of additional information or argument (if the application is complete), or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(14) The Administrator (or the State with an approved permit program) may terminate an extension of compliance at an earlier date than specified if any specification under paragraph (i)(10)(iii) or (iv) of this section is not met. Upon a determination to terminate, the Administrator will notify, in writing, the owner or operator of the Administrator's determination to terminate, together with:

(i) Notice of the reason for termination; and

(ii) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the determination to terminate, additional information or arguments to the Administrator before further action on the termination.

(iii) A final determination to terminate an extension of compliance will be in writing and will set forth the specific grounds on which the termination is based. The final determination will be made within 30 calendar days after presentation of additional information or arguments, or within 30 calendar days after the final date specified for the presentation if no presentation is made.

(15) [Reserved]

(16) The granting of an extension under this section shall not abrogate the Administrator's authority under section 114 of the Act.

(j) *Exemption from compliance with emission standards.* The President may exempt any stationary source from compliance with any relevant standard established pursuant to section 112 of the Act for a period of not more than 2 years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. An exemption under this paragraph may be extended for 1 or more additional periods, each period not to exceed 2 years.

§ 63.7 Performance testing requirements.

(a) *Applicability and performance test dates.*

(1) The applicability of this section is set out in § 63.1(a)(4).

(2) Except as provided in paragraph (a)(4) of this section, if required to do performance testing by a relevant standard, and unless a waiver of performance testing is obtained under this section or the conditions of paragraph (c)(3)(ii)(B) of this section apply, the owner or operator of the affected source must perform such tests within 180 days of the compliance date for such source.

(i)-(viii) [Reserved]

(ix) Except as provided in paragraph (a)(4) of this section, when an emission standard promulgated under this part is more stringent than the standard proposed (see § 63.6(b)(3)), the owner or operator of a new or reconstructed source subject to that standard for which construction or reconstruction is commenced between the proposal and promulgation dates of the standard shall comply with performance testing requirements within 180 days after the standard's effective date, or within 180 days after startup of the source, whichever is later. If the promulgated standard is more stringent than the proposed standard, the owner or operator may choose to demonstrate compliance with either the proposed or the promulgated standard. If the owner or operator chooses to comply with the proposed standard initially, the owner or operator shall conduct a second performance test within 3 years and 180 days after the effective date of the standard, or after startup of the source, whichever is later, to demonstrate compliance with the promulgated standard.

(3) The Administrator may require an owner or operator to conduct performance tests at the affected source at any other time when the action is authorized by section 114 of the Act.

(4) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure:

(i) The owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline specified in paragraph (a)(2) or (a)(3) of this section, or elsewhere in this part, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(ii) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(iii) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(iv) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(4)(i), (a)(4)(ii), and (a)(4)(iii) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) *Notification of performance test.*

(1) The owner or operator of an affected source must notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin to allow the Administrator, upon request, to review an approve the site-specific test plan required under paragraph (c) of this section and to have an observer present during the test.

(2) In the event the owner or operator is unable to conduct the performance test on the date specified in the notification requirement specified in paragraph (b)(1) of this section due to unforeseeable circumstances beyond his or her control, the owner or operator must notify the Administrator as soon as practicable and without delay prior to the scheduled performance test date and specify the date when the performance test is rescheduled. This notification of delay in conducting the performance test shall not relieve the owner or operator of legal responsibility for compliance with any other applicable provisions of this part or with any other applicable Federal, State, or local requirement, nor will it prevent the Administrator from implementing or enforcing this part or taking any other action under the Act.

(c) *Quality assurance program.*

(1) The results of the quality assurance program required in this paragraph will be considered by the Administrator when he/she determines the validity of a performance test.

(2) (i) *Submission of site-specific test plan.* Before conducting a required performance test, the owner or operator of an affected source shall develop and, if requested by the Administrator, shall submit a site-specific test plan to the Administrator for approval. The test plan shall include a test program summary, the test schedule, data quality objectives, and both an internal and external quality assurance (QA) program. Data quality objectives are the pretest expectations of precision, accuracy, and completeness of data.

(ii) The internal QA program shall include, at a minimum, the activities planned by routine operators and analysts to provide an assessment of test data precision; an example of internal QA is the sampling and analysis of replicate samples.

(iii) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may

waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(A) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A-3 of part 60 of this chapter; Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60; Methods 18 and 19 of appendix A-6 of part 60; Methods 20, 22, and 25A of appendix A-7 of part 60; Methods 30A and 30B of appendix A-8 of part 60; and Methods 303, 318, 320, and 321 of appendix A of this part. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *www.epa.gov/ttn/emc,* to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP.

The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request, and the compliance authority may grant, a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and then report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(B) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

(*1*) Preparing the sample;

(*2*) Confirming the true concentration of the sample;

(*3*) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range;

(*4*) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(*5*) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(*6*) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(*7*) Reporting the results from each audit sample in a timely manner to the compliance authority and to the source owner, operator, or representative by the AASP. The AASP shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.

(*8*) Evaluating the acceptance limits of samples at least once every two years to determine in consultation with the voluntary consensus standard body if they should be changed.

(*9*) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(C) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

(*1*) Checking audit samples to confirm their true value as reported by the AASP.

(*2*) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years.

(*3*) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(D) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget *Circular A-119.* A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at *http://standards.gov/standards_gov/a119.cfm.* The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria documents do not meet the minimum technical requirements in paragraphs (c)(2)(iii)(B) through (C) of this section, the technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, *http://www.epa.gov/ttn/emc.*

(iv) The owner or operator of an affected source shall submit the site-specific test plan to the Administrator upon the Administrator's request at least 60 calendar days before the performance test is scheduled to take place, that is, simultaneously with the notification of intention to conduct a performance test required under paragraph (b) of this section, or on a mutually agreed upon date.

(v) The Administrator may request additional relevant information after the submittal of a site-specific test plan.

(3) *Approval of site-specific test plan.*

(i) The Administrator will notify the owner or operator of approval or intention to deny approval of the site-specific test plan (if review of the site-specific test plan is requested) within 30 calendar days after receipt of the original plan and within 30 calendar days after receipt of any supplementary information that is submitted under paragraph (c)(3)(i)(B) of this section. Before disapproving any site-specific test plan, the Administrator will notify the applicant of the Administrator's intention to disapprove the plan together with -

(A) Notice of the information and findings on which the intended disapproval is based; and

(B) Notice of opportunity for the owner or operator to present, within 30 calendar days after he/she is notified of the intended disapproval, additional information to the Administrator before final action on the plan.

(ii) In the event that the Administrator fails to approve or disapprove the site-specific test plan within the time period specified in paragraph (c)(3)(i) of this section, the following conditions shall apply:

(A) If the owner or operator intends to demonstrate compliance using the test method(s) specified in the relevant standard or with only minor changes to those tests methods (see paragraph (e)(2)(i) of this section), the owner or operator must conduct the performance test within the time specified in this section using the specified method(s);

(B) If the owner or operator intends to demonstrate compliance by using an alternative to any test method specified in the relevant standard, the owner or operator is authorized to conduct the performance test using an alternative test method after the Administrator approves the use of the alternative method when the Administrator approves the site-specific test plan (if review of the site-specific test plan is requested) or after the alternative method is approved (see paragraph (f) of this section). However, the owner or operator is authorized to conduct the performance test using an alternative method in the absence of notification of approval 45 days after submission of the site-specific test plan or request to use an alternative method. The owner or operator is authorized to conduct the performance test within 60 calendar days after he/she is authorized to demonstrate compliance using an alternative test method. Notwithstanding the requirements in the preceding three sentences, the owner or operator may proceed to conduct the performance test as required in this section (without the Administrator's prior approval of the site-specific test plan) if he/she subsequently chooses to use the specified testing and monitoring methods instead of an alternative.

(iii) Neither the submission of a site-specific test plan for approval, nor the Administrator's approval or disapproval of a plan, nor the Administrator's failure to approve or disapprove a plan in a timely manner shall -

(A) Relieve an owner or operator of legal responsibility for compliance with any applicable provisions of this part or with any other applicable Federal, State, or local requirement; or

(B) Prevent the Administrator from implementing or enforcing this part or taking any other action under the Act.

(d) *Performance testing facilities.* If required to do performance testing, the owner or operator of each new source and, at the request of the Administrator, the owner or operator of each existing source, shall provide performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such source. This includes:

(i) Constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures; and

(ii) Providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures;

(2) Safe sampling platform(s);

(3) Safe access to sampling platform(s);

(4) Utilities for sampling and testing equipment; and

(5) Any other facilities that the Administrator deems necessary for safe and adequate testing of a source.

(e) *Conduct of performance tests.*

(1) Performance tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance (i.e., performance based on normal operating conditions) of the affected source. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test, nor shall emissions in excess of the level of the relevant standard during periods of startup, shutdown, and malfunction be considered a violation of the relevant standard unless otherwise specified in the relevant standard or a determination of noncompliance is made under § 63.6(e). Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(2) Performance tests shall be conducted and data shall be reduced in accordance with the test methods and procedures set forth in this section, in each relevant standard, and, if required, in applicable appendices of parts 51, 60, 61, and 63 of this chapter unless the Administrator -

(i) Specifies or approves, in specific cases, the use of a test method with minor changes in methodology (see definition in § 63.90(a)). Such changes may be approved in conjunction with approval of the site-specific test plan (see paragraph (c) of this section); or

(ii) Approves the use of an intermediate or major change or alternative to a test method (see definitions in § 63.90(a)), the results of which the Administrator has determined to be adequate for indicating whether a specific affected source is in compliance; or

(iii) Approves shorter sampling times or smaller sample volumes when necessitated by process variables or other factors; or

(iv) Waives the requirement for performance tests because the owner or operator of an affected source has demonstrated by other means to the Administrator's satisfaction that the affected source is in compliance with the relevant standard.

(3) Unless otherwise specified in a relevant standard or test method, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the relevant standard. For the purpose of determining compliance with a relevant standard, the arithmetic mean of the results of the three runs shall apply. Upon receiving approval from the Administrator, results of a test run may be replaced with results of an additional test run in the event that -

(i) A sample is accidentally lost after the testing team leaves the site; or

(ii) Conditions occur in which one of the three runs must be discontinued because of forced shutdown; or

(iii) Extreme meteorological conditions occur; or

(iv) Other circumstances occur that are beyond the owner or operator's control.

(4) Nothing in paragraphs (e)(1) through (e)(3) of this section shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(f) *Use of an alternative test method* -

(1) *General.* Until authorized to use an intermediate or major change or alternative to a test method, the owner or operator of an affected source remains subject to the requirements of this section and the relevant standard.

(2) The owner or operator of an affected source required to do performance testing by a relevant standard may use an alternative test method from that specified in the standard provided that the owner or operator -

(i) Notifies the Administrator of his or her intention to use an alternative test method at least 60 days before the performance test is scheduled to begin;

(ii) Uses Method 301 in appendix A of this part to validate the alternative test method. This may include the use of specific procedures of Method 301 if use of such procedures are sufficient to validate the alternative test method; and

(iii) Submits the results of the Method 301 validation process along with the notification of intention and the justification for not using the specified test method. The owner or operator may submit the information required in this paragraph well in advance of the deadline specified in paragraph (f)(2)(i) of this section to ensure a timely review by the Administrator in order to meet the performance test date specified in this section or the relevant standard.

(3) The Administrator will determine whether the owner or operator's validation of the proposed alternative test method is adequate and issue an approval or disapproval of the alternative test method. If the owner or operator intends to demonstrate compliance by using an alternative to any

test method specified in the relevant standard, the owner or operator is authorized to conduct the performance test using an alternative test method after the Administrator approves the use of the alternative method. However, the owner or operator is authorized to conduct the performance test using an alternative method in the absence of notification of approval/disapproval 45 days after submission of the request to use an alternative method and the request satisfies the requirements in paragraph (f)(2) of this section. The owner or operator is authorized to conduct the performance test within 60 calendar days after he/she is authorized to demonstrate compliance using an alternative test method. Notwithstanding the requirements in the preceding three sentences, the owner or operator may proceed to conduct the performance test as required in this section (without the Administrator's prior approval of the site-specific test plan) if he/she subsequently chooses to use the specified testing and monitoring methods instead of an alternative.

(4) If the Administrator finds reasonable grounds to dispute the results obtained by an alternative test method for the purposes of demonstrating compliance with a relevant standard, the Administrator may require the use of a test method specified in a relevant standard.

(5) If the owner or operator uses an alternative test method for an affected source during a required performance test, the owner or operator of such source shall continue to use the alternative test method for subsequent performance tests at that affected source until he or she receives approval from the Administrator to use another test method as allowed under § 63.7(f).

(6) Neither the validation and approval process nor the failure to validate an alternative test method shall abrogate the owner or operator's responsibility to comply with the requirements of this part.

(g) *Data analysis, recordkeeping, and reporting.*

(1) Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, results of a performance test shall include the analysis of samples, determination of emissions, and raw data. A performance test is “completed” when field sample collection is terminated. The owner or operator of an affected source shall report the results of the performance test to the Administrator before the close of business on the 60th day following the completion of the performance test, unless specified otherwise in a relevant standard or as approved otherwise in writing by the Administrator (see § 63.9(i)). The results of the performance test shall be submitted as part of the notification of compliance status required under § 63.9(h). Before a title V permit has been issued to the owner or operator of an affected source, the owner or operator shall send the results of the performance test to the Administrator. After a title V permit has been issued to the owner or operator of an affected source, the owner or operator shall send the results of the performance test to the appropriate permitting authority.

(2) Contents of a performance test, CMS performance evaluation, or CMS quality assurance test report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard, test method, CMS performance specification, or quality assurance requirement for a CMS, or as otherwise approved by the Administrator in writing, the report shall include the elements identified in paragraphs (g)(2)(i) through (vi) of this section.

(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry System (FRS) number for the facility.

(ii) Purpose of the test including the applicable regulation requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard, and any process parameter component, and a brief process description.

(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.

(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.

(v) Where a test method, CEMS, PEMS, or COMS performance specification, or on-going quality assurance requirement for a CEMS, PEMS, or COMS requires you record or report, the following shall be included in your report: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.

(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test including his/her email address.

(3) For a minimum of 5 years after a performance test is conducted, the owner or operator shall retain and make available, upon request, for inspection by the Administrator the records or results of such performance test and other data needed to determine emissions from an affected source.

(h) *Waiver of performance tests.*

(1) Until a waiver of a performance testing requirement has been granted by the Administrator under this paragraph, the owner or operator of an affected source remains subject to the requirements of this section.

(2) Individual performance tests may be waived upon written application to the Administrator if, in the Administrator's judgment, the source is meeting the relevant standard(s) on a continuous basis, or the source is being operated under an extension of compliance, or the owner or operator has requested an extension of compliance and the Administrator is still considering that request.

(3) *Request to waive a performance test.*

(i) If a request is made for an extension of compliance under § 63.6(i), the application for a waiver of an initial performance test shall accompany the information required for the request for an extension of compliance. If no extension of compliance is requested or if the owner or operator has requested an extension of compliance and the Administrator is still considering that request, the application for a waiver of an initial performance test shall be submitted at least 60 days before the performance test if the site-specific test plan under paragraph (c) of this section is not submitted.

(ii) If an application for a waiver of a subsequent performance test is made, the application may accompany any required compliance progress report, compliance status report, or excess emissions and continuous monitoring system performance report [such as those required

under § 63.6(i), § 63.9(h), and § 63.10(e) or specified in a relevant standard or in the source's title V permit], but it shall be submitted at least 60 days before the performance test if the site-specific test plan required under paragraph (c) of this section is not submitted.

(iii) Any application for a waiver of a performance test shall include information justifying the owner or operator's request for a waiver, such as the technical or economic infeasibility, or the impracticality, of the affected source performing the required test.

(4) *Approval of request to waive performance test.* The Administrator will approve or deny a request for a waiver of a performance test made under paragraph (h)(3) of this section when he/she -

(i) Approves or denies an extension of compliance under § 63.6(i)(8); or

(ii) Approves or disapproves a site-specific test plan under § 63.7(c)(3); or

(iii) Makes a determination of compliance following the submission of a required compliance status report or excess emissions and continuous monitoring systems performance report; or

(iv) Makes a determination of suitable progress towards compliance following the submission of a compliance progress report, whichever is applicable.

(5) Approval of any waiver granted under this section shall not abrogate the Administrator's authority under the Act or in any way prohibit the Administrator from later canceling the waiver. The cancellation will be made only after notice is given to the owner or operator of the affected source.

§ 63.8 Monitoring requirements.

(a) *Applicability.*

(1) The applicability of this section is set out in § 63.1(a)(4).

(2) For the purposes of this part, all CMS required under relevant standards shall be subject to the provisions of this section upon promulgation of performance specifications for CMS as specified in the relevant standard or otherwise by the Administrator.

(3) [Reserved]

(4) Additional monitoring requirements for control devices used to comply with provisions in relevant standards of this part are specified in § 63.11.

(b) *Conduct of monitoring.*

(1) Monitoring shall be conducted as set forth in this section and the relevant standard(s) unless the Administrator -

(i) Specifies or approves the use of minor changes in methodology for the specified monitoring requirements and procedures (see § 63.90(a) for definition); or

(ii) Approves the use of an intermediate or major change or alternative to any monitoring requirements or procedures (see § 63.90(a) for definition).

(iii) Owners or operators with flares subject to § 63.11(b) are not subject to the requirements of this section unless otherwise specified in the relevant standard.

(2) (i) When the emissions from two or more affected sources are combined before being released to the atmosphere, the owner or operator may install an applicable CMS for each emission stream or for the combined emissions streams, provided the monitoring is sufficient to demonstrate compliance with the relevant standard.

(ii) If the relevant standard is a mass emission standard and the emissions from one affected source are released to the atmosphere through more than one point, the owner or operator must install an applicable CMS at each emission point unless the installation of fewer systems is -

(A) Approved by the Administrator; or

(B) Provided for in a relevant standard (e.g., instead of requiring that a CMS be installed at each emission point before the effluents from those points are channeled to a common control device, the standard specifies that only one CMS is required to be installed at the vent of the control device).

(3) When more than one CMS is used to measure the emissions from one affected source (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required for each CMS. However, when one CMS is used as a backup to another CMS, the owner or operator shall report the results from the CMS used to meet the monitoring requirements of this part. If both such CMS are used during a particular reporting period to meet the monitoring requirements of this part, then the owner or operator shall report the results from each CMS for the relevant compliance period.

(c) *Operation and maintenance of continuous monitoring systems.*

(1) The owner or operator of an affected source shall maintain and operate each CMS as specified in this section, or in a relevant standard, and in a manner consistent with good air pollution control practices.

(i) The owner or operator of an affected source must maintain and operate each CMS as specified in § 63.6(e)(1).

(ii) The owner or operator must keep the necessary parts for routine repairs of the affected CMS equipment readily available.

(iii) The owner or operator of an affected source must develop a written startup, shutdown, and malfunction plan for CMS as specified in § 63.6(e)(3).

(2) (i) All CMS must be installed such that representative measures of emissions or process parameters from the affected source are obtained. In addition, CEMS must be located according to procedures contained in the applicable performance specification(s).

(ii) Unless the individual subpart states otherwise, the owner or operator must ensure the read out (that portion of the CMS that provides a visual display or record), or other indication of operation, from any CMS required for compliance with the emission standard is readily accessible on site for operational control or inspection by the operator of the equipment.

(3) All CMS shall be installed, operational, and the data verified as specified in the relevant standard either prior to or in conjunction with conducting performance tests under § 63.7. Verification of

operational status shall, at a minimum, include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system.

(4) Except for system breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high-level calibration drift adjustments, all CMS, including COMS and CEMS, shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(i) All COMS shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(ii) All CEMS for measuring emissions other than opacity shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(5) Unless otherwise approved by the Administrator, minimum procedures for COMS shall include a method for producing a simulated zero opacity condition and an upscale (high-level) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. Such procedures shall provide a system check of all the analyzer's internal optical surfaces and all electronic circuitry, including the lamp and photodetector assembly normally used in the measurement of opacity.

(6) The owner or operator of a CMS that is not a CPMS, which is installed in accordance with the provisions of this part and the applicable CMS performance specification(s), must check the zero (low-level) and high-level calibration drifts at least once daily in accordance with the written procedure specified in the performance evaluation plan developed under paragraphs (e)(3)(i) and (ii) of this section. The zero (low-level) and high-level calibration drifts must be adjusted, at a minimum, whenever the 24-hour zero (low-level) drift exceeds two times the limits of the applicable performance specification(s) specified in the relevant standard. The system shall allow the amount of excess zero (low-level) and high-level drift measured at the 24-hour interval checks to be recorded and quantified whenever specified. For COMS, all optical and instrumental surfaces exposed to the effluent gases must be cleaned prior to performing the zero (low-level) and high-level drift adjustments; the optical surfaces and instrumental surfaces must be cleaned when the cumulative automatic zero compensation, if applicable, exceeds 4 percent opacity. The CPMS must be calibrated prior to use for the purposes of complying with this section. The CPMS must be checked daily for indication that the system is responding. If the CPMS system includes an internal system check, results must be recorded and checked daily for proper operation.

(7) (i) A CMS is out of control if -

(A) The zero (low-level), mid-level (if applicable), or high-level calibration drift (CD) exceeds two times the applicable CD specification in the applicable performance specification or in the relevant standard; or

(B) The CMS fails a performance test audit (e.g., cylinder gas audit), relative accuracy audit, relative accuracy test audit, or linearity test audit; or

(C) The COMS CD exceeds two times the limit in the applicable performance specification in the relevant standard.

(ii) When the CMS is out of control, the owner or operator of the affected source shall take the necessary corrective action and shall repeat all necessary tests which indicate that the system is out of control. The owner or operator shall take corrective action and conduct retesting until the performance requirements are below the applicable limits. The beginning of the out-of-control period is the hour the owner or operator conducts a performance check (e.g., calibration drift) that indicates an exceedance of the performance requirements established under this part. The end of the out-of-control period is the hour following the completion of corrective action and successful demonstration that the system is within the allowable limits. During the period the CMS is out of control, recorded data shall not be used in data averages and calculations, or to meet any data availability requirement established under this part.

(8) The owner or operator of a CMS that is out of control as defined in paragraph (c)(7) of this section shall submit all information concerning out-of-control periods, including start and end dates and hours and descriptions of corrective actions taken, in the excess emissions and continuous monitoring system performance report required in § 63.10(e)(3).

(d) *Quality control program.*

(1) The results of the quality control program required in this paragraph will be considered by the Administrator when he/she determines the validity of monitoring data.

(2) The owner or operator of an affected source that is required to use a CMS and is subject to the monitoring requirements of this section and a relevant standard shall develop and implement a CMS quality control program. As part of the quality control program, the owner or operator shall develop and submit to the Administrator for approval upon request a site-specific performance evaluation test plan for the CMS performance evaluation required in paragraph (e)(3)(i) of this section, according to the procedures specified in paragraph (e). In addition, each quality control program shall include, at a minimum, a written protocol that describes procedures for each of the following operations:

(i) Initial and any subsequent calibration of the CMS;

(ii) Determination and adjustment of the calibration drift of the CMS;

(iii) Preventive maintenance of the CMS, including spare parts inventory;

(iv) Data recording, calculations, and reporting;

(v) Accuracy audit procedures, including sampling and analysis methods; and

(vi) Program of corrective action for a malfunctioning CMS.

(3) The owner or operator shall keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of this part, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, the owner or operator shall keep previous (i.e., superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Administrator, for a period of 5 years after each revision to the plan. Where relevant, e.g., program of corrective action for a malfunctioning CMS, these written procedures may be incorporated as part of the affected source's startup, shutdown, and malfunction plan to avoid duplication of planning and recordkeeping efforts.

(e) *Performance evaluation of continuous monitoring systems* -

(1) *General.* When required by a relevant standard, and at any other time the Administrator may require under section 114 of the Act, the owner or operator of an affected source being monitored shall conduct a performance evaluation of the CMS. Such performance evaluation shall be conducted according to the applicable specifications and procedures described in this section or in the relevant standard.

(2) *Notification of performance evaluation.* The owner or operator shall notify the Administrator in writing of the date of the performance evaluation simultaneously with the notification of the performance test date required under § 63.7(b) or at least 60 days prior to the date the performance evaluation is scheduled to begin if no performance test is required.

(3) (i) *Submission of site-specific performance evaluation test plan.* Before conducting a required CMS performance evaluation, the owner or operator of an affected source shall develop and submit a site-specific performance evaluation test plan to the Administrator for approval upon request. The performance evaluation test plan shall include the evaluation program objectives, an evaluation program summary, the performance evaluation schedule, data quality objectives, and both an internal and external QA program. Data quality objectives are the pre-evaluation expectations of precision, accuracy, and completeness of data.

(ii) The internal QA program shall include, at a minimum, the activities planned by routine operators and analysts to provide an assessment of CMS performance. The external QA program shall include, at a minimum, systems audits that include the opportunity for on-site evaluation by the Administrator of instrument calibration, data validation, sample logging, and documentation of quality control data and field maintenance activities.

(iii) The owner or operator of an affected source shall submit the site-specific performance evaluation test plan to the Administrator (if requested) at least 60 days before the performance test or performance evaluation is scheduled to begin, or on a mutually agreed upon date, and review and approval of the performance evaluation test plan by the Administrator will occur with the review and approval of the site-specific test plan (if review of the site-specific test plan is requested).

(iv) The Administrator may request additional relevant information after the submittal of a site-specific performance evaluation test plan.

(v) In the event that the Administrator fails to approve or disapprove the site-specific performance evaluation test plan within the time period specified in § 63.7(c)(3), the following conditions shall apply:

(A) If the owner or operator intends to demonstrate compliance using the monitoring method(s) specified in the relevant standard, the owner or operator shall conduct the performance evaluation within the time specified in this subpart using the specified method(s);

(B) If the owner or operator intends to demonstrate compliance by using an alternative to a monitoring method specified in the relevant standard, the owner or operator shall refrain from conducting the performance evaluation until the Administrator approves

the use of the alternative method. If the Administrator does not approve the use of the alternative method within 30 days before the performance evaluation is scheduled to begin, the performance evaluation deadlines specified in paragraph (e)(4) of this section may be extended such that the owner or operator shall conduct the performance evaluation within 60 calendar days after the Administrator approves the use of the alternative method. Notwithstanding the requirements in the preceding two sentences, the owner or operator may proceed to conduct the performance evaluation as required in this section (without the Administrator's prior approval of the site-specific performance evaluation test plan) if he/she subsequently chooses to use the specified monitoring method(s) instead of an alternative.

(vi) Neither the submission of a site-specific performance evaluation test plan for approval, nor the Administrator's approval or disapproval of a plan, nor the Administrator's failure to approve or disapprove a plan in a timely manner shall -

(A) Relieve an owner or operator of legal responsibility for compliance with any applicable provisions of this part or with any other applicable Federal, State, or local requirement; or

(B) Prevent the Administrator from implementing or enforcing this part or taking any other action under the Act.

(4) *Conduct of performance evaluation and performance evaluation dates.* The owner or operator of an affected source shall conduct a performance evaluation of a required CMS during any performance test required under § 63.7 in accordance with the applicable performance specification as specified in the relevant standard. Notwithstanding the requirement in the previous sentence, if the owner or operator of an affected source elects to submit COMS data for compliance with a relevant opacity emission standard as provided under § 63.6(h)(7), he/she shall conduct a performance evaluation of the COMS as specified in the relevant standard, before the performance test required under § 63.7 is conducted in time to submit the results of the performance evaluation as specified in paragraph (e)(5)(ii) of this section. If a performance test is not required, or the requirement for a performance test has been waived under § 63.7(h), the owner or operator of an affected source shall conduct the performance evaluation not later than 180 days after the appropriate compliance date for the affected source, as specified in § 63.7(a), or as otherwise specified in the relevant standard.

(5) *Reporting performance evaluation results.*

(i) The owner or operator shall furnish the Administrator a copy of a written report of the results of the performance evaluation containing the information specified in § 63.7(g)(2)(i) through (vi) simultaneously with the results of the performance test required under § 63.7 or within 60 days of completion of the performance evaluation, unless otherwise specified in a relevant standard.

(ii) The owner or operator of an affected source using a COMS to determine opacity compliance during any performance test required under § 63.7 and described in § 63.6(d)(6) shall furnish the Administrator two or, upon request, three copies of a written report of the results of the COMS performance evaluation under this paragraph. The copies shall be provided at least 15 calendar days before the performance test required under § 63.7 is conducted.

(f) *Use of an alternative monitoring method* -

(1) *General.* Until permission to use an alternative monitoring procedure (minor, intermediate, or major changes; see definition in § 63.90(a)) has been granted by the Administrator under this paragraph (f)(1), the owner or operator of an affected source remains subject to the requirements of this section and the relevant standard.

(2) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring methods or procedures of this part including, but not limited to, the following:

(i) Alternative monitoring requirements when installation of a CMS specified by a relevant standard would not provide accurate measurements due to liquid water or other interferences caused by substances within the effluent gases;

(ii) Alternative monitoring requirements when the affected source is infrequently operated;

(iii) Alternative monitoring requirements to accommodate CEMS that require additional measurements to correct for stack moisture conditions;

(iv) Alternative locations for installing CMS when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements;

(v) Alternate methods for converting pollutant concentration measurements to units of the relevant standard;

(vi) Alternate procedures for performing daily checks of zero (low-level) and high-level drift that do not involve use of high-level gases or test cells;

(vii) Alternatives to the American Society for Testing and Materials (ASTM) test methods or sampling procedures specified by any relevant standard;

(viii) Alternative CMS that do not meet the design or performance requirements in this part, but adequately demonstrate a definite and consistent relationship between their measurements and the measurements of opacity by a system complying with the requirements as specified in the relevant standard. The Administrator may require that such demonstration be performed for each affected source; or

(ix) Alternative monitoring requirements when the effluent from a single affected source or the combined effluent from two or more affected sources is released to the atmosphere through more than one point.

(3) If the Administrator finds reasonable grounds to dispute the results obtained by an alternative monitoring method, requirement, or procedure, the Administrator may require the use of a method, requirement, or procedure specified in this section or in the relevant standard. If the results of the specified and alternative method, requirement, or procedure do not agree, the results obtained by the specified method, requirement, or procedure shall prevail.

(4) (i) *Request to use alternative monitoring procedure.* An owner or operator who wishes to use an alternative monitoring procedure must submit an application to the Administrator as described in paragraph (f)(4)(ii) of this section. The application may be submitted at any time provided that the monitoring procedure is not the performance test method used to demonstrate compliance with a

relevant standard or other requirement. If the alternative monitoring procedure will serve as the performance test method that is to be used to demonstrate compliance with a relevant standard, the application must be submitted at least 60 days before the performance evaluation is scheduled to begin and must meet the requirements for an alternative test method under § 63.7(f).

(ii) The application must contain a description of the proposed alternative monitoring system which addresses the four elements contained in the definition of monitoring in § 63.2 and a performance evaluation test plan, if required, as specified in paragraph (e)(3) of this section. In addition, the application must include information justifying the owner or operator's request for an alternative monitoring method, such as the technical or economic infeasibility, or the impracticality, of the affected source using the required method.

(iii) The owner or operator may submit the information required in this paragraph well in advance of the submittal dates specified in paragraph (f)(4)(i) above to ensure a timely review by the Administrator in order to meet the compliance demonstration date specified in this section or the relevant standard.

(iv) Application for minor changes to monitoring procedures, as specified in paragraph (b)(1) of this section, may be made in the site-specific performance evaluation plan.

(5) *Approval of request to use alternative monitoring procedure.*

(i) The Administrator will notify the owner or operator of approval or intention to deny approval of the request to use an alternative monitoring method within 30 calendar days after receipt of the original request and within 30 calendar days after receipt of any supplementary information that is submitted. If a request for a minor change is made in conjunction with site-specific performance evaluation plan, then approval of the plan will constitute approval of the minor change. Before disapproving any request to use an alternative monitoring method, the Administrator will notify the applicant of the Administrator's intention to disapprove the request together with -

(A) Notice of the information and findings on which the intended disapproval is based; and

(B) Notice of opportunity for the owner or operator to present additional information to the Administrator before final action on the request. At the time the Administrator notifies the applicant of his or her intention to disapprove the request, the Administrator will specify how much time the owner or operator will have after being notified of the intended disapproval to submit the additional information.

(ii) The Administrator may establish general procedures and criteria in a relevant standard to accomplish the requirements of paragraph (f)(5)(i) of this section.

(iii) If the Administrator approves the use of an alternative monitoring method for an affected source under paragraph (f)(5)(i) of this section, the owner or operator of such source shall continue to use the alternative monitoring method until he or she receives approval from the Administrator to use another monitoring method as allowed by § 63.8(f).

(6) *Alternative to the relative accuracy test.* An alternative to the relative accuracy test for CEMS specified in a relevant standard may be requested as follows:

(i) *Criteria for approval of alternative procedures.* An alternative to the test method for determining relative accuracy is available for affected sources with emission rates demonstrated to be less than 50 percent of the relevant standard. The owner or operator of an affected source may petition the Administrator under paragraph (f)(6)(ii) of this section to substitute the relative accuracy test in section 7 of Performance Specification 2 with the procedures in section 10 if the results of a performance test conducted according to the requirements in § 63.7, or other tests performed following the criteria in § 63.7, demonstrate that the emission rate of the pollutant of interest in the units of the relevant standard is less than 50 percent of the relevant standard. For affected sources subject to emission limitations expressed as control efficiency levels, the owner or operator may petition the Administrator to substitute the relative accuracy test with the procedures in section 10 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the CEMS is used continuously to determine compliance with the relevant standard.

(ii) *Petition to use alternative to relative accuracy test.* The petition to use an alternative to the relative accuracy test shall include a detailed description of the procedures to be applied, the location and the procedure for conducting the alternative, the concentration or response levels of the alternative relative accuracy materials, and the other equipment checks included in the alternative procedure(s). The Administrator will review the petition for completeness and applicability. The Administrator's determination to approve an alternative will depend on the intended use of the CEMS data and may require specifications more stringent than in Performance Specification 2.

(iii) *Rescission of approval to use alternative to relative accuracy test.* The Administrator will review the permission to use an alternative to the CEMS relative accuracy test and may rescind such permission if the CEMS data from a successful completion of the alternative relative accuracy procedure indicate that the affected source's emissions are approaching the level of the relevant standard. The criterion for reviewing the permission is that the collection of CEMS data shows that emissions have exceeded 70 percent of the relevant standard for any averaging period, as specified in the relevant standard. For affected sources subject to emission limitations expressed as control efficiency levels, the criterion for reviewing the permission is that the collection of CEMS data shows that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for any averaging period, as specified in the relevant standard. The owner or operator of the affected source shall maintain records and determine the level of emissions relative to the criterion for permission to use an alternative for relative accuracy testing. If this criterion is exceeded, the owner or operator shall notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increased emissions. The Administrator will review the notification and may rescind permission to use an alternative and require the owner or operator to conduct a relative accuracy test of the CEMS as specified in section 7 of Performance Specification 2. The Administrator will review the notification and may rescind permission to use an alternative and require the owner or operator to conduct a relative accuracy test of the CEMS as specified in section 8.4 of Performance Specification 2.

(g) *Reduction of monitoring data.*

(1) The owner or operator of each CMS must reduce the monitoring data as specified in paragraphs (g)(1) through (5) of this section.

(2) The owner or operator of each COMS shall reduce all data to 6-minute averages calculated from 36 or more data points equally spaced over each 6-minute period. Data from CEMS for measurement other than opacity, unless otherwise specified in the relevant standard, shall be reduced to 1-hour averages computed from four or more data points equally spaced over each 1-hour period, except during periods when calibration, quality assurance, or maintenance activities pursuant to provisions of this part are being performed. During these periods, a valid hourly average shall consist of at least two data points with each representing a 15-minute period. Alternatively, an arithmetic or integrated 1-hour average of CEMS data may be used. Time periods for averaging are defined in § 63.2.

(3) The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant).

(4) All emission data shall be converted into units of the relevant standard for reporting purposes using the conversion procedures specified in that standard. After conversion into units of the relevant standard, the data may be rounded to the same number of significant digits as used in that standard to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).

(5) Monitoring data recorded during periods of unavoidable CMS breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high-level adjustments must not be included in any data average computed under this part. For the owner or operator complying with the requirements of § 63.10(b)(2)(vii)(A) or (B), data averages must include any data recorded during periods of monitor breakdown or malfunction.

§ 63.9 Notification requirements.

(a) *Applicability and general information.*

(1) The applicability of this section is set out in § 63.1(a)(4).

(2) For affected sources that have been granted an extension of compliance under subpart D of this part, the requirements of this section do not apply to those sources while they are operating under such compliance extensions.

(3) If any State requires a notice that contains all the information required in a notification listed in this section, the owner or operator may send the Administrator a copy of the notice sent to the State to satisfy the requirements of this section for that notification.

(4) (i) Before a State has been delegated the authority to implement and enforce notification requirements established under this part, the owner or operator of an affected source in such State subject to such requirements shall submit notifications to the appropriate Regional Office of the EPA (to the attention of the Director of the Division indicated in the list of the EPA Regional Offices in § 63.13).

(ii) After a State has been delegated the authority to implement and enforce notification requirements established under this part, the owner or operator of an affected source in such State subject to such requirements shall submit notifications to the delegated State authority (which may be the same as the permitting authority). In addition, if the delegated (permitting)

authority is the State, the owner or operator shall send a copy of each notification submitted to the State to the appropriate Regional Office of the EPA, as specified in paragraph (a)(4)(i) of this section. The Regional Office may waive this requirement for any notifications at its discretion.

(b) *Initial notifications.*

(1) (i) The requirements of this paragraph apply to the owner or operator of an affected source when such source becomes subject to a relevant standard.

(ii) If an area source subsequently becomes a major source that is subject to the emission standard or other requirement, such source shall be subject to the notification requirements of this section. Area sources previously subject to major source requirements that become major sources again are also subject to the notification requirements of this paragraph and must submit the notification according to the requirements of paragraph (k) of this section.

(iii) Affected sources that are required under this paragraph to submit an initial notification may use the application for approval of construction or reconstruction under § 63.5(d) of this subpart, if relevant, to fulfill the initial notification requirements of this paragraph.

(2) The owner or operator of an affected source that has an initial startup before the effective date of a relevant standard under this part shall notify the Administrator in writing that the source is subject to the relevant standard. The notification, which shall be submitted not later than 120 calendar days after the effective date of the relevant standard (or within 120 calendar days after the source becomes subject to the relevant standard), shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (i.e., physical location) of the affected source;

(iii) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;

(iv) A brief description of the nature, size, design, and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted; and

(v) A statement of whether the affected source is a major source or an area source.

(3) [Reserved]

(4) The owner or operator of a new or reconstructed major affected source for which an application for approval of construction or reconstruction is required under § 63.5(d) must provide the following information in writing to the Administrator:

(i) A notification of intention to construct a new major-emitting affected source, reconstruct a major-emitting affected source, or reconstruct a major source such that the source becomes a major-emitting affected source with the application for approval of construction or reconstruction as specified in § 63.5(d)(1)(i); and

(ii)-(iv) [Reserved]

(v) A notification of the actual date of startup of the source, delivered or postmarked within 15 calendar days after that date.

(5) The owner or operator of a new or reconstructed affected source for which an application for approval of construction or reconstruction is not required under § 63.5(d) must provide the following information in writing to the Administrator:

(i) A notification of intention to construct a new affected source, reconstruct an affected source, or reconstruct a source such that the source becomes an affected source, and

(ii) A notification of the actual date of startup of the source, delivered or postmarked within 15 calendar days after that date.

(iii) Unless the owner or operator has requested and received prior permission from the Administrator to submit less than the information in § 63.5(d), the notification must include the information required on the application for approval of construction or reconstruction as specified in § 63.5(d)(1)(i).

(c) *Request for extension of compliance.* If the owner or operator of an affected source cannot comply with a relevant standard by the applicable compliance date for that source, or if the owner or operator has installed BACT or technology to meet LAER consistent with § 63.6(i)(5) of this subpart, he/she may submit to the Administrator (or the State with an approved permit program) a request for an extension of compliance as specified in § 63.6(i)(4) through § 63.6(i)(6).

(d) *Notification that source is subject to special compliance requirements.* An owner or operator of a new source that is subject to special compliance requirements as specified in § 63.6(b)(3) and § 63.6(b)(4) shall notify the Administrator of his/her compliance obligations not later than the notification dates established in paragraph (b) of this section for new sources that are not subject to the special provisions.

(e) *Notification of performance test.* The owner or operator of an affected source shall notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin to allow the Administrator to review and approve the site-specific test plan required under § 63.7(c), if requested by the Administrator, and to have an observer present during the test.

(f) *Notification of opacity and visible emission observations.* The owner or operator of an affected source shall notify the Administrator in writing of the anticipated date for conducting the opacity or visible emission observations specified in § 63.6(h)(5), if such observations are required for the source by a relevant standard. The notification shall be submitted with the notification of the performance test date, as specified in paragraph (e) of this section, or if no performance test is required or visibility or other conditions prevent the opacity or visible emission observations from being conducted concurrently with the initial performance test required under § 63.7, the owner or operator shall deliver or postmark the notification not less than 30 days before the opacity or visible emission observations are scheduled to take place.

(g) *Additional notification requirements for sources with continuous monitoring systems.* The owner or operator of an affected source required to use a CMS by a relevant standard shall furnish the Administrator written notification as follows:

(1) A notification of the date the CMS performance evaluation under § 63.8(e) is scheduled to begin, submitted simultaneously with the notification of the performance test date required under § 63.7(b). If no performance test is required, or if the requirement to conduct a performance test has been

waived for an affected source under § 63.7(h), the owner or operator shall notify the Administrator in writing of the date of the performance evaluation at least 60 calendar days before the evaluation is scheduled to begin;

(2) A notification that COMS data results will be used to determine compliance with the applicable opacity emission standard during a performance test required by § 63.7 in lieu of Method 9 or other opacity emissions test method data, as allowed by § 63.6(h)(7)(ii), if compliance with an opacity emission standard is required for the source by a relevant standard. The notification shall be submitted at least 60 calendar days before the performance test is scheduled to begin; and

(3) A notification that the criterion necessary to continue use of an alternative to relative accuracy testing, as provided by § 63.8(f)(6), has been exceeded. The notification shall be delivered or postmarked not later than 10 days after the occurrence of such exceedance, and it shall include a description of the nature and cause of the increased emissions.

(h) *Notification of compliance status.*

(1) The requirements of paragraphs (h)(2) through (h)(4) of this section apply when an affected source becomes subject to a relevant standard.

(2) (i) Before a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this part, the owner or operator of such source shall submit to the Administrator a notification of compliance status, signed by the responsible official who shall certify its accuracy, attesting to whether the source has complied with the relevant standard. The notification shall list -

(A) The methods that were used to determine compliance;

(B) The results of any performance tests, opacity or visible emission observations, continuous monitoring system (CMS) performance evaluations, and/or other monitoring procedures or methods that were conducted;

(C) The methods that will be used for determining continuing compliance, including a description of monitoring and reporting requirements and test methods;

(D) The type and quantity of hazardous air pollutants emitted by the source (or surrogate pollutants if specified in the relevant standard), reported in units and averaging times and in accordance with the test methods specified in the relevant standard;

(E) If the relevant standard applies to both major and area sources, an analysis demonstrating whether the affected source is a major source (using the emissions data generated for this notification);

(F) A description of the air pollution control equipment (or method) for each emission point, including each control device (or method) for each hazardous air pollutant and the control efficiency (percent) for each control device (or method); and

(G) A statement by the owner or operator of the affected existing, new, or reconstructed source as to whether the source has complied with the relevant standard or other requirements.

(ii) The notification must be sent before the close of business on the 60th day following the completion of the relevant compliance demonstration activity specified in the relevant standard (unless a different reporting period is specified in the standard, in which case the letter must be sent before the close of business on the day the report of the relevant testing or monitoring results is required to be delivered or postmarked). For example, the notification shall be sent before close of business on the 60th (or other required) day following completion of the initial performance test and again before the close of business on the 60th (or other required) day following the completion of any subsequent required performance test. If no performance test is required but opacity or visible emission observations are required to demonstrate compliance with an opacity or visible emission standard under this part, the notification of compliance status shall be sent before close of business on the 30th day following the completion of opacity or visible emission observations. Notifications may be combined as long as the due date requirement for each notification is met.

(3) After a title V permit has been issued to the owner or operator of an affected source, the owner or operator of such source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this part. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this part, the owner or operator of such source shall submit the notification of compliance status to the appropriate permitting authority following completion of the relevant compliance demonstration activity specified in the relevant standard.

(4) [Reserved]

(5) If an owner or operator of an affected source submits estimates or preliminary information in the application for approval of construction or reconstruction required in § 63.5(d) in place of the actual emissions data or control efficiencies required in paragraphs (d)(1)(ii)(H) and (d)(2) of § 63.5, the owner or operator shall submit the actual emissions data and other correct information as soon as available but no later than with the initial notification of compliance status required in this section.

(6) Advice on a notification of compliance status may be obtained from the Administrator.

(i) *Adjustment to time periods or postmark deadlines for submittal and review of required communications.*

(1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (i)(2) and (i)(3) of this section, the owner or operator of an affected source remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (i)(2) and (i)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall

include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

(j) *Change in information already provided.* Any change in the information already provided under this section shall be provided to the Administrator within 15 calendar days after the change. The owner or operator of a major source that reclassifies to area source status is also subject to the notification requirements of this paragraph. The owner or operator may use the application for reclassification with the regulatory authority (*e.g.,* permit application) to fulfill the requirements of this paragraph. A source which reclassified after January 25, 2018, and before January 19, 2021, and has not yet provided the notification of a change in information is required to provide such notification no later than February 2, 2021, according to the requirements of paragraph (k) of this section. Beginning January 19, 2021, the owner or operator of a major source that reclassifies to area source status must submit the notification according to the requirements of paragraph (k) of this section. A notification of reclassification must contain the following information:

(1) The name and address of the owner or operator;

(2) The address (*i.e.,* physical location) of the affected source;

(3) An identification of the standard being reclassified from and to (if applicable); and

(4) Date of effectiveness of the reclassification.

(k) *Electronic submission of notifications or reports.* If you are required to submit notifications or reports following the procedure specified in this paragraph (k), you must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The notification or report must be submitted by the deadline specified. The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Anything submitted using CEDRI cannot later be claimed to be CBI. Although we do not expect persons to assert a claim of CBI, if persons wish to assert a CBI, submit a complete notification or report, including information claimed to be CBI, to the EPA. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph (k). All CBI claims must be asserted at the time of submission. Furthermore, under section 114(c) of the Act emissions data is not entitled to confidential treatment and requires EPA to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(1) If you are required to electronically submit a notification or report by this paragraph (k) through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with the electronic submittal requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (k)(1)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required notification or report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning 5 business days prior to the date that the notification or report is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in submitting beyond the regulatory deadline to EPA system outage;

(C) Measures taken or to be taken to minimize the delay in submitting; and

(D) The date by which you propose to submit, or if you have already met the electronic submittal requirement in this paragraph (k) at the time of the notification, the date you submitted the notification or report.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the notification or report must be submitted electronically as soon as possible after the outage is resolved.

(2) If you are required to electronically submit a notification or report by this paragraph (k) through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with the electronic submittal requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (k)(2)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a notification or report electronically within the time period prescribed. Examples of such events are acts of nature

(*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in submitting through CEDRI.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) Measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to submit the notification or report, or if you have already met the electronic submittal requirement in this paragraph (k) at the time of the notification, the date you submitted the notification or report.

(iv) The decision to accept the claim of force majeure and allow an extension to the submittal deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 63.10 Recordkeeping and reporting requirements.

(a) *Applicability and general information.*

(1) The applicability of this section is set out in § 63.1(a)(4).

(2) For affected sources that have been granted an extension of compliance under subpart D of this part, the requirements of this section do not apply to those sources while they are operating under such compliance extensions.

(3) If any State requires a report that contains all the information required in a report listed in this section, an owner or operator may send the Administrator a copy of the report sent to the State to satisfy the requirements of this section for that report.

(4) (i) Before a State has been delegated the authority to implement and enforce recordkeeping and reporting requirements established under this part, the owner or operator of an affected source in such State subject to such requirements shall submit reports to the appropriate Regional Office of the EPA (to the attention of the Director of the Division indicated in the list of the EPA Regional Offices in § 63.13).

(ii) After a State has been delegated the authority to implement and enforce recordkeeping and reporting requirements established under this part, the owner or operator of an affected source in such State subject to such requirements shall submit reports to the delegated State authority (which may be the same as the permitting authority). In addition, if the delegated (permitting) authority is the State, the owner or operator shall send a copy of each report submitted to the State to the appropriate Regional Office of the EPA, as specified in paragraph

(a)(4)(i) of this section. The Regional Office may waive this requirement for any reports at its discretion.

(5) If an owner or operator of an affected source in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such source under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. For each relevant standard established pursuant to section 112 of the Act, the allowance in the previous sentence applies in each State beginning 1 year after the affected source's compliance date for that standard. Procedures governing the implementation of this provision are specified in § 63.9(i).

(6) If an owner or operator supervises one or more stationary sources affected by more than one standard established pursuant to section 112 of the Act, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State permitting authority) a common schedule on which periodic reports required for each source shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the latest compliance date for any relevant standard established pursuant to section 112 of the Act for any such affected source(s). Procedures governing the implementation of this provision are specified in § 63.9(i).

(7) If an owner or operator supervises one or more stationary sources affected by standards established pursuant to section 112 of the Act (as amended November 15, 1990) and standards set under part 60, part 61, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State permitting authority) a common schedule on which periodic reports required by each relevant (i.e., applicable) standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the relevant section 112 standard, or 1 year after the stationary source is required to be in compliance with the applicable part 60 or part 61 standard, whichever is latest. Procedures governing the implementation of this provision are specified in § 63.9(i).

(b) *General recordkeeping requirements.*

(1) The owner or operator of an affected source subject to the provisions of this part shall maintain files of all information (including all reports and notifications) required by this part recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

(2) The owner or operator of an affected source subject to the provisions of this part shall maintain relevant records for such source of -

(i) The occurrence and duration of each startup or shutdown when the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards;

(ii) The occurrence and duration of each malfunction of operation (i.e., process equipment) or the required air pollution control and monitoring equipment;

(iii) All required maintenance performed on the air pollution control and monitoring equipment;

(iv) (A) Actions taken during periods of startup or shutdown when the source exceeded applicable emission limitations in a relevant standard and when the actions taken are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan (see § 63.6(e)(3)); or

(B) Actions taken during periods of malfunction (including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation) when the actions taken are different from the procedures specified in the affected source's startup, shutdown, and malfunction plan (see § 63.6(e)(3));

(v) All information necessary, including actions taken, to demonstrate conformance with the affected source's startup, shutdown, and malfunction plan (see § 63.6(e)(3)) when all actions taken during periods of startup or shutdown (and the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards), and malfunction (including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation) are consistent with the procedures specified in such plan. (The information needed to demonstrate conformance with the startup, shutdown, and malfunction plan may be recorded using a “checklist,” or some other effective form of recordkeeping, in order to minimize the recordkeeping burden for conforming events);

(vi) Each period during which a CMS is malfunctioning or inoperative (including out-of-control periods);

(vii) All required measurements needed to demonstrate compliance with a relevant standard (including, but not limited to, 15-minute averages of CMS data, raw performance testing measurements, and raw performance evaluation measurements, that support data that the source is required to report);

(A) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (b)(2)(vii) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(B) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and

where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (b)(2)(vii) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(C) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (b)(2)(vii), if the administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(viii) All results of performance tests, CMS performance evaluations, and opacity and visible emission observations;

(ix) All measurements as may be necessary to determine the conditions of performance tests and performance evaluations;

(x) All CMS calibration checks;

(xi) All adjustments and maintenance performed on CMS;

(xii) Any information demonstrating whether a source is meeting the requirements for a waiver of recordkeeping or reporting requirements under this part, if the source has been granted a waiver under paragraph (f) of this section;

(xiii) All emission levels relative to the criterion for obtaining permission to use an alternative to the relative accuracy test, if the source has been granted such permission under § 63.8(f)(6); and

(xiv) All documentation supporting initial notifications and notifications of compliance status under § 63.9.

(3) If an owner or operator determines that his or her existing or new stationary source is in the source category regulated by a standard established pursuant to section 112 of the Act, but that source is not subject to the relevant standard (or other requirement established under this part) because of enforceable limitations on the source's potential to emit, or the source otherwise qualifies for an exclusion, the owner or operator must keep a record of the applicability determination. The applicability determination must be kept on site at the source for a period of 5 years after the determination, or until the source changes its operations to become an affected source subject to the relevant standard (or other requirement established under this part), whichever comes first if the determination is made prior to January 19, 2021. The applicability determination must be kept until the source changes its operations to become an affected source subject to the relevant standard (or other requirement established under this part) if the determination was made on or after January 19, 2021. The record of the applicability determination must be signed by the person making the determination and include an emissions analysis (or other information) that demonstrates the owner or operator's conclusion that the source is unaffected (*e.g.,* because the source is an area source). The analysis (or other information) must be sufficiently detailed to allow the Administrator to make an applicability finding for the source with regard to the relevant standard or other requirement. If

applicable, the analysis must be performed in accordance with requirements established in relevant subparts of this part for this purpose for particular categories of stationary sources. If relevant, the analysis should be performed in accordance with EPA guidance materials published to assist sources in making applicability determinations under section 112 of the Act, if any. The requirements to determine applicability of a standard under § 63.1(b)(3) and to record the results of that determination under this paragraph (b)(3) of this section shall not by themselves create an obligation for the owner or operator to obtain a title V permit.

(c) *Additional recordkeeping requirements for sources with continuous monitoring systems.* In addition to complying with the requirements specified in paragraphs (b)(1) and (b)(2) of this section, the owner or operator of an affected source required to install a CMS by a relevant standard shall maintain records for such source of -

(1) All required CMS measurements (including monitoring data recorded during unavoidable CMS breakdowns and out-of-control periods);

(2)-(4) [Reserved]

(5) The date and time identifying each period during which the CMS was inoperative except for zero (low-level) and high-level checks;

(6) The date and time identifying each period during which the CMS was out of control, as defined in § 63.8(c)(7);

(7) The specific identification (i.e., the date and time of commencement and completion) of each period of excess emissions and parameter monitoring exceedances, as defined in the relevant standard(s), that occurs during startups, shutdowns, and malfunctions of the affected source;

(8) The specific identification (i.e., the date and time of commencement and completion) of each time period of excess emissions and parameter monitoring exceedances, as defined in the relevant standard(s), that occurs during periods other than startups, shutdowns, and malfunctions of the affected source;

(9) [Reserved]

(10) The nature and cause of any malfunction (if known);

(11) The corrective action taken or preventive measures adopted;

(12) The nature of the repairs or adjustments to the CMS that was inoperative or out of control;

(13) The total process operating time during the reporting period; and

(14) All procedures that are part of a quality control program developed and implemented for CMS under § 63.8(d).

(15) In order to satisfy the requirements of paragraphs (c)(10) through (c)(12) of this section and to avoid duplicative recordkeeping efforts, the owner or operator may use the affected source's startup, shutdown, and malfunction plan or records kept to satisfy the recordkeeping requirements of the startup, shutdown, and malfunction plan specified in § 63.6(e), provided that such plan and records adequately address the requirements of paragraphs (c)(10) through (c)(12).

(d) *General reporting requirements.*

(1) Notwithstanding the requirements in this paragraph or paragraph (e) of this section, and except as provided in § 63.16, the owner or operator of an affected source subject to reporting requirements under this part shall submit reports to the Administrator in accordance with the reporting requirements in the relevant standard(s).

(2) *Reporting results of performance tests.* Before a title V permit has been issued to the owner or operator of an affected source, the owner or operator shall report the results of any performance test under § 63.7 to the Administrator. After a title V permit has been issued to the owner or operator of an affected source, the owner or operator shall report the results of a required performance test to the appropriate permitting authority. The owner or operator of an affected source shall report the results of the performance test to the Administrator (or the State with an approved permit program) before the close of business on the 60th day following the completion of the performance test, unless specified otherwise in a relevant standard or as approved otherwise in writing by the Administrator. The results of the performance test shall be submitted as part of the notification of compliance status required under § 63.9(h).

(3) *Reporting results of opacity or visible emission observations.* The owner or operator of an affected source required to conduct opacity or visible emission observations by a relevant standard shall report the opacity or visible emission results (produced using Test Method 9 or Test Method 22, or an alternative to these test methods) along with the results of the performance test required under § 63.7. If no performance test is required, or if visibility or other conditions prevent the opacity or visible emission observations from being conducted concurrently with the performance test required under § 63.7, the owner or operator shall report the opacity or visible emission results before the close of business on the 30th day following the completion of the opacity or visible emission observations.

(4) *Progress reports.* The owner or operator of an affected source who is required to submit progress reports as a condition of receiving an extension of compliance under § 63.6(i) shall submit such reports to the Administrator (or the State with an approved permit program) by the dates specified in the written extension of compliance.

(5) (i) *Periodic startup, shutdown, and malfunction reports.* If actions taken by an owner or operator during a startup or shutdown (and the startup or shutdown causes the source to exceed any applicable emission limitation in the relevant emission standards), or malfunction of an affected source (including actions taken to correct a malfunction) are consistent with the procedures specified in the source's startup, shutdown, and malfunction plan (see § 63.6(e)(3)), the owner or operator shall state such information in a startup, shutdown, and malfunction report. Actions taken to minimize emissions during such startups, shutdowns, and malfunctions shall be summarized in the report and may be done in checklist form; if actions taken are the same for each event, only one checklist is necessary. Such a report shall also include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. Reports shall only be required if a startup or shutdown caused the source to exceed any applicable emission limitation in the relevant emission standards, or if a malfunction occurred during the reporting period. The startup, shutdown, and malfunction report shall consist of a letter, containing the name, title, and signature of the owner or operator or other responsible official who is certifying its accuracy, that shall be submitted to the Administrator semiannually (or on a more frequent basis if specified otherwise in a relevant standard or as

established otherwise by the permitting authority in the source's title V permit). The startup, shutdown, and malfunction report shall be delivered or postmarked by the 30th day following the end of each calendar half (or other calendar reporting period, as appropriate). If the owner or operator is required to submit excess emissions and continuous monitoring system performance (or other periodic) reports under this part, the startup, shutdown, and malfunction reports required under this paragraph may be submitted simultaneously with the excess emissions and continuous monitoring system performance (or other) reports. If startup, shutdown, and malfunction reports are submitted with excess emissions and continuous monitoring system performance (or other periodic) reports, and the owner or operator receives approval to reduce the frequency of reporting for the latter under paragraph (e) of this section, the frequency of reporting for the startup, shutdown, and malfunction reports also may be reduced if the Administrator does not object to the intended change. The procedures to implement the allowance in the preceding sentence shall be the same as the procedures specified in paragraph (e)(3) of this section.

(ii) *Immediate startup, shutdown, and malfunction reports.* Notwithstanding the allowance to reduce the frequency of reporting for periodic startup, shutdown, and malfunction reports under paragraph (d)(5)(i) of this section, any time an action taken by an owner or operator during a startup or shutdown that caused the source to exceed any applicable emission limitation in the relevant emission standards, or malfunction (including actions taken to correct a malfunction) is not consistent with the procedures specified in the affected source's startup, shutdown, and malfunction plan, the owner or operator shall report the actions taken for that event within 2 working days after commencing actions inconsistent with the plan followed by a letter within 7 working days after the end of the event. The immediate report required under this paragraph (d)(5)(ii) shall consist of a telephone call (or facsimile (FAX) transmission) to the Administrator within 2 working days after commencing actions inconsistent with the plan, and it shall be followed by a letter, delivered or postmarked within 7 working days after the end of the event, that contains the name, title, and signature of the owner or operator or other responsible official who is certifying its accuracy, explaining the circumstances of the event, the reasons for not following the startup, shutdown, and malfunction plan, describing all excess emissions and/or parameter monitoring exceedances which are believed to have occurred (or could have occurred in the case of malfunctions), and actions taken to minimize emissions in conformance with § 63.6(e)(1)(i). Notwithstanding the requirements of the previous sentence, after the effective date of an approved permit program in the State in which an affected source is located, the owner or operator may make alternative reporting arrangements, in advance, with the permitting authority in that State. Procedures governing the arrangement of alternative reporting requirements under this paragraph (d)(5)(ii) are specified in § 63.9(i).

(e) *Additional reporting requirements for sources with continuous monitoring systems* -

(1) *General.* When more than one CEMS is used to measure the emissions from one affected source (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required for each CEMS.

(2) *Reporting results of continuous monitoring system performance evaluations.*

(i) The owner or operator of an affected source required to install a CMS by a relevant standard shall furnish the Administrator a copy of a written report of the results of the CMS performance

evaluation, as required under § 63.8(e), simultaneously with the results of the performance test required under § 63.7, unless otherwise specified in the relevant standard.

(ii) The owner or operator of an affected source using a COMS to determine opacity compliance during any performance test required under § 63.7 and described in § 63.6(d)(6) shall furnish the Administrator two or, upon request, three copies of a written report of the results of the COMS performance evaluation conducted under § 63.8(e). The copies shall be furnished at least 15 calendar days before the performance test required under § 63.7 is conducted.

(3) *Excess emissions and continuous monitoring system performance report and summary report.*

(i) Excess emissions and parameter monitoring exceedances are defined in relevant standards. The owner or operator of an affected source required to install a CMS by a relevant standard shall submit an excess emissions and continuous monitoring system performance report and/or a summary report to the Administrator semiannually, except when -

(A) More frequent reporting is specifically required by a relevant standard;

(B) The Administrator determines on a case-by-case basis that more frequent reporting is necessary to accurately assess the compliance status of the source; or

(C) [Reserved]

(D) The affected source is complying with the Performance Track Provisions of § 63.16, which allows less frequent reporting.

(ii) *Request to reduce frequency of excess emissions and continuous monitoring system performance reports.* Notwithstanding the frequency of reporting requirements specified in paragraph (e)(3)(i) of this section, an owner or operator who is required by a relevant standard to submit excess emissions and continuous monitoring system performance (and summary) reports on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(A) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected source's excess emissions and continuous monitoring system performance reports continually demonstrate that the source is in compliance with the relevant standard;

(B) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the relevant standard; and

(C) The Administrator does not object to a reduced frequency of reporting for the affected source, as provided in paragraph (e)(3)(iii) of this section.

(iii) The frequency of reporting of excess emissions and continuous monitoring system performance (and summary) reports required to comply with a relevant standard may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the 5-year recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and

maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(iv) As soon as CMS data indicate that the source is not in compliance with any emission limitation or operating parameter specified in the relevant standard, the frequency of reporting shall revert to the frequency specified in the relevant standard, and the owner or operator shall submit an excess emissions and continuous monitoring system performance (and summary) report for the noncomplying emission points at the next appropriate reporting period following the noncomplying event. After demonstrating ongoing compliance with the relevant standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard, as provided for in paragraphs (e)(3)(ii) and (e)(3)(iii) of this section.

(v) *Content and submittal dates for excess emissions and monitoring system performance reports.* All excess emissions and monitoring system performance reports and all summary reports, if required, shall be delivered or postmarked by the 30th day following the end of each calendar half or quarter, as appropriate. Written reports of excess emissions or exceedances of process or control system parameters shall include all the information required in paragraphs (c)(5) through (c)(13) of this section, in §§ 63.8(c)(7) and 63.8(c)(8), and in the relevant standard, and they shall contain the name, title, and signature of the responsible official who is certifying the accuracy of the report. When no excess emissions or exceedances of a parameter have occurred, or a CMS has not been inoperative, out of control, repaired, or adjusted, such information shall be stated in the report.

(vi) *Summary report.* As required under paragraphs (e)(3)(vii) and (e)(3)(viii) of this section, one summary report shall be submitted for the hazardous air pollutants monitored at each affected source (unless the relevant standard specifies that more than one summary report is required, e.g., one summary report for each hazardous air pollutant monitored). The summary report shall be entitled “Summary Report - Gaseous and Opacity Excess Emission and Continuous Monitoring System Performance” and shall contain the following information:

(A) The company name and address of the affected source;

(B) An identification of each hazardous air pollutant monitored at the affected source;

(C) The beginning and ending dates of the reporting period;

(D) A brief description of the process units;

(E) The emission and operating parameter limitations specified in the relevant standard(s);

(F) The monitoring equipment manufacturer(s) and model number(s);

(G) The date of the latest CMS certification or audit;

(H) The total operating time of the affected source during the reporting period;

(I) An emission data summary (or similar summary if the owner or operator monitors control system parameters), including the total duration of excess emissions during the reporting period (recorded in minutes for opacity and hours for gases), the total duration of excess emissions expressed as a percent of the total source operating time during that reporting period, and a breakdown of the total duration of excess emissions during the reporting period into those that are due to startup/shutdown, control equipment problems, process problems, other known causes, and other unknown causes;

(J) A CMS performance summary (or similar summary if the owner or operator monitors control system parameters), including the total CMS downtime during the reporting period (recorded in minutes for opacity and hours for gases), the total duration of CMS downtime expressed as a percent of the total source operating time during that reporting period, and a breakdown of the total CMS downtime during the reporting period into periods that are due to monitoring equipment malfunctions, nonmonitoring equipment malfunctions, quality assurance/quality control calibrations, other known causes, and other unknown causes;

(K) A description of any changes in CMS, processes, or controls since the last reporting period;

(L) The name, title, and signature of the responsible official who is certifying the accuracy of the report; and

(M) The date of the report.

(vii) If the total duration of excess emissions or process or control system parameter exceedances for the reporting period is less than 1 percent of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report shall be submitted, and the full excess emissions and continuous monitoring system performance report need not be submitted unless required by the Administrator.

(viii) If the total duration of excess emissions or process or control system parameter exceedances for the reporting period is 1 percent or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, both the summary report and the excess emissions and continuous monitoring system performance report shall be submitted.

(4) *Reporting continuous opacity monitoring system data produced during a performance test.* The owner or operator of an affected source required to use a COMS shall record the monitoring data produced during a performance test required under § 63.7 and shall furnish the Administrator a written report of the monitoring results. The report of COMS data shall be submitted simultaneously with the report of the performance test results required in paragraph (d)(2) of this section.

(f) *Waiver of recordkeeping or reporting requirements.*

(1) Until a waiver of a recordkeeping or reporting requirement has been granted by the Administrator under this paragraph, the owner or operator of an affected source remains subject to the requirements of this section.

(2) Recordkeeping or reporting requirements may be waived upon written application to the Administrator if, in the Administrator's judgment, the affected source is achieving the relevant standard(s), or the source is operating under an extension of compliance, or the owner or operator has requested an extension of compliance and the Administrator is still considering that request.

(3) If an application for a waiver of recordkeeping or reporting is made, the application shall accompany the request for an extension of compliance under § 63.6(i), any required compliance progress report or compliance status report required under this part (such as under §§ 63.6(i) and 63.9(h)) or in the source's title V permit, or an excess emissions and continuous monitoring system performance report required under paragraph (e) of this section, whichever is applicable. The application shall include whatever information the owner or operator considers useful to convince the Administrator that a waiver of recordkeeping or reporting is warranted.

(4) The Administrator will approve or deny a request for a waiver of recordkeeping or reporting requirements under this paragraph when he/she -

(i) Approves or denies an extension of compliance; or

(ii) Makes a determination of compliance following the submission of a required compliance status report or excess emissions and continuous monitoring systems performance report; or

(iii) Makes a determination of suitable progress towards compliance following the submission of a compliance progress report, whichever is applicable.

(5) A waiver of any recordkeeping or reporting requirement granted under this paragraph may be conditioned on other recordkeeping or reporting requirements deemed necessary by the Administrator.

(6) Approval of any waiver granted under this section shall not abrogate the Administrator's authority under the Act or in any way prohibit the Administrator from later canceling the waiver. The cancellation will be made only after notice is given to the owner or operator of the affected source.

§ 63.11 Control device and work practice requirements.

(a) *Applicability.*

(1) The applicability of this section is set out in § 63.1(a)(4).

(2) This section contains requirements for control devices used to comply with applicable subparts of this part. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(3) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(b) *Flares.*

(1) Owners or operators using flares to comply with the provisions of this part shall monitor these control devices to assure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators using flares shall monitor these control devices.

(2) Flares shall be steam-assisted, air-assisted, or non-assisted.

(3) Flares shall be operated at all times when emissions may be vented to them.

(4) Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. Test Method 22 in appendix A of part 60 of this chapter shall be used to determine the compliance of flares with the visible emission provisions of this part. The observation period is 2 hours and shall be used according to Method 22.

(5) Flares shall be operated with a flame present at all times. The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(6) An owner/operator has the choice of adhering to the heat content specifications in paragraph (b)(6)(ii) of this section, and the maximum tip velocity specifications in paragraph (b)(7) or (b)(8) of this section, or adhering to the requirements in paragraph (b)(6)(i) of this section.

(i) (A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume) or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity V_{max}, as determined by the following equation:

$V_{max} = (X_{H2} - K_1) * K_2$

Where:

V_{max} = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in § 63.14).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (b)(7)(i) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted at 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted at 7.45 M/scm (200 Btu/scf) or greater if the flares is non-assisted. The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C.

K = Constant =

$$1.740 \times 10^{-7} \left(\frac{1}{\text{ppmv}} \right) \left(\frac{\text{g-mole}}{\text{scm}} \right) \left(\frac{\text{MJ}}{\text{kcal}} \right)$$

where the standard temperature for (g-mole/scm) is 20 °C.

C_i = Concentration of sample component i in ppmv on a wet basis, as measured for organics by Test Method 18 and measured for hydrogen and carbon monoxide by American Society for Testing and Materials (ASTM) D1946-77 or 90 (Reapproved 1994) (incorporated by reference as specified in § 63.14).

H_i = Net heat of combustion of sample component i, kcal/g-mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in § 63.14) if published values are not available or cannot be calculated.

n = Number of sample components.

(7) (i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (b)(7)(ii) and (b)(7)(iii) of this section. The actual exit velocity of a flare shall be determined by dividing by the volumetric flow rate of gas being combusted (in units of emission standard temperature and pressure), as determined by Test Method 2, 2A, 2C, or 2D in appendix A to 40 CFR part 60 of this chapter, as appropriate, by the unobstructed (free) cross-sectional area of the flare tip.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the method specified in paragraph (b)(7)(i) of this section, equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec), are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the method specified in paragraph (b)(7)(i) of this section, less than the velocity V_{max}, as determined by the method specified in this paragraph, but less than 122 m/sec (400 ft/sec) are allowed. The maximum permitted velocity, V_{max}, for flares complying with this paragraph shall be determined by the following equation:

$\text{Log}_{10}(V_{max}) = (H_T + 28.8)/31.7$

Where:

V_{max} = Maximum permitted velocity, m/sec.

28.8 = Constant.

31.7 = Constant.

H_T = The net heating value as determined in paragraph (b)(6) of this section.

(8) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity V_{max}. The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation:

$V_{max} = 8.71 + 0.708(H_T)$

Where:

V_{max} = Maximum permitted velocity, m/sec.

8.71 = Constant.

0.708 = Constant.

H_T = The net heating value as determined in paragraph (b)(6)(ii) of this section.

(c) *Alternative work practice for monitoring equipment for leaks.* Paragraphs (c), (d), and (e) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, sppendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (c), (d), and (e) of this section continue to apply. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (c)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (c), (d), and (e) of this section.

(1) *Applicable subpart* means the subpart in 40 CFR parts 60, 61, 63, and 65 that requires monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(2) *Equipment* means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(3) *Imaging* means making visible emissions that may otherwise be invisible to the naked eye.

(4) *Optical gas imaging instrument* means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.

(5) *Repair* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.

(6) *Leak* means:

(i) Any emissions imaged by the optical gas instrument;

(ii) Indications of liquids dripping;

(iii) Indications by a sensor that a seal or barrier fluid system has failed; or

(iv) Screening results using a 40 CFR part 60, appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(d) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(1) An owner or operator of an affected source subject to 40 CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (e) of this section instead of using the 40 CFR part 60, appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.

(2) Any leak detected when following the leak survey procedure in paragraph (e)(3) of this section must be identified for repair as required in the applicable subpart.

(3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, Appendix A-7, Method 21 monitor at the leak definition required in the applicable subparts to which the equipment is subject.

(4) The schedule for repair is as required in the applicable subpart.

(5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.

(6) When this alternative work practice is used for detecting leaking equipment, the following are not applicable for the equipment being monitored:

(i) Skip period leak detection and repair;

(ii) Quality improvement plans; or

(iii) Complying with standards for allowable percentage of valves and pumps to leak.

(7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (d)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, Appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.

(e) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (e)(1) through (e)(5) of this section.

(1) *Instrument specifications.* The optical gas imaging instrument must comply with the requirements specified in paragraphs (e)(1)(i) and (e)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument

check described in paragraph (e)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) *Daily instrument check.* On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (e)(2)(i) of this section in accordance with the procedure specified in paragraphs (e)(2)(ii) through (e)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (e)(2)(v) of this section.

(i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (e)(2)(i)(A) and (e)(2)(i)(B) of this section.

(A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (e)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from the stream identified in paragraph (e)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

$$E_{dic} = (E_{sds}) \sum_{i=1}^{k} x_i$$

Where:

E_{dic} = Mass flow rate for the daily instrument check, grams per hour

x_i = Mass fraction of detectable chemical(s) i seen by the optical gas imaging instrument, within the distance to be used in paragraph (e)(2)(iv)(B) of this section, at or below the standard detection sensitivity level, E_{sds}.

E_{sds} = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

k = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate calculated in paragraph (e)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (e)(2)(ii) through (e)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under § 63.177 or § 63.178, whichever is applicable.

(3) *Leak survey procedure.* Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) *Recordkeeping.* Keep the records described in paragraphs (e)(4)(i) through (e)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.

(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (e)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (e)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (e)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (e)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) *Recordkeeping requirements in the applicable subpart.* A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subparts.

(5) *Reporting.* Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to *CCG-AWP@EPA.GOV.*

§ 63.12 State authority and delegations.

(a) The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from -

(1) Adopting and enforcing any standard, limitation, prohibition, or other regulation applicable to an affected source subject to the requirements of this part, provided that such standard, limitation, prohibition, or regulation is not less stringent than any requirement applicable to such source established under this part;

(2) Requiring the owner or operator of an affected source to obtain permits, licenses, or approvals prior to initiating construction, reconstruction, modification, or operation of such source; or

(3) Requiring emission reductions in excess of those specified in subpart D of this part as a condition for granting the extension of compliance authorized by section 112(i)(5) of the Act.

(b) (1) Section 112(l) of the Act directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards and other requirements pursuant to section 112 for stationary sources located in that State. Because of the unique nature of radioactive material, delegation of authority to implement and enforce standards that control radionuclides may require separate approval.

(2) Subpart E of this part establishes procedures consistent with section 112(l) for the approval of State rules or programs to implement and enforce applicable Federal rules promulgated under the authority of section 112. Subpart E also establishes procedures for the review and withdrawal of section 112 implementation and enforcement authorities granted through a section 112(l) approval.

(c) All information required to be submitted to the EPA under this part also shall be submitted to the appropriate state agency of any state to which authority has been delegated under section 112(l) of the Act, provided that each specific delegation may exempt sources from a certain federal or state reporting requirement. Any information required to be submitted electronically by this part via the EPA's CEDRI may, at the discretion of the delegated authority, satisfy the requirements of this paragraph. The Administrator may permit all or some of the information to be submitted to the appropriate state agency only, instead of to the EPA and the state agency with the exception of federal electronic reporting requirements under this part. Sources may not be exempted from federal electronic reporting requirements.

§ 63.13 Addresses of State air pollution control agencies and EPA Regional Offices.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted to the appropriate Regional Office of the U.S. Environmental Protection Agency indicated in the following list of EPA Regional offices. If a request, report, application, submittal, or other communication is required by this part to be submitted electronically via the EPA's CEDRI then such submission satisfies the requirements of this paragraph (a).

EPA Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont) Director, Enforcement and Compliance Assurance Division, U.S. EPA Region I, 5 Post Office Square - Suite 100 (04-2), Boston, MA 02109-3912, Attn: Air Compliance Clerk.

EPA Region II (New Jersey, New York, Puerto Rico, Virgin Islands), Director, Air and Waste Management Division, 26 Federal Plaza, New York, NY 10278.

EPA Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air Protection Division, 1650 Arch Street, Philadelphia, PA 19103.

EPA Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee). Director, Air, Pesticides and Toxics Management Division, Atlanta Federal Center, 61 Forsyth Street, Atlanta, GA 30303-3104.

EPA Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), Director, Air and Radiation Division, 77 West Jackson Blvd., Chicago, IL 60604-3507.

EPA Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas); Director; Enforcement and Compliance Assurance Division; U.S. Environmental Protection Agency, 1201 Elm Street, Suite 500, Mail Code 6ECD, Dallas, Texas 75270-2102.

EPA Region VII (Iowa, Kansas, Missouri, Nebraska), Director, Air and Waste Management Division, 11201 Renner Boulevard, Lenexa, Kansas 66219.

EPA Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming) Director, Air and Toxics Technical Enforcement Program, Office of Enforcement, Compliance and Environmental Justice, Mail Code 8ENF-AT, 1595 Wynkoop Street, Denver, CO 80202-1129.

EPA Region IX (Arizona, California, Hawaii, Nevada; the territories of American Samoa and Guam; the Commonwealth of the Northern Mariana Islands; the territories of Baker Island, Howland Island, Jarvis Island, Johnston Atoll, Kingman Reef, Midway Atoll, Palmyra Atoll, and Wake Islands; and certain U.S. Government activities in the freely associated states of the Republic of the Marshall Islands, the Federated States of Micronesia, and the Republic of Palau), Director, Air Division, 75 Hawthorne Street, San Francisco, CA 94105.

EPA Region X (Alaska, Idaho, Oregon, Washington), Director, Office of Air Quality, 1200 Sixth Avenue (OAQ-107), Seattle, WA 98101.

(b) All information required to be submitted to the Administrator under this part also shall be submitted to the appropriate State agency of any State to which authority has been delegated under section 112(l) of the Act. The owner or operator of an affected source may contact the appropriate EPA Regional Office for the mailing addresses for those States whose delegation requests have been approved.

(c) If any State requires a submittal that contains all the information required in an application, notification, request, report, statement, or other communication required in this part, an owner or

operator may send the appropriate Regional Office of the EPA a copy of that submittal to satisfy the requirements of this part for that communication.

§ 63.14 Incorporations by reference.

(a) The materials listed in this section are incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, a document must be published in the Federal Register and the material must be available to the public. All approved materials are available for inspection at the Air and Radiation Docket and Information Center (Air Docket) in the EPA Docket Center (EPA/DC) at Rm. 3334, EPA West Bldg., 1301 Constitution Ave. NW, Washington, DC. The EPA/DC Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number of the EPA/DC Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742. These approved materials are also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email fedreg.legal@nara.gov or go to www.archives.gov/federal-register/cfr/ibr-locations.html. In addition, these materials are available from the following sources:

(b) American Conference of Governmental Industrial Hygienists (ACGIH), Customer Service Department, 1330 Kemper Meadow Drive, Cincinnati, Ohio 45240, telephone number (513) 742–2020.

(1) Industrial Ventilation: A Manual of Recommended Practice, 22nd Edition, 1995, Chapter 3, “Local Exhaust Hoods” and Chapter 5, “Exhaust System Design Procedure.” IBR approved for §§ 63.843(b) and 63.844(b).

(2) Industrial Ventilation: A Manual of Recommended Practice, 23rd Edition, 1998, Chapter 3, “Local Exhaust Hoods” and Chapter 5, “Exhaust System Design Procedure.” IBR approved for §§ 63.1503, 63.1506(c), 63.1512(e), Table 2 to subpart RRR, Table 3 to subpart RRR, and appendix A to subpart RRR, and § 63.2984(e).

(3) Industrial Ventilation: A Manual of Recommended Practice for Design, 27th Edition, 2010. IBR approved for §§ 63.1503, 63.1506(c), 63.1512(e), Table 2 to subpart RRR, Table 3 to subpart RRR, and appendix A to subpart RRR, and § 63.2984(e).

(c) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporative Loss from External Floating-Roof Tanks, Third Edition, February 1989, IBR approved for §§ 63.111, 63.1402, 63.2406 and 63.7944.

Note 1 to paragraph (c)(1):

API Publication 2517 available through reseller HIS Markit at https://global.ihs.com/

(2) API Publication 2518, Evaporative Loss from Fixed-roof Tanks, Second Edition, October 1991, IBR approved for § 63.150(g).

(3) API Manual of Petroleum Measurement Specifications (MPMS) Chapter 19.2 (API MPMS 19.2), Evaporative Loss From Floating-Roof Tanks, First Edition, April 1997, IBR approved for §§ 63.1251 and 63.12005.

(d) American Public Health Association, 1015 18th Street NW, Washington, DC 20036; phone (844) 232–3707; email: standardmethods@subscritpionoffice.com; website: www.standardmethods.org.

(1) Standard Method 5210, Biochemical Oxygen Demand (BOD), revised December 10, 2019; IBR approved for § 63.457(c)

(2) [Reserved]

(e) American Society of Heating, Refrigerating, and Air-Conditioning Engineers at 1791 Tullie Circle, NE., Atlanta, GA 30329 orders@ashrae.org.

(1) American Society of Heating, Refrigerating, and Air-Conditioning Engineers Method 52.1, *Gravimetric and Dust-Spot Procedures for Testing Air-Cleaning Devices Used in General Ventilation for Removing Particulate Matter* June 4, 1992; IBR approved for § 63.11516(d).

(2) ANSI/ASHRAE Standard 52.2–2017, *Method of Testing General Ventilation Air-Cleaning Devices for Removal Efficiency by Particle Size,* copyright 2017; IBR approved for § 63.11173(e).

(f) American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, Telephone (800) 843–2763, http://www.asme.org*;* also available from HIS, Incorporated, 15 Inverness Way East, Englewood, CO 80112, Telephone (877) 413–5184, http://global.ihs.com*.*

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981, IBR approved for §§ 63.309(k), 63.457(k), 63.772(e) and (h), 63.865(b), 63.997(e), 63.1282(d) and (g), and 63.1625(b), table 5 to subpart EEEE, §§ 63.3166(a), 63.3360(e), 63.3545(a), 63.3555(a), 63.4166(a), 63.4362(a), 63.4766(a), 63.4965(a), and 63.5160(d), table 4 to subpart UUUU, table 3 to subpart YYYY, §§ 63.7822(b), 63.7824(e), 63.7825(b), 63.8000(d), 63.9307(c), 63.9323(a), 63.9621(b) and (c), 63.11148(e), 63.11155(e), 63.11162(f), 63.11163(g), 63.11410(j), 63.11551(a), 63.11646(a), and 63.11945, and table 4 to subpart AAAAA, table 5 to subpart DDDDD, table 4 to subpart JJJJJ, table 4 to subpart KKKKK, table 4 to subpart SSSSS, tables 4 and 5 of subpart UUUUU, table 1 to subpart ZZZZZ, and table 4 to subpart JJJJJJ.

(2) [Reserved]

(g) The Association of Florida Phosphate Chemists, P.O. Box 1645, Bartow, Florida 33830.

(1) Book of Methods Used and Adopted By The Association of Florida Phosphate Chemists, Seventh Edition 1991:

(i) Section IX, Methods of Analysis for Phosphate Rock, No. 1 Preparation of Sample, IBR approved for § 63.606(f), § 63.626(f).

(ii) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P2O5 or Ca3(PO4)2, Method A—Volumetric Method, IBR approved for § 63.606(f), § 63.626(f).

(iii) Section IX, Methods of Analysis for Phosphate Rock, No. 3 Phosphorus-P2O5 or Ca3(PO4)2, Method B—Gravimetric Quimociac Method, IBR approved for § 63.606(f), § 63.626(f).

(iv) Section IX, Methods of Analysis For Phosphate Rock, No. 3 Phosphorus-P2O5 or Ca3(PO4)2, Method C—Spectrophotometric Method, IBR approved for § 63.606(f), § 63.626(f).

(v) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P2O5, Method A—Volumetric Method, IBR approved for § 63.606(f), § 63.626(f), and (g).

(vi) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P2O5, Method B—Gravimetric Quimociac Method, IBR approved for § 63.606(f), § 63.626(f), and (g).

(vii) Section XI, Methods of Analysis for Phosphoric Acid, Superphosphate, Triple Superphosphate, and Ammonium Phosphates, No. 3 Total Phosphorus-P2O5, Method C—Spectrophotometric Method, IBR approved for § 63.606(f), § 63.626(f), and (g).

(2) [Reserved]

(h) Association of Official Analytical Chemists (AOAC) International, Customer Services, Suite 400, 2200 Wilson Boulevard, Arlington, Virginia 22201–3301, Telephone (703) 522–3032, Fax (703) 522–5468.

(1) AOAC Official Method 929.01 Sampling of Solid Fertilizers, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(2) AOAC Official Method 929.02 Preparation of Fertilizer Sample, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(3) AOAC Official Method 957.02 Phosphorus (Total) in Fertilizers, Preparation of Sample Solution, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(4) AOAC Official Method 958.01 Phosphorus (Total) in Fertilizers, Spectrophotometric Molybdovanadophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(5) AOAC Official Method 962.02 Phosphorus (Total) in Fertilizers, Gravimetric Quinolinium Molybdophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(6) AOAC Official Method 969.02 Phosphorus (Total) in Fertilizers, Alkalimetric Quinolinium Molybdophosphate Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(7) AOAC Official Method 978.01 Phosphorus (Total) in Fertilizers, Automated Method, Sixteenth edition, 1995, IBR approved for § 63.626(g).

(i) ASTM International, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, http://www.astm.org; also available from ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, http://www.proquest.com.

(1) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

(2) ASTM D240–09 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD.

(3) ASTM Method D388–05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for §§ 63.7575, 63.10042, and 63.11237.

(4) ASTM Method D396–10, Standard Specification for Fuel Oils, including Appendix X1, approved October 1, 2010, IBR approved for § 63.10042.

(5) ASTM D396–10, Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for §§ 63.7575 and 63.11237.

(6) ASTM D523–89, Standard Test Method for Specular Gloss, IBR approved for § 63.782.

(7) ASTM D975–11b, Standard Specification for Diesel Fuel Oils, approved December 1, 2011, IBR approved for § 63.7575.

(8) ASTM D1193–77, Standard Specification for Reagent Water, IBR approved for appendix A to part 63: Method 306, Sections 7.1.1 and 7.4.2.

(9) ASTM D1193–91, Standard Specification for Reagent Water, IBR approved for appendix A to part 63: Method 306, Sections 7.1.1 and 7.4.2.

(10) ASTM D1331–89, Standard Test Methods for Surface and Interfacial Tension of Solutions of Surface Active Agents, IBR approved for appendix A to part 63: Method 306B, Sections 6.2, 11.1, and 12.2.2.

(11) ASTM D1475–90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for appendix A to subpart II.

(12) ASTM D1475–13, Standard Test Method for Density of Liquid Coatings, Inks, and Related Products, approved November 1, 2013, IBR approved for §§ 63.3151(b), 63.3941(b) and (c), 63.3951(c), 63.4141(b) and (c), 63.4551(c), 63.4741(b) and (c), 63.4751(c), and 63.4941(b) and (c).

(13) ASTM Method D1835–05, Standard Specification for Liquefied Petroleum (LP) Gases, approved April 1, 2005, IBR approved for §§ 63.7575 and 63.11237.

(14) ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, Approved January 1, 2010, IBR approved for §§ 63.670(j), 63.772(h), and 63.1282(g).

(15) ASTM D1945–14, Standard Test Method for Analysis of Natural Gas by Gas Chromatography, Approved November 1, 2014, IBR approved for § 63.670(j).

(16) ASTM D1946–77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for § 63.11(b).

(17) ASTM D1946–90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, 1994, IBR approved for §§ 63.11(b), 63.987(b), and 63.1412.

(18) ASTM D1963–85 (Reapproved 1996), Standard Test Method for Specific Gravity of Drying Oils, Varnishes, Resins, and Related Materials at 25/25 °C, approved November 29, 1985, IBR approved for § 63.3360(c).

(19) ASTM D2013/D2013M–09, Standard Practice for Preparing Coal Samples for Analysis, (Approved November 1, 2009), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(20) ASTM D2099–00, Standard Test Method for Dynamic Water Resistance of Shoe Upper Leather by the Maeser Water Penetration Tester, IBR approved for § 63.5350.

(21) ASTM D2111–10 (Reapproved 2015), Standard Test Methods for Specific Gravity and Density of Halogenated Organic Solvents and Their Admixtures, approved June 1, 2015, IBR approved for §§ 63.3360(c), 63.3951(c), 63.4141(b) and (c), 63.4551(c), and 63.4741(a).

(22) ASTM D2216–05, Standard Test Methods for Laboratory Determination of Water (Moisture) Content of Soil and Rock by Mass, IBR approved for the definition of “Free organic liquids” in § 63.10692.

(23) ASTM D2234/D2234M–10, Standard Practice for Collection of a Gross Sample of Coal, approved January 1, 2010, IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(24) ASTM D2369–93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A to subpart II.

(25) ASTM D2369–95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A to subpart II.

(26) ASTM D2369–10 (Reapproved 2015)e1, Standard Test Method for Volatile Content of Coatings, approved June 1, 2015, IBR approved for §§ 63.3151(a), 63.3360(c), 63.3961(j), 63.4141(a) and (b), 63.4161(h), 63.4321(e), 63.4341(e), 63.4351(d), 63.4541(a), and 63.4561(j), appendix A to subpart PPPP, and §§ 63.4741(a), 63.4941(a) and (b), 63.4961(j), and 63.8055(b).

(27) ASTM D2382–76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for § 63.11(b).

(28) ASTM D2382–88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for § 63.11(b).

(29) ASTM D2697–86 (Reapproved 1998), Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings, IBR approved for §§ 63.3521(b), and 63.5160(c).

(30) ASTM D2697–03 (Reapproved 2014), Standard Test Method for Volume Nonvolatile Matter in Clear or Pigmented Coatings, approved July 1, 2014, IBR approved for §§ 63.3161(f), 63.3360(c), 63.3941(b), 63.4141(b), 63.4741(a) and (b), 63.4941(b), and 63.8055(b).

(31) ASTM D2879–83, Standard Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, Approved November 28, 1983, IBR approved for §§ 63.111, 63.1402, 63.2406, 63.7944, and 63.12005.

(32) ASTM D2879–96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, (Approved 1996), IBR approved for §§ 63.111, and 63.12005.

(33) ASTM D2908–74, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, Approved June 27, 1974, IBR approved for § 63.1329(c).

(34) ASTM D2908–91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, Approved December 15, 1991, IBR approved for § 63.1329(c).

(35) ASTM D2908–91(Reapproved 2001), Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, Approved December 15, 1991, IBR approved for § 63.1329(c).

(36) ASTM D2908–91(Reapproved 2005), Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, Approved December 1, 2005, IBR approved for § 63.1329(c).

(37) ASTM D2908–91(Reapproved 2011), Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, Approved May 1, 2011, IBR approved for § 63.1329(c).

(38) ASTM D2986–95A, "Standard Practice for Evaluation of Air Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test," approved September 10, 1995, IBR approved for section 7.1.1 of Method 315 in appendix A to this part.

(39) ASTM D3173–03 (Reapproved 2008), Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, (Approved February 1, 2008), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(40) ASTM D3257–93, Standard Test Methods for Aromatics in Mineral Spirits by Gas Chromatography, IBR approved for § 63.786(b).

(41) ASTM D3370–76, Standard Practices for Sampling Water, Approved August 27, 1976, IBR approved for § 63.1329(c).

(42) ASTM D3370–95a, Standard Practices for Sampling Water from Closed Conduits, Approved September 10, 1995, IBR approved for § 63.1329(c).

(43) ASTM D3370–07, Standard Practices for Sampling Water from Closed Conduits, Approved December 1, 2007, IBR approved for § 63.1329(c).

(44) ASTM D3370–08, Standard Practices for Sampling Water from Closed Conduits, Approved October 1, 2008, IBR approved for § 63.1329(c).

(45) ASTM D3370–10, Standard Practices for Sampling Water from Closed Conduits, Approved December 1, 2010, IBR approved for § 63.1329(c).

(46) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§ 63.772(h) and 63.1282(g).

(47) ASTM D3695–88, Standard Test Method for Volatile Alcohols in Water by Direct Aqueous-Injection Gas Chromatography, IBR approved for § 63.365(e).

(48) ASTM D3792–91, Standard Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A to subpart II.

(49) ASTM D3912–80, Standard Test Method for Chemical Resistance of Coatings Used in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(50) ASTM D3960–98, Standard Practice for Determining Volatile Organic Compound (VOC) Content of Paints and Related Coatings, approved November 10, 1998, IBR approved for §§ 63.3360(c) and 63.8055(b).

(51) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, (Approved June 1, 2011), IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

(52) ASTM D4017–81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A to subpart II.

(53) ASTM D4017–90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A to subpart II.

(54) ASTM D4017–96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A to subpart II.

(55) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, (Approved June 1, 2011), IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

(56) ASTM D4082–89, Standard Test Method for Effects of Gamma Radiation on Coatings for Use in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(57) ASTM D4084–07, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), (Approved June 1, 2007), IBR approved for table 6 to subpart DDDDD.

(58) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, (Approved May 1, 2010), IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

(59) ASTM D4208–02 (Reapproved 2007), Standard Test Method for Total Chlorine in Coal by the Oxygen Bomb Combustion/Ion Selective Electrode Method, approved May 1, 2007, IBR approved for table 6 to subpart DDDDD.

(60) ASTM D4239–14e1, "Standard Test Method for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion," approved March 1, 2014, IBR approved for § 63.849(f).

(61) ASTM D4256–89, Standard Test Method for Determination of the Decontaminability of Coatings Used in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(62) ASTM D4256–89 (Reapproved 94), Standard Test Method for Determination of the Decontaminability of Coatings Used in Light-Water Nuclear Power Plants, IBR approved for § 63.782.

(63) ASTM D4282–15, Standard Test Method for Determination of Free Cyanide in Water and Wastewater by Microdiffusion, Approved July 15, 2015, IBR approved for § 63.1103(g).

(64) ASTM D4606–03 (Reapproved 2007), Standard Test Method for Determination of Arsenic and Selenium in Coal by the Hydride Generation/Atomic Absorption Method, (Approved October 1, 2007), IBR approved for table 6 to subpart DDDDD.

(65) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for § 63.11(b).

(66) ASTM D4840–99 (Reapproved 2018)e, Standard Guide for Sampling Chain-of-Custody Procedures, approved August 15, 2018, IBR approved for appendix A to part 63.

(67) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§ 63.772(h) and 63.1282(g).

(68) ASTM D5066–91 (Reapproved 2017), Standard Test Method for Determination of the Transfer Efficiency Under Production Conditions for Spray Application of Automotive Paints-Weight Basis, approved June 1, 2017, IBR approved for § 63.3161(g).

(69) ASTM D5087–02, Standard Test Method for Determining Amount of Volatile Organic Compound (VOC) Released from Solventborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), IBR approved for § 63.3165(e) and appendix A to subpart IIII.

(70) ASTM D5192–09, Standard Practice for Collection of Coal Samples from Core, (Approved June 1, 2009), IBR approved for table 6 to subpart DDDDD.

(71) ASTM D5198–09, Standard Practice for Nitric Acid Digestion of Solid Waste, (Approved February 1, 2009), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(72) ASTM D5228–92, Standard Test Method for Determination of Butane Working Capacity of Activated Carbon, (Reapproved 2005), IBR approved for § 63.11092(b).

(73) ASTM D5291–02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, IBR approved for appendix A to subpart MMMM.

(74) ASTM D5790–95 (Reapproved 2012), Standard Test Method for Measurement of Purgeable Organic Compounds in Water by Capillary Column Gas Chromatography/Mass Spectrometry, Approved June 15, 2012, IBR approved for § 63.2485(h) and Table 4 to subpart UUUU.

(75) ASTM D5864–11, Standard Test Method for Determining Aerobic Aquatic Biodegradation of Lubricants or Their Components, (Approved March 1, 2011), IBR approved for table 6 to subpart DDDDD.

(76) ASTM D5865–10a, Standard Test Method for Gross Calorific Value of Coal and Coke, (Approved May 1, 2010), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(77) ASTM D5954–98 (Reapproved 2006), Test Method for Mercury Sampling and Measurement in Natural Gas by Atomic Absorption Spectroscopy, (Approved December 1, 2006), IBR approved for table 6 to subpart DDDDD.

(78) ASTM D5965–02 (Reapproved 2013), Standard Test Methods for Specific Gravity of Coating Powders, approved June 1, 2013, IBR approved for §§ 63.3151(b) and 63.3951(c).

(79) ASTM D6053–00, Standard Test Method for Determination of Volatile Organic Compound (VOC) Content of Electrical Insulating Varnishes, IBR approved for appendix A to subpart MMMM.

(80) ASTM D6093–97 (Reapproved 2003), Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer, IBR approved for §§ 63.3521 and 63.5160(c).

(81) ASTM D6093–97 (Reapproved 2016), Standard Test Method for Percent Volume Nonvolatile Matter in Clear or Pigmented Coatings Using a Helium Gas Pycnometer, approved December 1, 2016, IBR approved for §§ 63.3161(f), 63.3360(c), 63.3941(b), 63.4141(b), 63.4741(a) and (b), and 63.4941(b).

(82) ASTM D6196–03 (Reapproved 2009), Standard Practice for Selection of Sorbents, Sampling, and Thermal Desorption Analysis Procedures for Volatile Organic Compounds in Air, Approved March 1, 2009, IBR approved for appendix A to this part: Method 325A and Method 325B.

(83) ASTM D6266–00a (Reapproved 2017), Standard Test Method for Determining the Amount of Volatile Organic Compound (VOC) Released from Waterborne Automotive Coatings and Available for Removal in a VOC Control Device (Abatement), approved July 1, 2017, IBR approved for § 63.3165(e).

(84) ASTM D6323–98 (Reapproved 2003), Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities, (Approved August 10, 2003), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(85) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, Approved October 1, 2003, IBR approved for §§ 63.457(b), 63.997(e), and 63.1349, table 4 to subpart DDDD, table 5 to subpart EEEE, table 4 to subpart UUUU, table 4 subpart ZZZZ, and table 8 to subpart HHHHHHH.

(86) ASTM D6348–03 (Reapproved 2010), Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, including Annexes A1 through A8, Approved October 1, 2010, IBR approved for §§ 63.1571(a), 63.4751(i), 63.4752(e), 63.4766(b), 63.7142(a) and (b), tables 4 and 5 to subpart JJJJJ, tables 4 and 6 to subpart KKKKK, tables 1, 2, and 5 to subpart UUUUU and appendix B to subpart UUUUU.

(87) ASTM D6348–12e1, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, Approved February 1, 2012, IBR approved for §§ 63.997(e), 63.1571(a), and 63.2354(b), table 5 to subpart EEEE, table 4 to subpart UUUU, §§ 63.7142(a) and (b) and 63.8000(d), and table 4 to subpart SSSSS.

(88) ASTM D6350–98 (Reapproved 2003), Standard Test Method for Mercury Sampling and Analysis in Natural Gas by Atomic Fluorescence Spectroscopy, (Approved May 10, 2003), IBR approved for table 6 to subpart DDDDD.

(89) ASTM D6357–11, Test Methods for Determination of Trace Elements in Coal, Coke, and Combustion Residues from Coal Utilization Processes by Inductively Coupled Plasma Atomic Emission Spectrometry, (Approved April 1, 2011), IBR approved for table 6 to subpart DDDDD.

(90) ASTM D6376–10, "Standard Test Method for Determination of Trace Metals in Petroleum Coke by Wavelength Dispersive X-Ray Fluorescence Spectroscopy," Approved July 1, 2010, IBR approved for § 63.849(f).

(91) [Reserved]

(92) ASTM D6420–99, Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, IBR approved for §§ 63.5799 and 63.5850.

(93) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (Approved October 1, 2004), IBR approved for §§ 63.457(b), 63.772(a), 63.772(e), 63.1282(a) and (d), and table 8 to subpart HHHHHHH.

(94) ASTM D6420–99 (Reapproved 2010), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, Approved October 1, 2010, IBR approved for §§ 63.670(j), Table 4 to subpart UUUU, 63.7142(b), and appendix A to this part: Method 325B.

(95) ASTM D6420–18, Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, approved November 1, 2018, IBR approved for §§ 63.987(b), 63.997(e), and 63.2354(b), table 5 to subpart EEEE, and §§ 63.2450(j) and 63.8000(d).

(96) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 63.9307(c).

(97) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, (Approved October 1, 2005), IBR approved for table 4 to subpart ZZZZ, table 5 to subpart DDDDDD, table 4 to subpart JJJJJJ, and §§ 63.772(e) and (h)) and 63.1282(d) and (g).

(98) ASTM D6522–11 Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, Approved December 1, 2011, IBR approved for § 63.1961(a) and table 3 to subpart YYYY.

(99) ASTM D6721–01 (Reapproved 2006), Standard Test Method for Determination of Chlorine in Coal by Oxidative Hydrolysis Microcoulometry, (Approved April 1, 2006), IBR approved for table 6 to subpart DDDDD.

(100) ASTM D6722–01 (Reapproved 2006), Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by the Direct Combustion Analysis, (Approved April 1, 2006), IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ.

(101) ASTM D6735–01 (Reapproved 2009), Standard Test Method for Measurement of Gaseous Chlorides and Fluorides from Mineral Calcining Exhaust Sources—Impinger Method, IBR approved for § 63.7142(b), tables 4 and 5 to subpart JJJJJ, and tables 4 and 6 to subpart KKKKK.

(102) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, (Approved July 15, 2011), IBR approved for §§ 63.7575 and 63.11237.

(103) ASTM D6784–02 (Reapproved 2008), Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), Approved April 1, 2008; IBR approved for §§ 63.2465(d); 63.11646(a); 63.11647(a) and (d); tables 1, 2, 5, 11, 12t, and 13 to subpart DDDDD; tables 4 and 5 to subpart JJJJJ; tables 4 and 6 to subpart KKKKK; table 4 to subpart JJJJJJ.

(104) ASTM D6784–16, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), Approved March 1, 2016; IBR approved for table 5 to subpart UUUUU; appendix A to subpart UUUUU.

(105) ASTM D6883–04, Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, (Approved June 1, 2004), IBR approved for table 6 to subpart DDDDD.

(106) ASTM D6886–18, Standard Test Method for Determination of the Weight Percent Individual Volatile Organic Compounds in Waterborne Air-Dry Coatings by Gas Chromatography, approved October 1, 2018, IBR approved for § 63.2354(c).

(107) ASTM D7237–18, Standard Test Method for Free Cyanide and Aquatic Free Cyanide with Flow Injection Analysis (FIA) Utilizing Gas Diffusion Separation and Amperometric Detection, Approved December 1, 2018, IBR approved for § 63.1103(g).

(108) ASTM D7430–11ae1, Standard Practice for Mechanical Sampling of Coal, (Approved October 1, 2011), IBR approved for table 6 to subpart DDDDD.

(109) ASTM D7520–16, Standard Test Method for Determining the Opacity of a Plume in the Outdoor Ambient Atmosphere, approved April 1, 2016; IBR approved for §§ 63.1625(b); table 3 to subpart LLLLL; 63.7823(c) through (e), 63.7833(g); 63.11423(c).

(110) [Reserved]

(111) ASTM E145–94 (Reapproved 2001), Standard Specification for Gravity-Convection and Forced-Ventilation Ovens, IBR approved for appendix A to subpart PPPP.

(112) ASTM E180–93, Standard Practice for Determining the Precision of ASTM Methods for Analysis and Testing of Industrial Chemicals, IBR approved for § 63.786(b).

(113) ASTM E260–91, General Practice for Packed Column Gas Chromatography, IBR approved for §§ 63.750(b) and 63.786(b).

(114) ASTM E260–96, General Practice for Packed Column Gas Chromatography, IBR approved for §§ 63.750(b) and 63.786(b).

(115) ASTM E515–95 (Reapproved 2000), Standard Test Method for Leaks Using Bubble Emission Techniques, IBR approved for § 63.425(i).

(116) ASTM E711–87 (Reapproved 2004), Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, (Approved August 28, 1987), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(117) ASTM E776–87 (Reapproved 2009), Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel, (Approved July 1, 2009), IBR approved for table 6 to subpart DDDDD.

(118) ASTM E871–82 (Reapproved 2006), Standard Test Method for Moisture Analysis of Particulate Wood Fuels, (Approved November 1, 2006), IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(119) ASTM UOP539–12, Refinery Gas Analysis by GC, Copyright 2012 (to UOP), IBR approved for § 63.670(j).

(j) Bay Area Air Quality Management District (BAAQMD), 939 Ellis Street, San Francisco, California 94109, http://www.arb.ca.gov/DRDB/BA/CURHTML/ST/st30.pdf.

(1) "BAAQMD Source Test Procedure ST–30—Static Pressure Integrity Test, Underground Storage Tanks," adopted November 30, 1983, and amended December 21, 1994, IBR approved for § 63.11120(a).

(2) [Reserved]

(k) British Standards Institute, 389 Chiswick High Road, London W4 4AL, United Kingdom.

(1) BS EN 1593:1999, Non-destructive Testing: Leak Testing—Bubble Emission Techniques, IBR approved for § 63.425(i).

(2) BS EN 14662–4:2005, Ambient air quality standard method for the measurement of benzene concentrations—Part 4: Diffusive sampling followed by thermal desorption and gas chromatography, Published June 27, 2005, IBR approved for appendix A to this part: Method 325A and Method 325B.

(l) California Air Resources Board (CARB), 1001 I Street, P.O. Box 2815, Sacramento, CA 95812–2815, Telephone (916) 327–0900, http://www.arb.ca.gov/.

(1) Method 310, "Determination of Volatile Organic Compounds (VOC) in Consumer Products and Reactive Organic Compounds (ROC) in Aerosol Coating Products," amended May 25, 2018, IBR approved for § 63.8055(b).

(2) Method 428, "Determination Of Polychlorinated Dibenzo-P-Dioxin (PCDD), Polychlorinated Dibenzofuran (PCDF), and Polychlorinated Biphenyle Emissions from Stationary Sources," amended September 12, 1990, IBR approved for § 63.849(a)(13) and (14).

(3) Method 429, Determination of Polycyclic Aromatic Hydrocarbon (PAH) Emissions from Stationary Sources, Adopted September 12, 1989, Amended July 28, 1997, IBR approved for § 63.1625(b).

(4) California Air Resources Board Vapor Recovery Test Procedure TP–201.1—"Volumetric Efficiency for Phase I Vapor Recovery Systems," adopted April 12, 1996, and amended February 1, 2001 and October 8, 2003, IBR approved for § 63.11120(b).

(5) California Air Resources Board Vapor Recovery Test Procedure TP–201.1E—"Leak Rate and Cracking Pressure of Pressure/Vacuum Vent Valves," adopted October 8, 2003, IBR approved for § 63.11120(a).

(6) California Air Resources Board Vapor Recovery Test Procedure TP–201.3—"Determination of 2-Inch WC Static Pressure Performance of Vapor Recovery Systems of Dispensing Facilities," adopted April 12, 1996 and amended March 17, 1999, IBR approved for § 63.11120(a).

(m) Composite Panel Association, 19465 Deerfield Avenue, Suite 306, Leesburg, VA 20176, Telephone (703)724–1128, and www.compositepanel.org.

(1) ANSI A135.4–2012, Basic Hardboard, approved June 8, 2012, IBR approved for § 63.4781.

(2) [Reserved]

(n) Environmental Protection Agency. Air and Radiation Docket and Information Center, 1200 Pennsylvania Avenue NW., Washington, DC 20460, telephone number (202) 566–1745.

(1) *California Regulatory Requirements Applicable to the Air Toxics Program,* November 16, 2010, IBR approved for § 63.99(a).

(2) New Jersey's *Toxic Catastrophe Prevention Act Program,* (July 20, 1998), IBR approved for § 63.99(a).

(3) Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management, Accidental Release Prevention Regulation, sections 1 through 5 and sections 7 through 14, effective January 11, 1999, IBR approved for § 63.99(a).

(4) State of Delaware Regulations Governing the Control of Air Pollution (October 2000), IBR approved for § 63.99(a).

(5) Massachusetts Department of Environmental Protection regulations at 310 CMR 7.26(10)–(16), Air Pollution Control, effective as of September 5, 2008, corrected March 6, 2009, and 310 CMR 70.00, Environmental Results Program Certification, effective as of December 28, 2007. IBR approved for § 63.99(a).

(6)

(i) New Hampshire Regulations at Env-Sw 2100, Management and Control of Asbestos Disposal Sites Not Operated after July 9, 1981, effective February 16, 2010 (including a letter from Thomas S. Burack, Commissioner, Department of Environmental Services, State of New Hampshire, to Carol J. Holahan, Director, Office of Legislative Services, dated February 12, 2010, certifying that the enclosed rule, Env-Sw 2100, is the official version of this rule), IBR approved for § 63.99(a).

(ii) New Hampshire Code of Administrative Rules: Chapter Env-A 1800, Asbestos Management and Control, effective as of May 5, 2017 (certified with June 23, 2017 letter from Clark B. Freise, Assistant Commissioner, Department of Environmental Services, State of New Hampshire), as follows: Revision Notes #1 and #2; Part Env-A 1801–1807, excluding Env-A 1801.02(e), Env-A 1801.07, Env-A 1802.02, Env-A 1802.04, Env-A 1802.07–1802.09, Env-A 1802.13, Env-A 1802.15–1802.17, Env-A 1802.25, Env-A 1802.31, Env-A 1802.37, Env-A 1802.40, Env-A 1802.44, and Env-A 1803.05–1803.09; and Appendices B, C, and D; IBR approved for § 63.99(a).

(7) Maine Department of Environmental Protection regulations at Chapter 125, Perchloroethylene Dry Cleaner Regulation, effective as of June 2, 1991, last amended on June 24, 2009. IBR approved for § 63.99(a).

(8) California South Coast Air Quality Management District's "Spray Equipment Transfer Efficiency Test Procedure for Equipment User, May 24, 1989," IBR approved for §§ 63.11173(e) and 63.11516(d).

(9) California South Coast Air Quality Management District's "Guidelines for Demonstrating Equivalency with District Approved Transfer Efficient Spray Guns, September 26, 2002," Revision 0, IBR approved for §§ 63.11173(e) and 63.11516(d).

(10) Rhode Island Department of Environmental Management regulations at Air Pollution Control Regulation No. 36, Control of Emissions from Organic Solvent Cleaning, effective April 8, 1996, last amended October 9, 2008, IBR approved for § 63.99(a).

(11) Rhode Island Air Pollution Control, General Definitions Regulation, effective July 19, 2007, last amended October 9, 2008. IBR approved for § 63.99(a).

(12) Alaska Statute 42.45.045. Renewable energy grant fund and recommendation program, available at http://www.legis.state.ak.us/basis/folio.asp, IBR approved for § 63.6675.

(13) Vermont Air Pollution Control Regulations, Chapter 5, Air Pollution Control, section 5–253.11, Perchloroethylene Dry Cleaning, effective as of December 15, 2016. Incorporation by reference approved for § 63.99(a).

(o) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., Washington, DC 20460, (202) 272–0167, http://www.epa.gov.

(1) EPA–453/R–08–002, Protocol for Determining the Daily Volatile Organic Compound Emission Rate of Automobile and Light-Duty Truck Primer-Surfacer and Topcoat, published September 2008, IBR approved for §§ 63.3130(c), 63.3161(d) and (g), 63.3165(e), and appendix A to subpart IIII.

(2) EPA–453/R–01–005, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards, Final Report, January 2001, IBR approved for § 63.7491(g).

(3) [Reserved]

(4) EPA–454/R–98–015, Office of Air Quality Planning and Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, September 1997, https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=2000D5T6.PDF; IBR approved for §§ 63.548(e); 63.864(e); 63.7525(j); 63.8450(e); 63.8600(e); 63.9632(a); 63.9804(f); 63.11224(f); 63.11423(e).

(5) EPA–454/R–99–005, Office of Air Quality Planning and Standards (OAQPS), Meteorological Monitoring Guidance for Regulatory Modeling Applications, February 2000, IBR approved for appendix A to this part: Method 325A.

(6) EPA/600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards, May 2012, IBR approved for § 63.2163(b).

(7) EPA–625/3–89–016, Interim Procedures for Estimating Risks Associated with Exposures to Mixtures of Chlorinated Dibenzo-p-Dioxins and –Dibenzofurans (CDDs and CDFs) and 1989 Update, March 1989. IBR approved for § 63.1513(d).

(8) SW–846–0011, Sampling for Selected Aldehyde and Ketone Emissions from Stationary Sources, Revision 0, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 4 to subpart DDDD.

(9) SW–846–3020A, Acid Digestion of Aqueous Samples And Extracts For Total Metals For Analysis By GFAA Spectroscopy, Revision 1, July 1992, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(10) SW–846–3050B, Acid Digestion of Sediments, Sludges, and Soils, Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(11) SW–846–5030B, Purge-And-Trap For Aqueous Samples, Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for § 63.2492(b) and (c).

(12) SW–846–5031, Volatile, Nonpurgeable, Water-Soluble Compounds by Azeotropic Distillation, Revision 0, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for § 63.2492(b) and (c).

(13) SW–846–7470A, Mercury In Liquid Waste (Manual Cold-Vapor Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(14) SW–846–7471B, Mercury In Solid Or Semisolid Waste (Manual Cold-Vapor Technique), Revision 2, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD and table 5 to subpart JJJJJJ.

(15) SW–846–8015C, Nonhalogenated Organics by Gas Chromatography, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.11960, 63.11980, and table 10 to subpart HHHHHHH.

(16) SW–846–8260B, Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.1107(a), 63.11960, 63.11980, and table 10 to subpart HHHHHHH.

(17) SW–846–8260D, Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry, Revision 4, June 2018, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for § 63.2492(b) and (c).

(18) SW–846–8270D, Semivolatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS), Revision 4, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.1107(a), 63.11960, 63.11980, and table 10 to subpart HHHHHHH.

(19) SW–846–8315A, Determination of Carbonyl Compounds by High Performance Liquid Chromatography (HPLC), Revision 1, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for §§ 63.11960 and 63.11980, and table 10 to subpart HHHHHHH.

(20) SW–846–5050, Bomb Preparation Method for Solid Waste, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition IBR approved for table 6 to subpart DDDDD.

(21) SW–846–6010C, Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(22) SW–846–6020A, Inductively Coupled Plasma-Mass Spectrometry, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(23) SW–846–7060A, Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(24) SW–846–7740, Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(25) SW–846–9056, Determination of Inorganic Anions by Ion Chromatography, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(26) SW–846–9076, Test Method for Total Chlorine in New and Used Petroleum Products by Oxidative Combustion and Microcoulometry, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(27) SW–846–9250, Chloride (Colorimetric, Automated Ferricyanide AAI), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(28) Method 200.8, Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma—Mass Spectrometry, Revision 5.4, 1994, IBR approved for table 6 to subpart DDDDD.

(29) Method 1631 Revision E, Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Absorption Fluorescence Spectrometry, Revision E, EPA–821–R–02–019, August 2002, IBR approved for table 6 to subpart DDDDD.

(p) International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, + 41 22 749 01 11, http://www.iso.org/iso/home.htm.

(1) ISO 6978–1:2003(E), Natural Gas—Determination of Mercury—Part 1: Sampling of Mercury by Chemisorption on Iodine, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD.

(2) ISO 6978–2:2003(E), Natural gas—Determination of Mercury—Part 2: Sampling of Mercury by Amalgamation on Gold/Platinum Alloy, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD.

(3) ISO 16017–2:2003(E): Indoor, ambient and workplace air—sampling and analysis of volatile organic compounds by sorbent tube/thermal desorption/capillary gas chromatography—Part 2: Diffusive sampling, May 15, 2003, IBR approved for appendix A to this part: Method 325A and Method 325B.

(q) National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI), P.O. Box 133318, Research Triangle Park, NC 27709–3318 or at http://www.ncasi.org.

(1) NCASI Method DI/MEOH–94.03, Methanol in Process Liquids and Wastewaters by GC/FID, Issued May 2000, IBR approved for §§ 63.457 and 63.459.

(2) NCASI Method CI/WP–98.01, Chilled Impinger Method For Use At Wood Products Mills to Measure Formaldehyde, Methanol, and Phenol, 1998, Methods Manual, IBR approved for table 4 to subpart DDDD.

(3) NCASI Method DI/HAPS–99.01, Selected HAPs In Condensates by GC/FID, Issued February 2000, IBR approved for § 63.459(b).

(4) NCASI Method IM/CAN/WP–99.02, Impinger/Canister Source Sampling Method for Selected HAPs and Other Compounds at Wood Products Facilities, January 2004, Methods Manual, IBR approved for table 4 to subpart DDDD.

(5) NCASI Method ISS/FP A105.01, Impinger Source Sampling Method for Selected Aldehydes, Ketones, and Polar Compounds, December 2005, Methods Manual, IBR approved for table 4 to subpart DDDD and §§ 63.4751(i) and 63.4752(e).

(r) National Technical Information Service (NTIS), 5285 Port Royal Road, Springfield, VA 22161, (703) 605–6000 or (800) 553–6847; or for purchase from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, (202) 512–1800.

(1) Handbook 44, Specificiations, Tolerances, and Other Technical Requirements for Weighing and Measuring Devices 1998, IBR approved for § 63.1303(e).

(2) "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," EPA Publication SW–846, Third Edition. (A suffix of "A" in the method number indicates revision one (the method has been revised once). A suffix of "B" in the method number indicates revision two (the method has been revised twice).

(i) Method 0023A, "Sampling Method for Polychlorinated Dibenzo-p-Dioxins and Polychlorinated Dibenzofuran Emissions from Stationary Sources," Revision 2, dated August 2018, IBR approved for § 63.1208(b).

(ii) Method 9071B, "n-Hexane Extractable Material (HEM) for Sludge, Sediment, and Solid Samples," dated April 1998, IBR approved for § 63.7824(e).

(iii) Method 9095A, "Paint Filter Liquids Test," dated December 1996, IBR approved for §§ 63.7700(b) and 63.7765.

(iv) Method 9095B, "Paint Filter Liquids Test," (revision 2), dated November 2004, IBR approved for the definition of "Free organic liquids" in §§ 63.10692, 63.10885(a), and the definition of "Free liquids" in § 63.10906.

(v) SW–846 74741B, Revision 2, "Mercury in Solid or Semisolid Waste (Manual Cold-Vapor Technique)," February 2007, IBR approved for § 63.11647(f).

(3) National Institute of Occupational Safety and Health (NIOSH) test method compendium, "NIOSH Manual of Analytical Methods," NIOSH publication no. 94–113, Fourth Edition, August 15, 1994.

(i) NIOSH Method 2010, "Amines, Aliphatic," Issue 2, August 15, 1994, IBR approved for § 63.7732(g).

(ii) [Reserved]

(s) North American Electric Reliability Corporation, 1325 G Street, NW., Suite 600, Washington, DC 20005–3801, http://www.nerc.com, http://www.nerc.com/files/EOP0002-3_1.pdf.

(1) North American Electric Reliability Corporation Reliability Standard EOP–002–3, Capacity and Energy Emergencies, adopted August 5, 2010, IBR approved for § 63.6640(f).

(2) [Reserved]

(t) Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, http://www.tappi.org.

(1) TAPPI T 266, Determination of Sodium, Calcium, Copper, Iron, and Manganese in Pulp and Paper by Atomic Absorption Spectroscopy (Reaffirmation of T 266 om-02), Draft No. 2, July 2006, IBR approved for table 6 to subpart DDDDD.

(2) [Reserved]

(u) Texas Commission on Environmental Quality (TCEQ) Library, Post Office Box 13087, Austin, Texas 78711–3087, telephone number (512) 239–0028, http://www.tceq.state.tx.us/assets/public/implementation/air/sip/sipdocs/2002-12-HGB/02046sipapp_ado.pdf.

(1) "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources," Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P:

Cooling Tower Monitoring, January 31, 2003, IBR approved for §§ 63.654(c) and (g), 63.655(i), 63.1086(e), 63.1089, 63.2490(d), 63.2525(r), and 63.11920.

(2) [Reserved]

Editorial Note

Editorial Note: For Federal Register citations affecting § 63.14, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at *www.govinfo.gov.*

§ 63.15 Availability of information and confidentiality.

(a) *Availability of information.*

(1) With the exception of information protected through part 2 of this chapter, all reports, records, and other information collected by the Administrator under this part are available to the public. In addition, a copy of each permit application, compliance plan (including the schedule of compliance), notification of compliance status, excess emissions and continuous monitoring systems performance report, and title V permit is available to the public, consistent with protections recognized in section 503(e) of the Act.

(2) The availability to the public of information provided to or otherwise obtained by the Administrator under this part shall be governed by part 2 of this chapter.

(b) *Confidentiality.*

(1) If an owner or operator is required to submit information entitled to protection from disclosure under section 114(c) of the Act, the owner or operator may submit such information separately. The requirements of section 114(c) shall apply to such information.

(2) The contents of a title V permit shall not be entitled to protection under section 114(c) of the Act; however, information submitted as part of an application for a title V permit may be entitled to protection from disclosure.

§ 63.16 Performance Track Provisions.

(a) Notwithstanding any other requirements in this part, an affected source at any major source or any area source at a Performance Track member facility, which is subject to regular periodic reporting under any subpart of this part, may submit such periodic reports at an interval that is twice the length of the regular period specified in the applicable subparts; provided, that for sources subject to permits under 40 CFR part 70 or 71 no interval so calculated for any report of the results of any required monitoring may be less frequent than once in every six months.

(b) Notwithstanding any other requirements in this part, the modifications of reporting requirements in paragraph (c) of this section apply to any major source at a Performance Track member facility which is subject to requirements under any of the subparts of this part and which has:

(1) Reduced its total HAP emissions to less than 25 tons per year;

(2) Reduced its emissions of each individual HAP to less than 10 tons per year; and

(3) Reduced emissions of all HAPs covered by each MACT standard to at least the level required for full compliance with the applicable emission standard.

(c) For affected sources at any area source at a Performance Track member facility and which meet the requirements of paragraph (b)(3) of this section, or for affected sources at any major source that meet the requirements of paragraph (b) of this section:

(1) If the emission standard to which the affected source is subject is based on add-on control technology, and the affected source complies by using add-on control technology, then all required reporting elements in the periodic report may be met through an annual certification that the affected source is meeting the emission standard by continuing to use that control technology. The affected source must continue to meet all relevant monitoring and recordkeeping requirements. The compliance certification must meet the requirements delineated in Clean Air Act section 114(a)(3).

(2) If the emission standard to which the affected source is subject is based on add-on control technology, and the affected source complies by using pollution prevention, then all required reporting elements in the periodic report may be met through an annual certification that the affected source is continuing to use pollution prevention to reduce HAP emissions to levels at or below those required by the applicable emission standard. The affected source must maintain records of all calculations that demonstrate the level of HAP emissions required by the emission standard as well as the level of HAP emissions achieved by the affected source. The affected source must continue to meet all relevant monitoring and recordkeeping requirements. The compliance certification must meet the requirements delineated in Clean Air Act section 114(a)(3).

(3) If the emission standard to which the affected source is subject is based on pollution prevention, and the affected source complies by using pollution prevention and reduces emissions by an additional 50 percent or greater than required by the applicable emission standard, then all required reporting elements in the periodic report may be met through an annual certification that the affected source is continuing to use pollution prevention to reduce HAP emissions by an additional 50 percent or greater than required by the applicable emission standard. The affected source must maintain records of all calculations that demonstrate the level of HAP emissions required by the emission standard as well as the level of HAP emissions achieved by the affected source. The affected source must continue to meet all relevant monitoring and recordkeeping requirements. The compliance certification must meet the requirements delineated in Clean Air Act section 114(a)(3).

(4) Notwithstanding the provisions of paragraphs (c)(1) through (3), of this section, for sources subject to permits under 40 CFR part 70 or 71, the results of any required monitoring and recordkeeping must be reported not less frequently than once in every six months.

Table 1 to Subpart A of Part 63 - Detection Sensitivity Levels (grams per hour)

Monitoring frequency per subpart[a]	Detection sensitivity level
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

[a] When this alternative work practice is used to identify leaking equipment, the owner or operator must choose one of the monitoring frequencies listed in this table, in lieu of the monitoring frequency specified in

the applicable subpart. Bi-monthly means every other month. Semi-quarterly means twice per quarter. Monthly means once per month.

Appendix E. 40 CFR Part 63, Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.*

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.*

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.*

(1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

§63.6595 When do I have to comply with this subpart?

(a) *Affected sources.*

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

Emission and Operating Limitations

§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise

apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c)[reserved]

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

General Compliance Requirements

§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results,

review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

Testing and Initial Compliance Requirements

§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of

greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq. 3)$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq. 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable

performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either

paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the

engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

Continuous Compliance Requirements

§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) [reserved]

(iii) [reserved]

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Notifications, Reports, and Records

§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than

July 16, 2008, or no later than 120 days after the source becomes subject to this subpart, whichever is later.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40

CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) [reserved]

(vi) [reserved]

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §63.13.

§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purpose specified in § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

Other Requirements and Information

§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an

existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.,* as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with

the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes “rich” glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The “lean” glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, and volatile organic compounds (VOC) into CO_2, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located

within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2 until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a	

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI	Limit concentration of CO in the	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
stationary RICE 100≤HP≤300 HP	stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
or less per calendar year.[2]	1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary	Install NSCR to reduce HAP	

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]

For each . . .	Complying with the requirement to . . .	You must . . .
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§ 63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter*and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A–1, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A–4.
		ii. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM D6522–00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device; and	(2) ASTM D6522–00 (Reapproved 2005)[123] (heated probe not necessary) or method 10 of	(c) The CO concentration must be at 15 percent O_2, dry basis.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
			40 CFR part 60, appendix A–4	
		iv. Measure moisture content at the inlet and outlet of the control device as needed to determine CO and O_2 concentrations on a dry basis	(3) Method 4 of 40 CFR part 60, appendix A–3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03[13]	(d) Measurements to determine moisture content must be made at the same time and location as the measurements for CO concentration.
2. 4SRB stationary RICE	a. Reduce formaldehyde or THC emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, THC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter*and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM D6522–00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device as needed to determine formaldehyde or THC and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A–3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03[13]	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[13] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating	(4) (1) Method 25A,	(e) THC concentration must be at 15

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	reported as propane, of 40 CFR part 60, appendix A–7	percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter*and* the sampling port location meets the two and half-diameter criterion of section 11.1.1 of method 1 of 40 CFR part 60, appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to section 8.1.2 of method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A–2, or ASTM D6522–00 (Reapproved 2005)[13] (heated probe not necessary)	(b) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location as needed to determine formaldehyde or CO and O_2 concentrations on a dry basis; and	(2) Method 4 of 40 CFR part 60, appendix A–3, or method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03[13]	(c) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(3) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[13] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(d) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
		v. Measure CO at the exhaust of the stationary RICE	(4) Method 10 of 40 CFR part 60, appendix A–4, ASTM D6522–00 (2005),[13] method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03[13]	(e) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[1] You may also use methods 3A and 10 as options to ASTM–D6522–00 (2005).
[2] You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.
[3] Incorporated by reference, see § 63.14.

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP		monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and	a. Limit the concentration of formaldehyde in the stationary RICE exhaust	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	and not using oxidation catalyst or NSCR	ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or	i. Semiannually according to the requirements in §63.6650(b).
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate for the purposes specified in § 63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and	Yes	Subpart ZZZZ specifies test methods at

General provisions citation	Subject of citation	Applies to subpart	Explanation
	reduction of data		§63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to

General provisions citation	Subject of citation	Applies to subpart	Explanation
			COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of

General provisions citation	Subject of citation	Applies to subpart	Explanation
			performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.9(k)	Electronic reporting procedures	Yes	Only as specified in §63.9(j).
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782-44-7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate*.* The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check*.* The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration*.* The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150

percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the "sample conditioning phase" once per minute until constant readings are obtained. Then begin the "measurement data phase" and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ±3 percent of the up-scale gas value or ±1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ±0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this “sample conditioning phase” once per minute until readings are constant for at least two minutes. Then begin the “measurement data phase” and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the “measurement data phase” readings from the reported standard gas value must be less than or equal to ±5 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single “measurement data phase” reading must be less than or equal to ±2 percent or ±1 ppm for CO or ±0.5 percent O_2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the “measurement data phase”.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the "measurement data phase". The maximum allowable deviation from the mean for each of the individual readings is ±2 percent, or ±1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ±2 percent *or* ±1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ±5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average "measurement data phase" CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ±3 percent or ±1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) "Development of an Electrochemical Cell Emission Analyzer Test Protocol", Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) “Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers”, EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) “ICAC Test Protocol for Periodic Monitoring”, EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) “Code of Federal Regulations”, Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

Table 1: Appendix A—Sampling Run Data.

Facility_____ Engine I.D._____ Date_____											
Run Type:	(_)		(_)		(_)		(_)				
(X)	Pre-Sample Calibration		Stack Gas Sample		Post-Sample Cal. Check		Repeatability Check				
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO			
Sample Cond. Phase											
”											
”											
”											
”											
Measurement Data Phase											
”											
”											
”											
”											
”											
”											
”											
”											
”											
”											

Facility_____ Engine I.D._____ Date_____											
Run Type:	(_)			(_)			(_)			(_)	
(X)	Pre-Sample Calibration			Stack Gas Sample			Post-Sample Cal. Check			Repeatability Check	
Mean											
Refresh Phase											
”											
”											
”											
”											

Appendix F. Transport Rule (TR) Trading Program Title V Requirements

Description of TR Monitoring Provisions

The TR subject unit(s), and the unit-specific monitoring provisions at this source, are identified in the following table(s). These unit(s) are subject to the requirements for the TR NO_X Annual Trading Program and the TR SO_2 Group 2 Trading Program.

EQUI 1					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2			----------	x	
NO_X		----------		x	
Heat input			----------	x	

EQUI 2					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2			----------	x	
NO_X		----------		x	
Heat input			----------	x	

EQUI 3

Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2			----------	x	
NO_X		----------		x	
Heat input			----------	x	

EQUI 4					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2			----------	x	
NO_X		----------		x	
Heat input			----------	x	

EQUI 7					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2		x	----------		
NO_X		----------	x		

Heat input		x	----------		

EQUI 8					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, subpart B (for SO_2 monitoring) and 40 CFR part 75, subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, subpart E
SO_2		x	----------		
NO_X		----------	x		
Heat input		x	----------		

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR §§97.430 through 97.435 (TR NO_X Annual Trading Program) and 40 CFR §§ 97.730 through 97.735 (TR SO_2 Group 2 Trading Program), as applicable. The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable TR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR §§ 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, subpart E and 40 CFR § 75.66 and 40 CFR § 97.435 (TR NO_X Annual Trading Program) and 40 CFR § 97.735 (TR SO_2 Group 2 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR §§ 97.430 through 97.434 (TR NO_X Annual Trading Program) and 40 CFR Section §§ 97.730 through 97.734 (TR SO_2 Group 2 Trading Program), as applicable, must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR § 75.66 and 40 CFR § 97.435 (TR NO_X Annual Trading Program) and 40 CFR § 97.735 (TR SO_2 Group 2 Trading Program), as applicable. The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit(s) included above meet the requirement of 40 CFR §§ 97.430 through 97.434 (TR NO_X Annual Trading Program) and 40 CFR §§ 97.730 through 97.734 (TR SO_2 Group 2 Trading Program), as applicable.

Appendix G. 40 CFR Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of § 60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C, except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 1039.102, 1039.104, 1039.105, 1039.107, and 1039.115 and 40 CFR part 1039, appendix I, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement,

power density, and maximum engine power if the engines will be used solely in either or both of the following locations:

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

(h) Stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with auxiliary emission control devices (AECDs) as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The Tier 2 emission standards for new nonroad CI engines for the appropriate rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 for model year 2007 engines; and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a rated power greater than or equal to 37 KW (50 HP), the Tier 2 or Tier 3 emission standards for new nonroad CI engines for the same rated power as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the Tier 2 emission standards as described in 40 CFR part 1039, appendix I, for all pollutants and the smoke standards as specified in 40 CFR 1039.105.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the appropriate Tier 2 emission standards for new marine CI engines as described in 40 CFR part 1042, appendix I, for all pollutants, for the same displacement and rated power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI ICE identified in paragraphs (a) and (c) of this section may be certified to the provisions of 40 CFR part 1042 for commercial engines that are applicable for the engine's model year, displacement, power density, and maximum engine power if the engines will be used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section. Engines that would be subject to the Tier 4 standards in 40 CFR part 1042 that are used solely in either or both of the locations identified in paragraphs (g)(1) and (2) of this section may instead continue to be certified to the appropriate Tier 3 standards in 40 CFR part 1042.

(1) Remote areas of Alaska; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

§ 60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§ 60.4201 and 60.4202 during the certified emissions life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in § 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in § 60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

(f) Owners and operators of stationary CI ICE certified to the standards in 40 CFR part 1039 and equipped with AECDs as specified in 40 CFR 1039.665 must meet the Tier 1 certification emission standards for new nonroad CI engines in 40 CFR part 1039, appendix I, while the AECD is activated during a qualified emergency situation. A qualified emergency situation is defined in 40 CFR 1039.665. When the qualified emergency situation has ended and the AECD is deactivated, the engine must resume meeting the otherwise applicable emission standard specified in this section.

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the Tier 1 emission standards in 40 CFR part 1042, appendix I.

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in § 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in § 60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§ 60.4204 and 60.4205 over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) [Reserved]

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder must use diesel fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under § 60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§ 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in § 60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in § 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §§ 60.4201(a) through (c) and 60.4202(a), (b), and (d) using the certification procedures required in 40 CFR part 1039, subpart C, and must test their engines as specified in 40 CFR part 1039. For the purposes of this subpart, engines certified to the standards in Table 1 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I. For the purposes of this subpart, engines certified to the standards in Table 4 to this subpart shall be subject to the same certification procedures required for engines certified to the Tier 1 standards in 40 CFR part 1039, appendix I, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §§ 60.4201(d) and (e) and 60.4202(e) and (f) using the certification procedures required in 40 CFR part 1042, subpart C, and must test their engines as specified in 40 CFR part 1042.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135 and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR part 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family

and/or may include any such family containing stationary engines in the averaging, banking, and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in § 60.4202 but does not meet all the emission standards for non-emergency engines in § 60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of § 60.4201 or § 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

(j) Stationary CI ICE manufacturers may equip their stationary CI internal combustion engines certified to the emission standards in 40 CFR part 1039 with AECDs for qualified emergency situations according to the requirements of 40 CFR 1039.665. Manufacturers of stationary CI ICE equipped with AECDs as allowed by 40 CFR 1039.665 must meet all the requirements in 40 CFR 1039.665 that apply to manufacturers. Manufacturers must document that the engine complies with the Tier 1 standard in 40 CFR part 1039, appendix I, when the AECD is activated. Manufacturers must provide any relevant testing, engineering analysis, or other information in sufficient detail to support such statement when applying for certification (including amending an existing certificate) of an engine equipped with an AECD as allowed by 40 CFR 1039.665.

(k) Manufacturers of any size may certify their emergency stationary CI internal combustion engines under this section using assigned deterioration factors established by EPA, consistent with 40 CFR 1039.240 and 1042.240.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR part 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(a) or § 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified to emission standards for the same model year and maximum engine power as described in 40 CFR parts 1039 and 1042, as applicable. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in § 60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(b) or § 60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in § 60.4205(c), you must comply by purchasing an engine certified to the emission standards in § 60.4204(b), or § 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in § 60.4204(c) or § 60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in § 60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in § 60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in § 60.4204(e) or § 60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4204(e) or § 60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4212 or § 60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (f)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency

situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) [reserved]

(iii) [reserved]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

(h) The requirements for operators and prohibited acts specified in 40 CFR 1039.665 apply to owners or operators of stationary CI ICE equipped with AECDs for qualified emergency situations as allowed by 40 CFR 1039.665.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder. Alternatively, stationary CI ICE that are complying with Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or with Tier 2

emission standards as described in 40 CFR part 1042, appendix I, may follow the testing procedures specified in § 60.4213, as appropriate.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE subject to Tier 2 or Tier 3 emission standards as described in 40 CFR part 1039, appendix I, or Tier 2 emission standards as described in 40 CFR part 1042, appendix I, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (\text{STD}) \quad \text{(Eq. 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR part 1039 or 1042, as applicable.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in § 60.4204(a), § 60.4205(a), or § 60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in § 60.4204(a), § 60.4205(a), or § 60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in § 60.4204(a), § 60.4205(a), or § 60.4205(c) may follow the testing procedures specified in § 60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in § 60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\ O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

$1.912x10^{-3}$ = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) [reserved]

(vi) [reserved]

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

(e) Owners or operators of stationary CI ICE equipped with AECDs pursuant to the requirements of 40 CFR 1039.665 must report the use of AECDs as required by 40 CFR 1039.665(e).

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§ 60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in § 60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in remote areas of Alaska may meet the requirements of this subpart by manufacturing and installing engines meeting the Tier 2 or Tier 3 emission standards described in 40 CFR part 1042 for the same model year, displacement, and maximum engine power, as appropriate, rather than the otherwise applicable requirements of 40 CFR part 1039, as indicated in §§ 60.4201(f) and 60.4202(g).

(c) Manufacturers, owners, and operators of stationary CI ICE that are located in remote areas of Alaska may choose to meet the applicable emission standards for emergency engines in §§ 60.4202 and 60.4205, and not those for non-emergency engines in §§ 60.4201 and 60.4204, except that for 2014 model year and later nonemergency CI ICE, the owner or operator of any such engine must have that engine certified as meeting at least the Tier 3 PM standards identified in appendix I of 40 CFR part 1039 or in 40 CFR 1042.101.

(d) The provisions of § 60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in remote areas of Alaska.

(e) The provisions of § 60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and § 60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in remote areas of Alaska from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in § 60.4204 or § 60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

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

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for certified emissions life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 1042.101(e).

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of “manufacturer” in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Remote areas of Alaska means areas of Alaska that meet either paragraph (1) or (2) of this definition.

(1) Areas of Alaska that are not accessible by the Federal Aid Highway System (FAHS).

(2) Areas of Alaska that meet all of the following criteria:

(i) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary CI ICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary CI ICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the source is less than 12 megawatts, or the stationary CI ICE is used exclusively for backup power for renewable energy.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at

an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Table 1 to Subpart IIII of Part 60 - Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§ 60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	**Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007-2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)**				
	NMHC + NO_X	**HC**	**NO_X**	**CO**	**PM**
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60 - Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in § 60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008 +	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008 +	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008 +	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60 - Certification Requirements for Stationary Fire Pump Engines

As stated in § 60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to § 60.4202(d)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

Table 4 to Subpart IIII of Part 60 - Emission Standards for Stationary Fire Pump Engines

[As stated in §§ 60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011 +	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011 +	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011 +[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010 +[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008 +	6.4 (4.8)		0.20 (0.15)

[1] For model years 2011-2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.

[2] For model years 2010-2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.

[3] In model years 2009-2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60 - Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in § 60.4210(f) and the recordkeeping requirements in § 60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60 - Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in § 60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1] Engine speed: ±2 percent of point.

[2] Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60 - Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

As stated in § 60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:

Each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥ 30 liters per	a. Reduce NO_X emissions by 90 percent or more;	i. Select the sampling port location and number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the

Each	Complying with the requirement to	You must	Using	According to the following requirements
cylinder				measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_X concentration.
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points

Each	Complying with the requirement to	You must	Using	According to the following requirements
				according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see § 60.17)	(d) NO_X concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.

Each	Complying with the requirement to	You must	Using	According to the following requirements
	internal combustion engine exhaust			
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A-3	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the exhaust of the stationary internal combustion engine.	(4) Method 5 of 40 CFR part 60, appendix A-3	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60 - Applicability of General Provisions to Subpart IIII

[As stated in § 60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4219.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4214(a).
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Except that § 60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	
§ 60.19	General notification and reporting requirements	Yes	

Appendix H. Fugitive Dust Control Plan

Fugitive Dust Control Plan Prepared for Xcel Energy - Blue Lake November 2023

Abbreviations

FDCP or Plan	Fugitive Dust Control Plan
MPCA	Minnesota Pollution Control Agency
mph	miles per hour
Facility	Xcel Energy - Blue Lake

Introduction

The objective of this Fugitive Dust Control Plan (Plan or FDCP) is to describe the dust control measures that will be implemented during the operation of the Xcel Blue Lake Facility (Facility). The Facility is a power plant that includes fuel delivery traffic on paved roads. The Plan provides a description of the applicable fugitive dust regulations, and the planned measures for mitigating dust emissions from this source. The Plan will be used as a living document and will be revised and updated as needed to support the Facility.

Sources of Fugitive Dust

This Plan is specific to fugitive dust generated from paved roads.

Applicable Regulations

The Project is subject to the state of Minnesota regulations to control fugitive dust emissions under Minn. Rules 7011.0150, which is a general prohibition against generating excessive fugitive dust:

A. No person shall cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne.

B. *No person shall cause or permit a building or its appurtenances or* ***a road****, or a driveway, or an open area to be constructed,* ***used****, repaired, or demolished* ***without applying all such reasonable measures as may be required to prevent particulate matter from becoming airborne. All persons shall take reasonable precautions to prevent the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate.*** *The commissioner may require such reasonable measures as may be necessary to prevent particulate matter from becoming airborne including, but not limited to, paving or frequent* ***clearing of roads****, driveways, and parking lots; application of dust-free surfaces;* ***application of water****; and the planting and maintenance of vegetative ground cover.* ***[emphasis added]***

Xcel developed the dust control measures for the Project based on this regulation.

A major air permit amendment application for the Blue Lake Conversion Project (the Project) was originally submitted in January 2023 and resubmitted in November 2023. Because the Project will trigger the Prevention of Significant Deterioration (PSD) requirements for PM, PM_{10}, $PM_{2.5}$, a Best Available Control Technology (BACT) Analysis was conducted for the paved roads. The BACT determination is summarized in the following table and this Plan has been developed to meet this requirement.

Proposed BACT	Compliance Demonstration
Fugitive Dust Control Plan	Follow procedures outlined in the fugitive dust control plan, including daily visible emission checks when fuel is being delivered.

Fugitive Dust Control Implementation
The mitigation measures to minimize fugitive dust emissions may include activities like sweeping, watering, and speed limits. Control measures operational-related activities are described in the Fugitive Dust Mitigation Measures section of this Plan.

Fugitive Dust Monitoring
Frequency
Dust control personnel will monitor the paved roads at least once per operating day (e.g., on days in which fuel deliveries are occurring). The frequency of fugitive dust monitoring may be adjusted, if necessary, to prevent and mitigate fugitive dust creation.

In addition to the routing monitoring, Xcel will evaluate fugitive dust control measures and the Plan on a routine and as-needed basis. The Plan will be reviewed at least annually, and updates will be made to document any new control measures implemented over the past year, any changes to fugitive dust sources and their levels of emissions, and whether any further changes to the fugitive dust control strategy are needed.

Action Trigger
During daily fugitive dust inspections, visible fugitive dust from the paved roads will trigger one or more of the following actions:

- Evaluate and document the control measure(s) currently in use;
- Possible reapplication or enhancement of the measure(s); and
- Temporary curtailment of the dust generating activity, if needed, based on weather conditions.

The observation of visible emissions does not, determinately, demonstrate noncompliance with any applicable requirement. It is a signal to investigate and, if necessary, take reasonable and appropriate corrective action.

Fugitive Dust Mitigation Measures
The following control measures will apply to potential fugitive dust sources from operational activities:

- Minimize extraneous vehicle travel on fuel delivery routes through signage and training, except for activities where traffic on those routes has been approved;
- Facility staff will monitor visible dust and control measures daily when fuel is being delivered;
- Speed limits for traffic on paved and unpaved roads will be a maximum of 15 miles per hour (mph);
- Traffic will follow posted speed limits on any paved state, county, or local roads; and
- Signage and training will be used to establish the Project speed limits.

Paved Roads
The following control measures will apply to potential fugitive dust sources related to paved roads.

- Site speed limit (15 miles per hour);

- Inspect road surface for excess silt, mud, etc.;
- Use of a street sweeper and/or water to remove accumulated dust if indicated by inspection results and/or observed visible emissions;
- If visible emissions occur, conduct additional street sweeping or apply water as a dust suppressant.

Training

An essential part of the implementation of the Plan is appropriate training for the personnel involved. Xcel will provide training for contractors, drivers and personnel responsible for dust control at the facility during new employee training and at an annual refresher training and periodically as needed for new hires. Xcel will assign dust control personnel for the facility to implement the dust control measures specified in this Plan and in the air permit issued by the Minnesota Pollution Control Agency (MPCA). Facility staff will be responsible for monitoring the implementation dust control measures. They will also be responsible for maintaining proper documentation.

Training will cover the following subjects as needed for individual levels of responsibility:

- Employee responsibilities;
- Dust control measures;
- Corrective actions;
- Dust observation and visibility training;
- Weather observations;
- Forms and record keeping; and
- Reporting.

Responsibilities of the environmental compliance staff, or designated facility staff, will be:

- Leading an annual review of dust control measures for operational sources in this Plan and any changes implemented since the last annual review;
- Monitoring visible fugitive dust daily when fuel is being delivered, such that sufficient dust control measures, can be applied expeditiously when necessary;
- Tracking operational activities so that daily visible emissions observations are performed when fuel is being delivered; and
- Documenting control measure implementation as described in the Fugitive Dust Mitigation Measures section.

Recordkeeping

Inspections of operational activities that are potential sources of fugitive dust will occur daily when fuel is being delivered. The environmental compliance staff, or designated facility staff, will be responsible for recording the following information on a daily basis:

- Weather conditions (temperature and precipitation);
- Deployment of any road sweepers and/or watering;
- Cases where visible dust inspections required implementation of control measures; and
- Areas treated with additional control measures.

The facility will retain these records for a period of at least five years from the date the records are generated.

Additional details regarding recordkeeping requirements for this Plan may be developed during the permitting process with MPCA. This Plan will be updated, if needed, once the air permit and other plans have been finalized.

Appendix I. General Public Preclusion Plan

resourceful. naturally.
engineering and environmental consultants

BARR

Technical Memorandum

To: MPCA Air Quality Permit Document Coordinator
From: Jenni Koenen
Subject: Xcel Energy - Blue Lake General Public Preclusion Plan
Date: October 14, 2022
Project: Blue Lake Conversion Project Air Dispersion Modeling Protocol
c: Hannah Mathers, Xcel Energy
Nicholas Gamble, Xcel Energy

Xcel Energy – Blue Lake (Xcel Blue Lake) is submitting an air dispersion modeling protocol to satisfy the PSD major modification requirements for the Blue Lake Conversion Project ("the Project") which includes the following updates at the facility:

- Retire the four Turbodyne CTs (EQUI 1, EQUI 2, EQUI 3, and EQUI 4)
- Modify the synthetic minor emission limits as presented in the facility air permit (COMG 2) for the two General Electric CTs (EQUI 7 and EQUI 8) to allow increased utilization
- Install three (3) 9.37 MW Wartsila dual fuel (natural gas and diesel) internal combustion engine generators
- Install two (2) diesel-fired emergency generators.

As part of this protocol submittal, this General Public Preclusion Plan (GPPP) provides specifics on the ambient air boundary represented by Xcel Blue Lake's current fence line and other measures preventing the public from entering the modeled ambient air boundary.

Ambient Air Boundary and Public Preclusion Plan

Figure 1 shows the modeled ambient air boundary which represents the location of the facility operational fence line. The boundary consists of an 8-foot-tall fence completely containing the entire Xcel Blue Lake facility. The entrance to the facility is at the end of the plant owned extension of 70th Street where there is a locked gate restricting vehicles and foot traffic access to the property, allowing only employee traffic, material delivery, and other authorized visitors.

In addition to the existing fence line, a gate is located after the fork on 70th Street south of the railroad tracks at the property boundary and the beginning of the private extension of 70th Street with a sign indicating the entrance to the Xcel Blue Lake and a "No Trespassing" private property sign posted to curb unauthorized access. Figure 2 is an image from Google Maps Streetview showing the gate identified in Figure 1. Security cameras and periodic perimeter patrols provide additional enforcement measures. Security cameras will be appropriately monitored and maintained by plant staff and Xcel's Enterprise Command Center.

Conclusion

The information provided in this memo is to support and affirm the GPPP for Xcel Blue Lake for purposes of NAAQS and increment modeling. The measures described will prevent the public from accessing its facility.

To: MPCA Air Quality Permit Document Coordinator
From: Jenni Koenen
Subject: Xcel Energy - Blue Lake General Public Preclusion Plan
Date: October 14, 2022
Page: 2

Figure 1 Xcel Energy Blue Lake Plant Fence Line



Figure 2 Xcel Energy Blue Lake Plant North Entrance Gate and Posted Signage



Appendix J. Modeling Parameters

Point Source Parameters

1-hr NO2 NAAQS

Stack ID	Description	Easting	Northing	Height	Exit Temp	Exit Vel	Flow Rate	Emiss. Rate
		(X1, m)	(Y1, m)	(m)	(K)	(m/s)	(acfm)	(lb/hr)
STRU 16	Combustion Turbine 1	466,000.0	4,959,206.0	15.85	728.71	37.58	1,360,000	NA
STRU 17	Combustion Turbine 2	465,988.0	4,959,206.0	15.85	728.71	37.58	1,360,000	NA
STRU 18	Combustion Turbine 3	465,968.0	4,959,207.0	15.85	728.71	37.58	1,360,000	NA
STRU 19	Combustion Turbine 4	465,954.0	4,959,207.0	15.85	783.15	37.58	1,360,000	NA
STRU 12	Combustion Turbine 7	465,895.0	4,959,202.0	15.24	869.26	49.30	2,388,000	73.51
STRU 13	Combustion Turbine 8	465,841.0	4,959,202.0	15.24	869.26	49.30	2,388,000	73.51
STRU 24	Engine Generator 1	465,933.3	4,959,185.1	28.956	604.82	27.60	68,281	10.86
STRU 25	Engine Generator 2	465,938.4	4,959,185.1	28.956	604.82	27.60	68,281	10.86
STRU 26	Engine Generator 3	465,943.6	4,959,185.0	28.956	604.82	27.60	68,281	10.86

Annual NO2 NAAQS

Stack ID	Description	Easting	Northing	Height	Exit Temp	Exit Vel	Flow Rate	Emiss. Rate
		(X1, m)	(Y1, m)	(m)	(K)	(m/s)	(acfm)	(lb/hr)
STRU 16	Combustion Turbine 1	466,000.0	4,959,206.0	15.85	728.71	37.58	1,360,000	835.42
STRU 17	Combustion Turbine 2	465,988.0	4,959,206.0	15.85	728.71	37.58	1,360,000	865.69
STRU 18	Combustion Turbine 3	465,968.0	4,959,207.0	15.85	728.71	37.58	1,360,000	1035.37
STRU 19	Combustion Turbine 4	465,954.0	4,959,207.0	15.85	783.15	37.58	1,360,000	1160.17
STRU 12	Combustion Turbine 7	465,895.0	4,959,202.0	15.24	869.26	49.30	2,388,000	71.03
STRU 13	Combustion Turbine 8	465,841.0	4,959,202.0	15.24	869.26	49.30	2,388,000	71.03
STRU 24	Engine Generator 1	465,933.3	4,959,185.1	28.956	604.82	27.60	68,281	14.46
STRU 25	Engine Generator 2	465,938.4	4,959,185.1	28.956	604.82	27.60	68,281	14.46
STRU 26	Engine Generator 3	465,943.6	4,959,185.0	28.956	604.82	27.60	68,281	14.46

24-hr PM2.5 NAAQS

Stack ID	Description	Easting	Northing	Height	Exit Temp	Exit Vel	Flow Rate	Emiss. Rate
		(X1, m)	(Y1, m)	(m)	(K)	(m/s)	(acfm)	(lb/hr)
STRU 16	Combustion Turbine 1	466,000.0	4,959,206.0	15.85	728.71	37.58	1,360,000	NA
STRU 17	Combustion Turbine 2	465,988.0	4,959,206.0	15.85	728.71	37.58	1,360,000	NA
STRU 18	Combustion Turbine 3	465,968.0	4,959,207.0	15.85	728.71	37.58	1,360,000	NA
STRU 19	Combustion Turbine 4	465,954.0	4,959,207.0	15.85	783.15	37.58	1,360,000	NA

STRU 12	Combustion Turbine 7	465,895.0	4,959,202.0	15.24	869.26	49.30	2,388,000	13.48
STRU 13	Combustion Turbine 8	465,841.0	4,959,202.0	15.24	869.26	49.30	2,388,000	13.48
STRU 24	Engine Generator 1	465,933.3	4,959,185.1	28.956	604.82	27.60	68,281	4.76
STRU 25	Engine Generator 2	465,938.4	4,959,185.1	28.956	604.82	27.60	68,281	4.76
STRU 26	Engine Generator 3	465,943.6	4,959,185.0	28.956	604.82	27.60	68,281	4.76

Annual PM2.5 NAAQS

Stack ID	Description	Easting	Northing	Height	Exit Temp	Exit Vel	Flow Rate	Emiss. Rate
		(X1, m)	(Y1, m)	(m)	(K)	(m/s)	(acfm)	(lb/hr)
STRU 16	Combustion Turbine 1	466,000.0	4,959,206.0	15.85	728.71	37.58	1,360,000	NA
STRU 17	Combustion Turbine 2	465,988.0	4,959,206.0	15.85	728.71	37.58	1,360,000	NA
STRU 18	Combustion Turbine 3	465,968.0	4,959,207.0	15.85	728.71	37.58	1,360,000	NA
STRU 19	Combustion Turbine 4	465,954.0	4,959,207.0	15.85	783.15	37.58	1,360,000	NA
STRU 12	Combustion Turbine 7	465,895.0	4,959,202.0	15.24	869.26	49.30	2,388,000	13.48
STRU 13	Combustion Turbine 8	465,841.0	4,959,202.0	15.24	869.26	49.30	2,388,000	13.48
STRU 24	Engine Generator 1	465,933.3	4,959,185.1	28.956	604.82	27.60	68,281	4.78
STRU 25	Engine Generator 2	465,938.4	4,959,185.1	28.956	604.82	27.60	68,281	4.78
STRU 26	Engine Generator 3	465,943.6	4,959,185.0	28.956	604.82	27.60	68,281	4.78

Volume Source Parameters
24-hr PM2.5 NAAQS

FUGI ID	AERMOD ID	Easting	Northing	SigmaY	SigmaZ	LengthX	Emiss. Rate
		(X1, m)	(Y1, m)	(m)	(m)	(m)	(lb/hr)
FUGI 1	PVRD001	466,033.907	4,959,305.220	4.65	3.62	10	2.15E-04
FUGI 1	PVRD002	466,023.907	4,959,305.279	4.65	3.62	10	2.15E-04
FUGI 1	PVRD003	466,013.908	4,959,305.338	4.65	3.62	10	2.15E-04
FUGI 1	PVRD004	466,003.908	4,959,305.397	4.65	3.62	10	2.15E-04
FUGI 1	PVRD005	465,993.908	4,959,305.455	4.65	3.62	10	2.15E-04
FUGI 1	PVRD006	465,983.908	4,959,305.514	4.65	3.62	10	2.15E-04
FUGI 1	PVRD007	465,973.908	4,959,305.573	4.65	3.62	10	2.15E-04
FUGI 1	PVRD008	465,963.908	4,959,305.632	4.65	3.62	10	2.15E-04
FUGI 1	PVRD009	465,953.909	4,959,305.691	4.65	3.62	10	2.15E-04
FUGI 1	PVRD010	465,943.909	4,959,305.749	4.65	3.62	10	2.15E-04
FUGI 1	PVRD011	465,933.909	4,959,305.808	4.65	3.62	10	2.15E-04
FUGI 1	PVRD012	465,930.564	4,959,297.021	4.65	3.62	10	2.15E-04
FUGI 1	PVRD013	465,929.944	4,959,287.040	4.65	3.62	10	2.15E-04

FUGI 1	PVRD014	465,929.324	4,959,277.059	4.65	3.62	10	2.15E-04
FUGI 1	PVRD015	465,928.704	4,959,267.078	4.65	3.62	10	2.15E-04
FUGI 1	PVRD016	465,928.332	4,959,257.089	4.65	3.62	10	2.15E-04
FUGI 1	PVRD017	465,928.244	4,959,247.089	4.65	3.62	10	2.15E-04
FUGI 1	PVRD018	465,928.157	4,959,237.090	4.65	3.62	10	2.15E-04
FUGI 1	PVRD019	465,928.069	4,959,227.090	4.65	3.62	10	2.15E-04
FUGI 1	PVRD020	465,927.982	4,959,217.090	4.65	3.62	10	2.15E-04
FUGI 1	PVRD021	465,927.895	4,959,207.091	4.65	3.62	10	2.15E-04
FUGI 1	PVRD022	465,927.807	4,959,197.091	4.65	3.62	10	2.15E-04
FUGI 1	PVRD023	465,938.893	4,959,195.088	4.65	3.62	10	2.15E-04
FUGI 1	PVRD024	465,948.893	4,959,195.088	4.65	3.62	10	2.15E-04
FUGI 1	PVRD025	465,958.893	4,959,195.088	4.65	3.62	10	2.15E-04
FUGI 1	PVRD026	465,968.893	4,959,195.088	4.65	3.62	10	2.15E-04
FUGI 1	PVRD027	465,978.222	4,959,193.279	4.65	3.62	10	2.15E-04
FUGI 1	PVRD028	465,984.183	4,959,186.090	4.65	3.62	10	2.15E-04
FUGI 1	PVRD029	465,983.480	4,959,176.118	4.65	3.62	10	2.15E-04
FUGI 1	PVRD030	465,983.405	4,959,166.118	4.65	3.62	10	2.15E-04
FUGI 1	PVRD031	465,983.329	4,959,156.118	4.65	3.62	10	2.15E-04
FUGI 1	PVRD032	465,981.918	4,959,146.403	4.65	3.62	10	2.15E-04
FUGI 1	PVRD033	465,976.675	4,959,138.544	4.65	3.62	10	2.15E-04
FUGI 1	PVRD034	465,967.220	4,959,135.562	4.65	3.62	10	2.15E-04
FUGI 1	PVRD035	465,957.220	4,959,135.693	4.65	3.62	10	2.15E-04
FUGI 1	PVRD036	465,947.221	4,959,135.824	4.65	3.62	10	2.15E-04
FUGI 1	PVRD037	465,937.222	4,959,135.954	4.65	3.62	10	2.15E-04
FUGI 1	PVRD038	465,927.223	4,959,136.085	4.65	3.62	10	2.15E-04
FUGI 1	PVRD039	465,917.224	4,959,136.216	4.65	3.62	10	2.15E-04
FUGI 1	PVRD040	465,907.225	4,959,136.346	4.65	3.62	10	2.15E-04
FUGI 1	PVRD041	465,897.226	4,959,136.477	4.65	3.62	10	2.15E-04
FUGI 1	PVRD042	465,887.226	4,959,136.607	4.65	3.62	10	2.15E-04
FUGI 1	PVRD043	465,877.227	4,959,136.738	4.65	3.62	10	2.15E-04
FUGI 1	PVRD044	465,867.228	4,959,136.869	4.65	3.62	10	2.15E-04
FUGI 1	PVRD045	465,857.229	4,959,136.999	4.65	3.62	10	2.15E-04
FUGI 1	PVRD046	465,847.230	4,959,137.130	4.65	3.62	10	2.15E-04
FUGI 1	PVRD047	465,837.231	4,959,137.273	4.65	3.62	10	2.15E-04
FUGI 1	PVRD048	465,827.233	4,959,137.473	4.65	3.62	10	2.15E-04
FUGI 1	PVRD049	465,817.385	4,959,138.075	4.65	3.62	10	2.15E-04

FUGI 1	PVRD050	465,810.027	4,959,144.700	4.65	3.62	10	2.15E-04
FUGI 1	PVRD051	465,806.894	4,959,154.177	4.65	3.62	10	2.15E-04
FUGI 1	PVRD052	465,807.741	4,959,164.141	4.65	3.62	10	2.15E-04
FUGI 1	PVRD053	465,808.587	4,959,174.105	4.65	3.62	10	2.15E-04
FUGI 1	PVRD054	465,809.434	4,959,184.069	4.65	3.62	10	2.15E-04
FUGI 1	PVRD055	465,816.931	4,959,188.650	4.65	3.62	10	2.15E-04
FUGI 1	PVRD056	465,826.928	4,959,188.416	4.65	3.62	10	2.15E-04
FUGI 1	PVRD057	465,836.925	4,959,188.182	4.65	3.62	10	2.15E-04
FUGI 1	PVRD058	465,846.923	4,959,187.948	4.65	3.62	10	2.15E-04
FUGI 1	PVRD059	465,856.920	4,959,187.714	4.65	3.62	10	2.15E-04
FUGI 1	PVRD060	465,866.917	4,959,187.480	4.65	3.62	10	2.15E-04
FUGI 1	PVRD061	465,876.915	4,959,187.246	4.65	3.62	10	2.15E-04
FUGI 1	PVRD062	465,886.912	4,959,187.013	4.65	3.62	10	2.15E-04
FUGI 1	PVRD063	465,896.909	4,959,186.779	4.65	3.62	10	2.15E-04
FUGI 1	PVRD064	465,906.906	4,959,186.545	4.65	3.62	10	2.15E-04
FUGI 1	PVRD065	465,916.904	4,959,186.311	4.65	3.62	10	2.15E-04
FUGI 1	PVRD066	465,926.272	4,959,187.728	4.65	3.62	10	2.15E-04

Annual PM2.5 NAAQS

FUGI ID	AERMOD ID	Easting	Northing	SigmaY	SigmaZ	LengthX	Emiss. Rate
		(X1, m)	(Y1, m)	(m)	(m)	(m)	(lb/hr)
FUGI 1	PVRD001	466,033.907	4,959,305.220	4.65	3.62	10	4.90E-05
FUGI 1	PVRD002	466,023.907	4,959,305.279	4.65	3.62	10	4.90E-05
FUGI 1	PVRD003	466,013.908	4,959,305.338	4.65	3.62	10	4.90E-05
FUGI 1	PVRD004	466,003.908	4,959,305.397	4.65	3.62	10	4.90E-05
FUGI 1	PVRD005	465,993.908	4,959,305.455	4.65	3.62	10	4.90E-05
FUGI 1	PVRD006	465,983.908	4,959,305.514	4.65	3.62	10	4.90E-05
FUGI 1	PVRD007	465,973.908	4,959,305.573	4.65	3.62	10	4.90E-05
FUGI 1	PVRD008	465,963.908	4,959,305.632	4.65	3.62	10	4.90E-05
FUGI 1	PVRD009	465,953.909	4,959,305.691	4.65	3.62	10	4.90E-05
FUGI 1	PVRD010	465,943.909	4,959,305.749	4.65	3.62	10	4.90E-05
FUGI 1	PVRD011	465,933.909	4,959,305.808	4.65	3.62	10	4.90E-05
FUGI 1	PVRD012	465,930.564	4,959,297.021	4.65	3.62	10	4.90E-05
FUGI 1	PVRD013	465,929.944	4,959,287.040	4.65	3.62	10	4.90E-05
FUGI 1	PVRD014	465,929.324	4,959,277.059	4.65	3.62	10	4.90E-05
FUGI 1	PVRD015	465,928.704	4,959,267.078	4.65	3.62	10	4.90E-05

FUGI 1	PVRD016	465,928.332	4,959,257.089	4.65	3.62	10	4.90E-05
FUGI 1	PVRD017	465,928.244	4,959,247.089	4.65	3.62	10	4.90E-05
FUGI 1	PVRD018	465,928.157	4,959,237.090	4.65	3.62	10	4.90E-05
FUGI 1	PVRD019	465,928.069	4,959,227.090	4.65	3.62	10	4.90E-05
FUGI 1	PVRD020	465,927.982	4,959,217.090	4.65	3.62	10	4.90E-05
FUGI 1	PVRD021	465,927.895	4,959,207.091	4.65	3.62	10	4.90E-05
FUGI 1	PVRD022	465,927.807	4,959,197.091	4.65	3.62	10	4.90E-05
FUGI 1	PVRD023	465,938.893	4,959,195.088	4.65	3.62	10	4.90E-05
FUGI 1	PVRD024	465,948.893	4,959,195.088	4.65	3.62	10	4.90E-05
FUGI 1	PVRD025	465,958.893	4,959,195.088	4.65	3.62	10	4.90E-05
FUGI 1	PVRD026	465,968.893	4,959,195.088	4.65	3.62	10	4.90E-05
FUGI 1	PVRD027	465,978.222	4,959,193.279	4.65	3.62	10	4.90E-05
FUGI 1	PVRD028	465,984.183	4,959,186.090	4.65	3.62	10	4.90E-05
FUGI 1	PVRD029	465,983.480	4,959,176.118	4.65	3.62	10	4.90E-05
FUGI 1	PVRD030	465,983.405	4,959,166.118	4.65	3.62	10	4.90E-05
FUGI 1	PVRD031	465,983.329	4,959,156.118	4.65	3.62	10	4.90E-05
FUGI 1	PVRD032	465,981.918	4,959,146.403	4.65	3.62	10	4.90E-05
FUGI 1	PVRD033	465,976.675	4,959,138.544	4.65	3.62	10	4.90E-05
FUGI 1	PVRD034	465,967.220	4,959,135.562	4.65	3.62	10	4.90E-05
FUGI 1	PVRD035	465,957.220	4,959,135.693	4.65	3.62	10	4.90E-05
FUGI 1	PVRD036	465,947.221	4,959,135.824	4.65	3.62	10	4.90E-05
FUGI 1	PVRD037	465,937.222	4,959,135.954	4.65	3.62	10	4.90E-05
FUGI 1	PVRD038	465,927.223	4,959,136.085	4.65	3.62	10	4.90E-05
FUGI 1	PVRD039	465,917.224	4,959,136.216	4.65	3.62	10	4.90E-05
FUGI 1	PVRD040	465,907.225	4,959,136.346	4.65	3.62	10	4.90E-05
FUGI 1	PVRD041	465,897.226	4,959,136.477	4.65	3.62	10	4.90E-05
FUGI 1	PVRD042	465,887.226	4,959,136.607	4.65	3.62	10	4.90E-05
FUGI 1	PVRD043	465,877.227	4,959,136.738	4.65	3.62	10	4.90E-05
FUGI 1	PVRD044	465,867.228	4,959,136.869	4.65	3.62	10	4.90E-05
FUGI 1	PVRD045	465,857.229	4,959,136.999	4.65	3.62	10	4.90E-05
FUGI 1	PVRD046	465,847.230	4,959,137.130	4.65	3.62	10	4.90E-05
FUGI 1	PVRD047	465,837.231	4,959,137.273	4.65	3.62	10	4.90E-05
FUGI 1	PVRD048	465,827.233	4,959,137.473	4.65	3.62	10	4.90E-05
FUGI 1	PVRD049	465,817.385	4,959,138.075	4.65	3.62	10	4.90E-05
FUGI 1	PVRD050	465,810.027	4,959,144.700	4.65	3.62	10	4.90E-05
FUGI 1	PVRD051	465,806.894	4,959,154.177	4.65	3.62	10	4.90E-05

FUGI 1	PVRD052	465,807.741	4,959,164.141	4.65	3.62	10	4.90E-05
FUGI 1	PVRD053	465,808.587	4,959,174.105	4.65	3.62	10	4.90E-05
FUGI 1	PVRD054	465,809.434	4,959,184.069	4.65	3.62	10	4.90E-05
FUGI 1	PVRD055	465,816.931	4,959,188.650	4.65	3.62	10	4.90E-05
FUGI 1	PVRD056	465,826.928	4,959,188.416	4.65	3.62	10	4.90E-05
FUGI 1	PVRD057	465,836.925	4,959,188.182	4.65	3.62	10	4.90E-05
FUGI 1	PVRD058	465,846.923	4,959,187.948	4.65	3.62	10	4.90E-05
FUGI 1	PVRD059	465,856.920	4,959,187.714	4.65	3.62	10	4.90E-05
FUGI 1	PVRD060	465,866.917	4,959,187.480	4.65	3.62	10	4.90E-05
FUGI 1	PVRD061	465,876.915	4,959,187.246	4.65	3.62	10	4.90E-05
FUGI 1	PVRD062	465,886.912	4,959,187.013	4.65	3.62	10	4.90E-05
FUGI 1	PVRD063	465,896.909	4,959,186.779	4.65	3.62	10	4.90E-05
FUGI 1	PVRD064	465,906.906	4,959,186.545	4.65	3.62	10	4.90E-05
FUGI 1	PVRD065	465,916.904	4,959,186.311	4.65	3.62	10	4.90E-05
FUGI 1	PVRD066	465,926.272	4,959,187.728	4.65	3.62	10	4.90E-05

Appendix K. 40 CFR Part 60, Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

§ 60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

(i) On or after July 1, 2008; or

(ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

(5) Owners and operators of stationary SI ICE that are modified or reconstructed after June 12, 2006, and any person that modifies or reconstructs any stationary SI ICE after June 12, 2006.

(6) The provisions of § 60.4236 of this subpart are applicable to all owners and operators of stationary SI ICE that commence construction after June 12, 2006.

(b) The provisions of this subpart are not applicable to stationary SI ICE being tested at an engine test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(d) For the purposes of this subpart, stationary SI ICE using alcohol-based fuels are considered gasoline engines.

(e) Stationary SI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR parts 1048 and 1054, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(f) Owners and operators of facilities with internal combustion engines that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

Emission Standards for Manufacturers

§ 60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008 to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, as follows:

If engine displacement is . . .	**and manufacturing dates are . . .**	**the engine must meet the following non-handheld emission standards identified in 40 CFR part 1054 and related requirements:**
(1) Below 225 cc	July 1, 2008 to December 31, 2011	Phase 2.
(2) Below 225 cc	January 1, 2012 or later	Phase 3.
(3) At or above 225 cc	July 1, 2008 to December 31, 2010	Phase 2.
(4) At or above 225 cc	January 1, 2011 or later	Phase 3.

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, for new nonroad SI engines in 40 CFR part 1054. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards and other requirements as appropriate for new nonroad SI engines in 40 CFR part 1054. For stationary SI ICE with a

maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

(e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048 applicable to engines that are not severe duty engines.

(f) Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, to the extent they apply to equipment manufacturers.

(g) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary SI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed stationary SI ICE.

§ 60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

Engines manufactured by stationary SI internal combustion engine manufacturers must meet the emission standards as required in § 60.4231 during the certified emissions life of the engines.

Emission Standards for Owners and Operators

§ 60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(a) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, must comply with the emission standards in § 60.4231(a) for their stationary SI ICE.

(b) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that use gasoline must comply with the emission standards in § 60.4231(b) for their stationary SI ICE.

(c) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in § 60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in § 60.4231(c) for their stationary SI ICE.

(d) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in Table 1 to this subpart for their emergency stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) manufactured prior to January 1, 2011, that were certified to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP, may optionally choose to meet those standards.

(e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

(f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.

(1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with emission standards in § 60.4231(a) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in § 60.4231(a) applicable to engines manufactured on July 1, 2008.

(2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline engines and are modified or reconstructed after June 12, 2006, must comply with the emission standards in § 60.4231(b) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in § 60.4231(b) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in § 60.4231(c). Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in § 60.4231(c) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006,

must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO_X) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of 1.0 g/HP-hr, or a NO_X emission standard of 250 ppmvd at 15 percent oxygen (O_2), a CO emission standard 540 ppmvd at 15 percent O_2 (675 ppmvd at 15 percent O_2 for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O_2, where the date of manufacture of the engine is:

(i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP (except lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;

(iii) Prior to January 1, 2009, for emergency engines;

(iv) Prior to January 1, 2008, for non-emergency lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP.

(5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines. Engines with maximum engine power less than 500 HP and a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power less than 500 HP manufactured on July 1, 2008. Engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) and a date of manufacture prior to July 1, 2007 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) manufactured on July 1, 2007. Lean burn engines greater than or equal to 500 HP and less than 1,350 HP with a date of manufacture prior to January 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE that are lean burn engines greater than or equal to 500 HP and less than 1,350 HP and manufactured on January 1, 2008.

(g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.

(h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

§ 60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in § 60.4233 over the entire life of the engine.

Other Requirements for Owners and Operators

§ 60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

Owners and operators of stationary SI ICE subject to this subpart that use gasoline must use gasoline that meets the per gallon sulfur limit in 40 CFR 1090.205.

§ 60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?

(a) After July 1, 2010, owners and operators may not install stationary SI ICE with a maximum engine power of less than 500 HP that do not meet the applicable requirements in § 60.4233.

(b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in § 60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in § 60.4233 may not be installed after January 1, 2010.

(c) For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in § 60.4233 after January 1, 2011.

(d) In addition to the requirements specified in §§ 60.4231 and 60.4233, it is prohibited to import stationary SI ICE less than or equal to 19 KW (25 HP), stationary rich burn LPG SI ICE, and stationary gasoline SI ICE that do not meet the applicable requirements specified in paragraphs (a), (b), and (c) of this section, after the date specified in paragraph (a), (b), and (c) of this section.

(e) The requirements of this section do not apply to owners and operators of stationary SI ICE that have been modified or reconstructed, and they do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

(a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(b) Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(c) If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

Compliance Requirements for Manufacturers

§ 60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines ≤19 KW (25 HP) or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(a) must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

§ 60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

§ 60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in § 60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and

other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

§ 60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?

(a) Manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable, under the voluntary certification program described in this subpart. Manufacturers who certify their engines under the voluntary certification program must meet the requirements as specified in paragraphs (b) through (g) of this section. In addition, manufacturers of stationary SI internal combustion engines who choose to certify their engines under the voluntary certification program, must also meet the requirements as specified in § 60.4247. Manufacturers of stationary SI internal combustion engines who choose not to certify their engines under this section must notify the ultimate purchaser that testing requirements apply as described in § 60.4243(b)(2); manufacturers must keep a copy of this notification for five years after shipping each engine and make those documents available to EPA upon request.

(b) Manufacturers of engines other than those certified to standards in 40 CFR part 1054 must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must follow the same test procedures that apply to Large SI nonroad engines under 40 CFR part 1048, but must use the D-1 cycle of International Organization for Standardization 8178-4: 1996(E) (incorporated by reference, see § 60.17) or the test cycle requirements specified in Table 3 to 40 CFR 1048.505, except that Table 3 of 40 CFR 1048.505 applies to high load engines only. Manufacturers of any size may certify their stationary emergency engines at or above 130 hp using assigned deterioration factors established by EPA, consistent with 40 CFR 1048.240. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1054, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR part 1054, appendix I, applicable to class II engines, must certify their stationary SI ICE using the certification and testing procedures required in 40 CFR part 1054, subparts C and F. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

(c) Certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, is voluntary, but manufacturers who decide to certify are subject to all of the requirements indicated in this subpart with regard to the engines included in their certification. Manufacturers must clearly label their stationary SI engines as certified or non-certified engines.

(d) Manufacturers of natural gas fired stationary SI ICE who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the definition of pipeline-quality natural gas. The fuel used for certifying stationary SI natural gas engines must meet the definition of pipeline-quality natural gas as described in § 60.4248. In addition, the manufacturer must provide information to the owner and operator of the certified stationary SI engine including the specifications of the pipeline-quality natural gas to which the engine is certified and what adjustments the owner or operator must make to the engine when installed in the field to ensure compliance with the emission standards.

(e) Manufacturers of stationary SI ICE that are lean burn engines fueled by LPG who conduct voluntary certification of stationary SI ICE to the emission standards specified in § 60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the specifications in 40 CFR 1065.720.

(f) Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in § 60.4231(d) or (e), as applicable, when operating on that fuel. The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition. The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on gaseous fuels with different quality than the fuel that it was certified to.

(g) A stationary SI engine manufacturer may certify an engine family solely to the standards applicable to landfill/digester gas engines as specified in § 60.4231(d) or (e), as applicable, but must certify their engines for operation using landfill/digester gas and must add a permanent label stating that the engine is for use only in landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

(i) For engines being certified to the voluntary certification standards in Table 1 of this subpart, the VOC measurement shall be made by following the procedures in 40 CFR part 1065, subpart C, to determine the total NMHC emissions. As an alternative, manufacturers may measure ethane, as well as methane, for excluding such levels from the total VOC measurement.

§ 60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR parts 1048, 1054, and 1068, as applicable, except that engines certified pursuant to the voluntary certification procedures in § 60.4241 are subject only to the provisions indicated in § 60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of § 60.4241(c) through (f). Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must

meet the provisions of 40 CFR part 1060, as applicable. Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.

(b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards identified in 40 CFR part 1048 or 1054 for that model year may certify any such family that contains both nonroad and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts. This paragraph (b) also applies to equipment or component manufacturers certifying to standards under 40 CFR part 1060.

(c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words “and stationary” after the word “nonroad” to the label.

(d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled and exported according to 40 CFR 1068.230. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.

(f) For manufacturers of gaseous-fueled stationary engines required to meet the warranty provisions in 40 CFR 1054.120, we may establish an hour-based warranty period equal to at least the certified emissions life of the engines (in engine operating hours) if we determine that these engines are likely to operate for a number of hours greater than the applicable useful life within 24 months. We will not approve an alternate warranty under this paragraph (f) for nonroad engines. An alternate warranty period approved under this paragraph (f) will be the specified number of engine operating hours or two years, whichever comes first. The engine manufacturer shall request this alternate warranty period in its application for certification or in an earlier submission. We may approve an alternate warranty period for an engine family subject to the following conditions:

(1) The engines must be equipped with non-resettable hour meters.

(2) The engines must be designed to operate for a number of hours substantially greater than the applicable certified emissions life.

(3) The emission-related warranty for the engines may not be shorter than any published warranty offered by the manufacturer without charge for the engines. Similarly, the emission-related warranty for any component shall not be shorter than any published warranty offered by the manufacturer without charge for that component.

Compliance Requirements for Owners and Operators

§ 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in § 60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in § 60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if you are an owner or operator.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in § 60.4233(d) or (e) and according to the requirements specified in § 60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in § 60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in § 60.4233(f).

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3), is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3), the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for the purpose specified in paragraph (d)(2)(i) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) [reserved]

(iii) [reserved]

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of § 60.4233.

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine undergoes rebuild, major repair or maintenance. Engine rebuilding means to overhaul an engine or to otherwise perform extensive service on the engine (or on a portion of the engine or engine system). For the purpose of this paragraph (f), perform extensive service means to disassemble the engine (or portion of the engine or engine system), inspect and/or replace many of the parts, and reassemble the

engine (or portion of the engine or engine system) in such a manner that significantly increases the service life of the resultant engine.

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

(h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.

(1) Purchasing an engine certified according to 40 CFR part 1048. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(i) If you are an owner or operator of a modified or reconstructed stationary SI internal combustion engine and must comply with the emission standards specified in § 60.4233(f), you must demonstrate compliance according to one of the methods specified in paragraphs (i)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in § 60.4233(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in § 60.4244. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

Testing Requirements for Owners and Operators

§ 60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in § 60.8 and under the specific conditions that are specified by Table 2 to this subpart.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in § 60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(c) You must conduct three separate test runs for each performance test required in this section, as specified in § 60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(d) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP - hr} \qquad \text{(Eq. 1)}$$

Where:

ER = Emission rate of NO_X in g/HP-hr.

C_d = Measured NO_X concentration in parts per million by volume (ppmv).

1.912×10^{-3} = Conversion constant for ppm NO_X to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP - hr} \qquad \text{(Eq. 2)}$$

Where:

ER = Emission rate of CO in g/HP-hr.

C_d = Measured CO concentration in ppmv.

1.164×10^{-3} = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP - hr} \qquad \text{(Eq. 3)}$$

Where:

ER = Emission rate of VOC in g/HP-hr.

C_d = VOC concentration measured as propane in ppmv.

1.833×10^{-3} = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \qquad \text{(Eq. 4)}$$

Where:

RF_i = Response factor of compound i when measured with EPA Method 25A.

C_{Mi} = Measured concentration of compound i in ppmv as carbon.

C_{Ai} = True concentration of compound i in ppmv as carbon.

$$C_{icorr} = RF_i \times C_{imeas} \qquad \text{(Eq. 5)}$$

Where:

C_{icorr} = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

C_{imeas} = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{eq} = 0.6098 \times C_{icorr} \qquad \text{(Eq. 6)}$$

Where:

C_{Peq} = Concentration of compound i in mg of propane equivalent per DSCM.

Notification, Reports, and Records for Owners and Operators

§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to § 60.4243(a)(2), documentation that the engine meets the emission standards.

(b) For all stationary SI emergency ICE greater than or equal to 500 HP manufactured on or after July 1, 2010, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in § 60.4231 must submit an initial notification as required in § 60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.

(1) Name and address of the owner or operator;

(2) The address of the affected source;

(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(4) Emission control equipment; and

(5) Fuel used.

(d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in § 60.4244 within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference - see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7.

(e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates for the purpose specified in § 60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) [reserved]

(vi) [reserved]

(vii) Hours spent for operation for the purposes specified in § 60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

General Provisions

§ 60.4246 What parts of the General Provisions apply to me?

(a) Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

(b) The provisions of 40 CFR 1068.10 and 1068.11 apply fror engine manufacturerers. For others the general confidential business information (CBI) provisions apply as described in 40 CFR part 2.

Mobile Source Provisions

§ 60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Manufacturers certifying to emission standards in 40 CFR part 1054 must meet the provisions of 40 CFR part 1054. Note that 40 CFR part 1054, appendix I, describes various provisions that do not apply for engines meeting Phase 1 standards in 40 CFR part 1054. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060 to the extent they apply to equipment manufacturers.

(b) Manufacturers required to certify to emission standards in 40 CFR part 1048 must meet the provisions of 40 CFR part 1048. Manufacturers certifying to emission standards in 40 CFR part 1048 pursuant to the voluntary certification program must meet the requirements in Table 4 to this subpart as well as the standards in 40 CFR 1048.101.

(c) For manufacturers of stationary SI internal combustion engines participating in the voluntary certification program and certifying engines to Table 1 to this subpart, Table 4 to this subpart shows which parts of the mobile source provisions in 40 CFR parts 1048, 1065, and 1068 apply to you. Compliance with the deterioration factor provisions under 40 CFR 1048.205(n) and 1048.240 will be required for engines built new on and after January 1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.

Definitions

§ 60.4248 What definitions apply to this subpart?

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

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 1054.107 and 1060.101, as appropriate. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a maximum engine power greater than 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first. You may request in your application for certification that we approve a shorter certified emissions life for an engine family. We may approve a shorter certified emissions life, in hours of engine operation but not in years, if we determine that these engines will rarely operate longer than the shorter certified emissions life. If engines identical to those in the engine family have already been produced and are in use, your demonstration must include documentation from such in-use engines. In other cases, your demonstration must include an engineering analysis of information equivalent to such

in-use data, such as data from research engines or similar engine models that are already in production. Your demonstration must also include any overhaul interval that you recommend, any mechanical warranty that you offer for the engine or its components, and any relevant customer design specifications. Your demonstration may include any other relevant information. The certified emissions life value may not be shorter than any of the following:

(1) 1,000 hours of operation.

(2) Your recommended overhaul interval.

(3) Your mechanical warranty for the engine.

Certified stationary internal combustion engine means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 1048 or 1054, as appropriate.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide (CO_2).

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency

stationary ICE must comply with the requirements specified in § 60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4243(d).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4243(d)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

Manufacturer has the meaning given in section 216(1) of the Clean Air Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1048.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar

year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Pipeline-quality natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to June 12, 2006, with passive emission control technology for NO_X (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to either: a gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Stationary internal combustion engine test cell/stand means an engine test cell/stand, as defined in 40 CFR part 63, subpart PPPPP, that tests stationary ICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Subpart means 40 CFR part 60, subpart JJJJ.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in § 60.4231(d) or (e), as applicable.

Table 1 to Subpart JJJJ of Part 60 - NO_X, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC[d]	NO_X	CO	VOC[d]
Non-Emergency SI Natural Gas[b] and Non-Emergency SI Lean Burn LPG[b]	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60
Non-Emergency SI Lean Burn Natural Gas and LPG	500≤HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≤HP<1,350)	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≤HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_X	CO	VOC[d]	NO_X	CO	VOC[d]
Emergency	25<HP<130	1/1/2009	[c] 10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

[a] Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O_2.

[b] Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

[c] The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_X + HC.

[d] For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

Table 2 to Subpart JJJJ of Part 60 - Requirements for Performance Tests

As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244	a. Limit the concentration of NO_X in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) [a d]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR part 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for NO_X concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03 [d e]	(d) Measurements to determine moisture must be made at the same time as the measurement for NO_X concentration.
		v. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 7E of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (Reapproved 2005),[a d] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03 [d e]	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of CO in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for CO, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification

For each	Complying with the requirement to	You must	Using	According to the following requirements
				testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) [a d]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for CO concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03 [d e]	(d) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.
		v. Measure CO at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM Method D6522-00 (Reapproved 2005),[a d e] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03 [d e]	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	c. Limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for VOC, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (`3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-

For each	Complying with the requirement to	You must	Using	According to the following requirements
				diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at `3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) [a d]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for VOC concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03 [d e]	(d) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.
		v. Measure VOC at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Methods 25A and 18 of 40 CFR part 60, appendices A-6 and A-7, Method 25A with the use of a hydrocarbon cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A-6,[c e] Method 320 of 40 CFR part 63, appendix A,[e] or ASTM Method D6348-03 [d e]	(e) Results of this test consist of the average of the three 1-hour or longer runs.

[a] Also, you may petition the Administrator for approval to use alternative methods for portable analyzer.

[b] You may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

[c] You may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (*http://www.epa.gov/ttn/emc/prelim/otm11.pdf*).

[d] Incorporated by reference; see 40 CFR 60.17.

[e] You must meet the requirements in § 60.4245(d).

Table 3 to Subpart JJJJ of Part 60 - Applicability of General Provisions to Subpart JJJJ

[As stated in § 60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.4248.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and Recordkeeping	Yes	Except that § 60.7 only applies as specified in § 60.4245.
§ 60.8	Performance tests	Yes	Except that § 60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§ 60.9	Availability of information	Yes	
§ 60.10	State Authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	No	
§ 60.14	Modification	Yes	
§ 60.15	Reconstruction	Yes	
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device requirements	No	

General provisions citation	Subject of citation	Applies to subpart	Explanation
§ 60.19	General notification and reporting requirements	Yes	

Table 4 to Subpart JJJJ of Part 60 - Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ

[As stated in § 60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	
1048 subpart B	Emission Standards and Related Requirements	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No	
1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	
1048.140	Certifying Blue Sky Series Engines	No	
1048.145	Interim Provisions	No	
1048 subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes	
1048.205(p)(2)	Liquid Fuels as they require	No	
1048.240(b)(c)(d)	Deterioration Factors	Yes	
1048 subpart D	Testing Production-Line Engines	Yes	

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart E	Testing In-Use Engines	No	
1048 subpart F	Test Procedures	Yes	
1065.5(a)(4)	Raw sampling (refers reader back to the specific emissions regulation for guidance)	Yes	
1048 subpart G	Compliance Provisions	Yes	
1048 subpart H	Reserved		
1048 subpart I	Definitions and Other Reference Information	Yes	
1048 appendix I and II	Yes		
1065 (all subparts)	Engine Testing Procedures	Yes	Except for the specific section below.
1065.715	Test Fuel Specifications for Natural Gas	No	
1068 (all subparts)	General Compliance Provisions for Nonroad Programs	Yes	Except for the specific sections below.
1068.245	Hardship Provisions for Unusual Circumstances	No	
1068.250	Hardship Provisions for Small-Volume Manufacturers	No	
1068.255	Hardship Provisions for Equipment Manufacturers and Secondary Engine Manufacturers	No	

Technical Support Document
For
Air Emission Permit No. 13900010-105

This technical support document (TSD) is intended for all parties interested in the permit and to meet the requirements that have been set forth by the federal and state regulations (40 CFR § 70.7(a)(5) and Minn. R. 7007.0850, subp. 1). The purpose of this document is to provide the legal and factual justification for each applicable requirement or policy decision considered in the determination to issue the permit.

1. General information

1.1 Applicant and stationary source location:

Table 1. Applicant and source address

Applicant/Address	**Stationary source/Address** (SIC Code: 4911 - Electric Services)
Xcel Energy 414 Nicollet Mall Minneapolis, Minnesota 55401-1927	Xcel Energy - Blue Lake 1200 70th St S Shakopee, MN 55379-2100
Contact: Hannah Mathers Phone: 763-647-4338	

1.2 Facility description

The Xcel Energy (Permittee) Blue Lake Generating Plant (facility) is an electric generation peaking plant composed of six simple cycle stationary combustion turbine (CT) generators. Four of the CTs were manufactured by Turbodyne and installed in the 1970s. Three are rated at 50 Megawatts (MWe) each, and one is rated at 55 MWe. They are all fired with distillate fuel oil No. 2.

Two General Electric CTs rated at 174 MWe each and fired with natural gas were installed at the facility in 2004 and are equipped with dry low-NOx combustors to inhibit NOx formation. The Permittee also operates an emergency generator.

The main pollutants are products of combustion such as nitrogen oxides (NOx), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC), particulate matter (PM), particulate matter less than ten microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), hazardous air pollutants (HAPs), and greenhouse gases (GHG or CO_2e).

1.3 Description of the activities allowed by this permit action

This permit action is a major amendment and will add three engine generators rated at 9.37 Megawatts (MWe) each, five emergency generators, three rated at 750 kilowatts (kW) and two rated at 550 kW, two 100,000 gallon diesel storage tanks and a paved roads fugitive source. The amendment will also revise limits on the existing natural gas fired turbines to ensure availability during peak demand and decommission the four oil fired turbines at the facility. Oxygen continuous emissions monitors will be added for the two natural gas fired turbines and selective catalytic reduction and oxidation catalyst controls will be added for the three engine generators. Parametric monitors will be added to monitor temperature and pressure drop on the control equipment.

The MPCA has a combined operating and construction permitting program under Minn. R. ch. 7007. Under that authority, this permit action authorizes construction.

1.4 Description of notifications and applications included in this action

Table 2. Notifications and applications included in this action

Date received	Application/notification type and description
11/03/2023	Major Amendment (IND20220001)

1.5 Facility emissions:

Table 3. Title I emissions summary

Pollutant	Emissions increase from the modification (tpy)	Limited emissions increase from the modification (tpy)	Source-wide contemporaneous increases and decreases* (tpy)	Net emissions increase (tpy)	NSR/112(g) Significant thresholds for major sources (tpy)	NSR/ 112(g) review required? (yes/no)
PM	181.23	16.23	0.00	16.23	25	Yes****
PM_{10}	181.28	26.29	0.00	26.29	15	Yes
$PM_{2.5}$	181.28	40.29	0.00	40.29	10	Yes
NO_x	862.51	-16,240	0.00	-16,240	40	Yes***
SO_2	11.82	-43.81	0.00	-43.81	40	No
CO	459.30	245	0.00	245	100	Yes
Ozone (VOC)	212.42	169.74	0.00	169.74	40	Yes
Lead	0.00	0.00	0.00	0.0	0.6	No
CO_2e**	2,192,404	-1,626,090	0.00	-1,626,090	75,000	Yes***
total HAPs	23.9	0.00	0.00	0.00	10/25	No

*Other emission changes during the contemporaneous period as defined by 40 CFR § 52.21, 40 CFR § 52.24 or 40 CFR pt. 51.
**Carbon dioxide equivalents as defined in Minn. R. 7007.0100.
*** NOx, CO_2e increase from new equipment is in column 2. Reductions in column 3 include reductions from removed existing turbines (EQUI 1-4)
**** PM increase from new and modified equipment is in column 2.

Table 4. Total facility potential to emit summary

	PM tpy	PM_{10} tpy	$PM_{2.5}$ tpy	SO_2 tpy	NO_x tpy	CO Tpy	CO_2e tpy	VOC tpy	Single HAP tpy	All HAPs tpy
Total Facility Limited Potential Emissions (post mod)	181	181	181	12	864	379	2,192,449	213	9.0	22.5

Table 5. Facility classification

Classification	Major	Synthetic minor/area	Minor/area
PSD	X		
Part 70 Permit Program	X		
Part 63 NESHAP		X	

1.6 Changes to permit

In addition to the changes to the permit listed in Section 1.3, the following changes to the permit are also made through this permit action.

- The permit has been updated to reflect current Minnesota Pollution Control Agency (MPCA) templates and standard citation formatting;
- All standard language has been updated to reflect current guidance;
- Parametric monitors (EQUI 17-20) were removed as these were duplicates of the NOx and CO emissions monitors for the natural gas turbines (EQUI 7, 8);
- Limits to avoid major modification in COMG 2 for EQUIs 7 and 8 were removed. A revised BACT analysis for EQUIs 7 and 8 is included with this permit amendment and proposes new BACT limits to replace the limits to avoid major modification;
- The first three requirements of COMG 4 of permit 13900010-104 were removed as EQUIs 7 and 8 are no longer eligible for Part 75 Appendix E or low mass emissions (LME) method in 40 CFR 75.19 and must have NOx CEMS. Additional requirements at EQUIs 7 and 8 related to Part 75 Appendix E and LME method were removed from the permit.
- The basis for CEMS was updated, NOx and O_2 CEMS basis is Part 75, CO CEMS basis is Part 60;
- Appendices G: 40 CFR Part 60 Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, H: Fugitive Dust Control Plan, I: General Public Preclusion Plan, J: Modeling Parameters and K: 40 CFR Part 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines have been added to the permit.

2. Regulatory and/or statutory basis

2.1 New source review (NSR)

The facility is an existing major source under New Source Review regulations. The permit does not change this status but does authorize a major modification under New Source Review as documented in Table 3 and Attachments 1 and 3 of this TSD.

2.2 Part 70 permit program

The facility is a major source under the Part 70 permit program.

2.3 New source performance standards (NSPS)

The Permittee has stated that New Source Performance Standards apply to the operations at this facility. 40 CFR pt. 60, subp. IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines applies to EQUIs 23-25 (Engine Generators 1-3) and EQUIs 26-29, and 43 (Emergency Engines 2-6). 40 CFR pt 60, subp. JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines applies to EQUIs 23-25 (Engine Generators 1-3).

2.4 National emission standards for hazardous air pollutants (NESHAP)

The facility has accepted limits on HAP emissions such that it is an area source under 40 CFR pt. 63. Thus, no major source NESHAPs apply. However, the area source NESHAP 40 CFR pt. 63, subp. ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines applies to EQUIs 23-25 (Engine Generators 1-3) and EQUIs 26-29, and 43 (Emergency Engines 2-6).

EQUIs 23-29 are each new affected sources as defined under 40 CFR pt. 63, subp. ZZZZ, located at an area source of HAPs per 40 CFR 63.6590(c). The Permittee will meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII.

2.5 Acid rain program

Xcel Energy - Blue Lake is subject to the Acid Rain Program of 40 CFR pts. 72, 73, and 75. MPCA implements the Acid Rain Program based on direction from EPA.

The combustion turbines (EQUI 7 and EQUI 8) are subject to nitrogen oxides and sulfur dioxides Acid Rain requirements. As such, the Permittee is required to measure nitrogen oxides emissions and measure or calculate sulfur dioxide emissions. The Permittee is also required to maintain records of these emissions. The Acid Rain Permit Application is included as Appendix B of the permit.

EQUIs 1-4 are not subject to the Acid Raid Program because they were installed in 1974 which is before the 1990 compliance date.

2.6 Cross State Air Pollution Rule (CSAPR)

Xcel Energy - Blue Lake is subject to CSAPR (also known as the Transport Rule (TR)) because it has 4 distillate fuel-fired combustion turbines (EQUIs 1-4) and 2 natural gas-fired combustion turbines (EQUI 7 & 8) that serve, on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe producing electricity for sale. Specifically, the facility is subject to the requirements of the TR NOx Annual Program (40 CFR pt. 97, subp. AAAAA) and the TR SO_2 Group 2 Trading Program (40 CFR pt. 97, subp. DDDDD) because Minnesota is subject to the TR NOx Annual Trading Program pursuant to 40 CFR 52.38(a)(2) and Minnesota is subject to the requirements of the TR SO_2 Group 2 Trading Program pursuant to 40 CFR 52.39(c). This replaces CAIR, to which the facility was previously subject.

2.7 Environmental Justice

The Minnesota Pollution Control Agency's (MPCA) mission is to protect and improve our environment and enhance human health, and the agency is committed to ensuring that pollution does not have a disproportionate impact on any group of people. The MPCA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The impacts of pollution vary across Minnesota, and historical inequities have exposed some populations such as people of color, low-income households, and people with underlying health issues to greater health impacts from pollution.

Permits are an important tool used to protect the environment and people in Minnesota. The permitting process is a critical opportunity to identify activities and pollutants that pose the greatest risk to neighborhoods of environmental concern, and to evaluate potential pollution reduction efforts. Permit actions also allow for community involvement in an accessible and meaningful manner. This will allow the MPCA and the facilities to understand and address community concerns and establish or enhance relationships with the surrounding community members.

Xcel Energy - Blue Lake is located at 1200 70th St S, Shakopee, MN 55379. This is an environmental justice area because 40% or more of the population are people of color and is located near an area where at least 35% of the population report income less than 200% of the federal poverty level. The facility is also located near federally recognized tribal land.

2.8 Compliance assurance monitoring (CAM)

The table below lists the sources subject to CAM, the control equipment used, whether the source is a large or other pollutant specific emission unit (PSEU), and the pollutants triggering CAM.

Table 6. CAM summary

Unit	Control	CAM applicability	Pollutant	Emission Limitation Basis
EQUI 23	TREA 1, 2 oxidation catalyst & SCR	Other	CO, NOx	BACT & PSD modeling
EQUI 24	TREA 3, 4 oxidation catalyst & SCR	Other	CO, NOx	BACT & PSD modeling

Unit	Control	CAM applicability	Pollutant	Emission Limitation Basis
EQUI 25	TREA 5, 6 oxidation catalyst & SCR	Other	CO, NOx	BACT & PSD modeling

Since the EQUI qualify as Other PSEU, a CAM plan is not required until the next Title V reissuance.

2.9 Environmental review and air emissions risk analysis (AERA)

The facility has accepted a limit on carbon monoxide in COMG 2 such that it is not subject to environmental review, i.e., an Environmental Assessment Worksheet (EAW), and is not required to perform an Air Emissions Risk Analysis (AERA). The facility also accounted for emissions reductions from the decommissioning of EQUIs 1-4 to avoid an EAW.

2.10 Regulatory overview

Table 7. Regulatory overview of units affected by the modification/permit amendment

Subject item*	Applicable regulations	Rationale
COMG 2 (NG-Fired GE 7FA Combustion Turbines)	Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)	Limit to avoid Environmental Assessment Worksheet (EAW): Carbon monoxide limit to keep emissions increase below 250 tons.
COMG 5 (HAPs Limits)	Title I Condition: Avoid major source under 40 CFR 63.2	NESHAPs: Limits carried forward on individual and total HAPs to avoid major source classification under 40 CFR 63.2. Limits will incorporate engine generators (EQUIs 23-25) and emergency generators (EQUIs 26-29) into the existing limits.
EQUIs 7-8 (NG Combustion Turbines)	Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000	Prevention of Significant Deterioration: PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOC, CO_2, CO_2e and fuel type BACT limits
	Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000	Prevention of Significant Deterioration Modeling: $PM_{2.5}$ and NOx modeling limits
EQUIs 23-25 (Engine Generators 1-3)	Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000	Prevention of Significant Deterioration: PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOC, CO_2, CO_2e and fuel type BACT limits
	Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000	Prevention of Significant Deterioration Modeling: $PM_{2.5}$ and NOx modeling limits
	40 CFR pt. 60, subp. IIII, Minn. R. 7011.2305	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines • Manufactured after April 1, 2006; • Non-emergency stationary CI engine with displacement greater than or equal to 30 liters per cylinder; • Engine installed on or after January 1, 2016.
	40 CFR pt 60, subp. JJJJ, Minn. R. 7011.2310	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines • Constructed after June 12, 2006; • Installed after July 1, 2009.

Subject item*	Applicable regulations	Rationale
	40 CFR pt. 63, subp. ZZZZ, Minn. R. 7011.8150	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines • The facility is an area source of HAP emissions; • New stationary RICE; • Meets requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subps. IIII and JJJJ.
	Minn. R. 7011.2300	Standards of Performance for Stationary Internal Combustion Engines: SO_2 and opacity limits
	Minn. R. 7007.0800, subp. 11	Alternative Operating Scenarios for operation in dual fuel and diesel modes.
EQUIs 26-29, 43 (Emergency Generators 2-6)	Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000	Prevention of Significant Deterioration: PM, PM_{10}, $PM_{2.5}$, CO, VOC, NMHC+NOx, opacity, fuel type, and CO_2e BACT limits
	40 CFR pt. 60, subp. IIII, Minn. R. 7011.2305	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines • Emergency engine; • 2007 and later model year; • Less than 30 liters per cylinder displacement; • Output >750 and $\leq$3,000 hp.
	40 CFR pt. 63, subp. ZZZZ, Minn. R. 7011.8150	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines • The facility is an area source of HAP emissions; • New emergency stationary RICE; • Meets requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII.
	Minn. R. 7011.2300	Standards of Performance for Stationary Internal Combustion Engines: SO_2 and opacity limits
EQUIs 32-33 (Diesel Storage Tanks)	Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000	Prevention of Significant Deterioration: Good tank design for storage tanks.
TREAs 1, 3, 5 (Oxidation Catalysts)	Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000	Prevention of Significant Deterioration: CO, VOC control efficiencies, pressure drop and temperature inlet/outlet BACT limits.
TREAs 2, 4, 6 (SCR)	Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000	Prevention of Significant Deterioration: NOx control efficiency, pressure drop and temperature inlet/outlet BACT limits.
FUGI 1 (paved roads)	Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000	Prevention of Significant Deterioration: Comply with requirements, actions and recordkeeping specified in the Fugitive Dust Control Plan (Appendix H).

*Location of the requirement in the permit (e.g., EQUI 1, STRU 2, etc.).

3. Technical information

3.1 Calculations of potential to emit and emissions increase analysis

Attachment 1 to this TSD contains a summary of the PTE of the Facility as well as detailed spreadsheets and supporting information prepared by the MPCA and the Permittee.

Oil-fired turbines (EQUI 1-4) are to be decommissioned at the facility, but their PTE are included in this permit action. Criteria pollutant emission factors are taken from AP-42 Tables 3.1-1 and 3.1-2a for uncontrolled distillate oil-fired turbines. NOx emission factors are from stack test results and SO_2 uses the 15 ppm standard for sulfur content in distillate fuel. CO_2e is calculated using the CO_2, CH_4 and N_2O emission factors from AP-42 Table 3.1-2a and applying the global warming potentials (GWP) of each pollutant.

The existing diesel-fired emergency engine (EQUI 5) uses emission factors from AP-42 Table 3.3-1 for uncontrolled diesel industrial engines. PM and $PM_{2.5}$ emissions are assumed equal to PM_{10} emissions. Emission factors for CH_4 and N_2O are taken from 40 CFR pt. 98 Table C-1 for petroleum products. CO_2e is calculated by applying GWP for each greenhouse gas (GHG) pollutant.

The natural gas-fired turbines (EQUI 7, 8) use emission factors from AP-42 Table 3.1-2a for PM, CO_2 and CH_4. PM_{10} and $PM_{2.5}$ emissions are assumed equal to PM. The SO_2 emission factor is taken from AP-42 Table 1.4-2 which is for an external combustion boiler, but is representative of natural gas with only sulfur due to added mercaptan. The VOC emission factor is a calculated lb/hr value from BACT ppm concentration and annual values include startup and shutdown. CO and NOx emission factors are based on worst-case performance tests with annual values including startup and shutdown. The N_2O emission factor is from 40 CFR pt. 98 Table C-1 for natural gas. CO_2e is again calculated by applying GWP for each GHG pollutant.

EQUI 7 and 8 include BACT limits for startup and shutdown operations as these units are unable to comply with normal operation BACT limits upon startup and shutdown. Startup and shutdown BACT limits are typically less stringent than normal operating BACT limits. For the natural gas turbines, Xcel Energy proposes 200 startup and shutdown events per year based on data collected from a turbine at the Xcel Energy Black Dog facility that is the same type. The duration of startup (23 minutes) and shutdown (11 minutes) times are based on manufacturer data.

The three new engine generators (EQUI 23-25) take their emission factors from BACT engine specifications with annual values including startup and shutdown (for diesel fuel). The natural gas emission factors do not include annual values including startup and shutdown as diesel will be used as a pilot fuel for startup. These BACT engine specification emission factors are for criteria pollutants CO, NOx, PM_{10}, $PM_{2.5}$, and VOC (see Attachment 5). The PM emission factor is assumed equal to PM_{10}. The CO_2 emission factor is from BACT engine specifications (Attachment 5) and SO_2 emission factor is taken from AP-42 Table 3.4-1 for large stationary diesel and dual-fuel engines. 15 ppm is assumed for diesel fuel and 6 ppm is assumed for natural gas and a 95%/5% natural gas/diesel mix. CH_4 and N_2O emission factors are taken from 40 CFR pt. 98 Table C-2 for petroleum products. CO_2e is calculated by applying GWP for each GHG pollutant.

Like the natural gas turbines, the engine generators also contain startup and shutdown BACT limits and 700 events per year are proposed. This number of events per year is based on predicted future use of the units. The duration of startup (30 minutes) and shutdown (1 minute) times are based on manufacturer data. Both the natural gas turbines and engine generators are allotted 48 hours per year of emergency operation. This amount of hours per year is based on one black start per year where the units would be providing power to get the facility and grid back online.

The five new emergency generators (EQUI 26-29, 43) take their CO, NOx, PM, PM_{10} and $PM_{2.5}$ emission factors from 40 CFR pt. 60, subp. IIII. The PM_{10} emission factor assumes filterable PM with condensable PM. $PM_{2.5}$ is assumed equal to PM_{10}. The emission factors for SO_2, VOC and CO_2 are taken from AP-42 Table 3.4-1 for large stationary diesel engines. CH_4 and N_2O emission factors are taken from 40 CFR pt. 98 Table C-2 for petroleum products. CO_2e is calculated by applying GWP for each GHG pollutant.

Emissions calculations for the diesel storage tanks (EQUI 32-33) are from AP-42 chapter 7. Each tank has a fixed roof and stores 100,000 gallons of diesel fuel. The maximum true vapor pressure is 0.01 psia.

3.2 Dispersion modeling

Xcel Energy - Blue Lake conducted a Significant Impact Level (SIL) analysis for all modeled criteria pollutants to determine which pollutants would need to conduct refined modeling. SILs are defined concentrations of criteria pollutants in the ambient air that are considered inconsequential in comparison to the National Ambient Air Quality Standards (NAAQS). The screening analysis for PM_{10}, CO and ozone demonstrate that they are below the SIL. The screening analysis identified that emissions exceed the SIL for NO_2 and $PM_{2.5}$. Therefore, refined modeling is required to demonstrate that impacts would not exceed the NAAQS.

Table 8. Significant Impact Level Analysis for CO, NO_2, Ozone, PM_{10} and $PM_{2.5}$

Pollutant & Avg Period	SIL (ug/m³)	Maximum Modeled Concentration (ug/m³)	Percent of SIL (%)
PM_{10} 24-hour	5	4.6	92%
PM_{10} Annual	1	0.32	32%
NO_2 1-hour	7.5	27.2	363%
NO_2 Annual	1	0.86	86%
CO 1-hour	2000	13	1%
CO 8-hour	500	8	2%
$PM_{2.5}$ 24-hour	1.2	3.3	275%
$PM_{2.5}$ Annual	0.13	0.28	215%
	SIL (ppb)	**Maximum Modeled Concentration (ppb)**	
Ozone 8-hour	1	0.22	22%

Xcel Energy - Blue Lake proceeded with NAAQS modeling for $PM_{2.5}$ and NO_2 following the results of the SIL screening analysis. Nearby sources for NO_2 NAAQS modeling included Blue Lake WWTP and Anchor Glass. The NO_2 background monitor used was the Lakeville, MN I-35 roadside monitor. Nearby sources for $PM_{2.5}$ NAAQS modeling included Anchor Glass and CertainTeed Corp. The $PM_{2.5}$ background monitor used was the Shakopee, MN monitor. The NAAQS modeling results are shown below in Table 9.

Table 9. NAAQS Modeling Results

Pollutant	Avg. Period	NAAQS standard (ug/m³)	Modeled Results plus Background (ug/m³)	Percent of NAAQS standard (%)
$PM_{2.5}$	24-hr	35	30.4	87%
$PM_{2.5}$	Annual	9	8.1	90%
NO_2	1-hour	188	95.8	51%

Class II increment modeling was conducted for $PM_{2.5}$. There was no Class II increment modeling for NO_2 as there is no Class II increment standard for NO_2. The increment modeling represents actual emissions increases and decreases of all sources at the facilities since a denoted minor source baseline date. Xcel Energy - Blue Lake is located in Scott County which has a minor source baseline date of 2014. Actual baseline emissions are represented from emissions inventories from two years prior (2012-2013) compared to the most recent two years of actual emissions (2020-2021). The $PM_{2.5}$ increment model included Xcel Energy - Blue Lake post-project, Rahr Malting, Anchor Glass, CertainTeed Corp, and Koda Energy. The Class II increment modeling results are shown below in Table 10.

Nearby source modeling inputs for CertainTeed included an underestimation of 0.08 lb/hr $PM_{2.5}$ emissions or 0.35 tpy. As shown above in Table 9, Xcel Energy - Blue Lake modeled 90% of the $PM_{2.5}$ annual NAAQS and 87% of the 24-hr NAAQS standard. Given the minor discrepancies in $PM_{2.5}$ emissions modeled for CertainTeed, and the amount of room remaining below the standards, it is unlikely that adding the 0.08 lb/hr would have a significant impact on the results that were modeled for this facility. The $PM_{2.5}$ annual NAAQS standard has been revised to 9 ug/m³ and annual SIL has been revised to 0.13 ug/m³.

Table 10. Class II Increment Modeling Results

Pollutant	Avg. Period	Class II Increment (ug/m^3)	Total modeled conc. (includes other increment sources) (ug/m^3)	Percent of Increment standard (%)
$PM_{2.5}$	24-hr	9	3.7	41%
$PM_{2.5}$	Annual	4	0.4	10%

The worst-case emission rates for NOx and $PM_{2.5}$ have been incorporated as permit limits in the permit and cited with PSD modeling citations. In addition, per MPCA practice, a table of the modeled parameters has been added to the permit as an appendix. The parameters listed in Appendix J of the permit describe the operation of the facility at maximum capacity. In other words, the flow rates and temperatures listed in Appendix J represent the minimum parameters at the maximum emission rates. The MPCA does not require any specific compliance demonstration with these parameters because they are worst case conditions. The purpose of listing the parameters in the permit appendix is to provide a benchmark for determining if and when additional modeling is required.

Engine Generators 1-3 (EQUIs 23-25) are limited to 2 startup/shutdown events per day. Worst case emissions are when each unit starts up on diesel and operates under normal operation using diesel.

Table 11. Short Term PM10/PM2.5 PTE Calculation for Modeling

Engine Generator 1-3 operation	Wartsila lb/hr	SUSD lb/event	Duration hours	SUSD events/day	PM lb/day	lb/hr w/ SU lb/hr	lb/hr that would be used in modeling
2 diesel SUSD + normal operation on diesel	4.53	5.00	0.5	2	114.19	4.76	4.76
24 hours normal operation on diesel	4.53	NA	NA	NA	108.72	NA	4.53
24 hours of SUSD on PNG (pipeline natural gas)	NA	2.034	0.52	46.45	94.48	3.94	3.94
2 PNG SUSD + normal operation on PNG	2.01	2.030	0.52	2	50.22	2.09	2.09
24 hours normal operation on PNG	2.01	2.026	NA	NA	48.24	NA	2.01
2 diesel SUSD + all other periods PNG SUSD	NA	2.022 2.018	0.50 0.52	2 44.23	99.97	4.17	4.17

MPCA Air Modeling staff recalculated the secondary contributions from NOx and SO_2 for the project and saw minimal changes in the reported values. The changes typically involved +/- 0.02 ug/m^3 and did not affect the compliance status of the modeling report. Although with the change in the Annual $PM_{2.5}$ NAAQS itself, the facility would be at 90% of the standard instead of the 68% reported in their final modeling report submittal. The 90% of the NAAQS standard is listed above in Table 9.

3.3 Ambient air boundary

In the air dispersion modeling analysis, the Permittee omitted receptors on portions of the facility property. These portions of the atmosphere accessible on the facility property must be excluded from ambient air. The Permittee maintains security fencing along the entire facility perimeter and a controlled access gate. This fence line defines the ambient air boundary used for siting receptors in the air dispersion modeling

analysis. The MPCA has determined that the existing security fencing is sufficient to establish an ambient air boundary, based on guidance contained in the 1980 letter from the US Environmental Protection Agency (EPA) Administrator Douglas Costle to Senator Jennings Randolph and the March 28, 2017 MPCA Memorandum "Clarification of MPCA Working Practice to Evaluate the Federal Definition of Ambient Air in Air Quality Dispersion Modeling."" (Appendix D to MPCA Air Dispersion Modeling Practices Manual). This determination is also consistent with the US EPA November 2018 Draft "Revised Policy On Exclusions from 'Ambient Air'." This permit requires the Permittee to comply with a general public preclusion plan, which must be maintained onsite. The Permittee must document any security breaches, as well as identify any security deficiencies and update the Plan accordingly to prevent future breaches. Appendix I to the permit includes a map depicting the ambient air boundary defined by the fence line.

3.4 NSR/PSD Construction Authorization under 40 CFR 52.21(r)(2)

Xcel Energy - Blue Lake will be authorized to construct EQUIs 23-29 and TREAs 1-6 upon issuance of this permit. Construction authorization shall expire if construction does not commence within 18 months after issuance of this permit. Construction authorization can also expire if construction is discontinued for a period of 18 months or more or if construction is not completed within a reasonable time.

3.5 BACT Summary

This permit action removes existing synthetic minor limits on EQUI 7 and EQUI 8 (combustion turbines) to allow increased utilization resulting in increases of CO, NOx, PM, PM_{10}, $PM_{2.5}$, VOC and GHG emissions. The addition of three 9.37 MW Wartsila dual fuel engine generators (EQUIs 23-25) which can combust ultra-low sulfur diesel and natural gas and four diesel emergency engines (EQUIs 26-29). All of these emission units are subject to BACT.

Combustion Turbines BACT (EQUIs 7, 8)

Three technologies were identified in the BACT analysis for particulate control of the combustion turbines: clean fuels, good combustion practices and add-on particulate controls. Of these, clean fuels and good combustion practices were considered technically feasible. Use of add-on controls like baghouse, electrostatic precipitator or wet scrubber can provide particulate control for solid and liquid fuel combustion applications, though add-on control technologies are not technically feasible for natural gas combustion due to capture limitations and low particulate concentration levels.

Good combustion practices and use of natural gas as a clean fuel are selected as BACT for controlling particulate emissions from EQUIs 7 and 8.

Nine technologies were identified in the BACT analysis for NOx control. Four of these technologies were deemed not technically feasible: SNCR (selective non-catalytic reduction), XONON, EM_X (formerly $SCONO_X$) and NSCR (non-selective catalytic reduction). Control technologies that were deemed technically feasible were SCR (selective catalytic reduction), dry low NOx burners, water injection, clean fuels and good combustion practices. SCR was eliminated as it was deemed not economically feasible with a cost per ton in the range of $27,400 to $34,300 per ton of NOx removed.

BACT selection for NOx control are use of dry low NOx burners which are inherent to the combustion turbines, clean fuels, and good combustion practices. Water injection with dry low NOx burners on similar turbines showed no demonstration of lower NOx emissions that from using dry low NOx burners alone.

Four technologies were identified in the BACT analysis for CO and VOC control of EQUIs 7 and 8. Two of them were deemed not technically feasible: SCONOx and NSCR. Oxidation catalyst was deemed economically infeasible with CO cost effectiveness of $10,519 per ton removed and VOC cost effectiveness of $26,837 per ton removed. However, when two pollutants are controlled by an add-on control device, a multipollutant cost effectiveness threshold (MCET) can be calculated. For Xcel's combustion turbine BACT analysis, the MCET is calculated below:

MCET = (196.28 ton CO uncontrolled - 9.81 ton CO controlled) x ($3,301) + (76.93 ton VOC uncontrolled - 3.85 ton VOC controlled) x ($10,000) = $1,346,337

In the BACT analysis, Xcel calculates a total annual cost of $1,961,366 for the add-on control. Since the total annual cost is greater than the calculated MCET, the add-on control is shown to be not economically feasible.

This left good combustion practices as the selected BACT for CO and VOC.

Dual Fuel Engines BACT (EQUIs 23-25)

Seven technologies were identified in the BACT analysis for particulate control of the dual fuel engines, of which emergency use classification and diesel particulate filter were deemed technically infeasible. The remaining five technologies were selected as BACT for particulate control: primary use of pipeline natural gas with ultra-low sulfur diesel as an option, compliance with 40 CFR pt. 60, subp. IIII limits and requirements, good combustion practices and an oxidation catalyst.

Diesel particulate filters (DPF) were deemed not technically feasible for the proposed Wartsila engines. Wartsila has no installed DPF references. In 2010 a Wartsila diesel engine was tested with diesel oxidation catalyst (DOC) and particle oxidation catalyst (POC) for PM removal in combination with SCR. The engine operated on palm oil. The measured PM removal with DOC & POC was 70%. However, the engine operated with such a high backpressure in excess of its normal limits, the engine was derating due to the high backpressure. DPF is expensive and requires frequent regeneration (fuel) or mechanical cleaning which impacts operation cost and plant availability. To date, Wartsila has not identified a supplier of DPF technology that meets their customer demands. See Attachment 6.

Six technologies were identified in the BACT analysis for NOx control. SNCR and NSCR were deemed technically infeasible. NOx BACT selection included the use of SCR, use of pipeline natural gas with ultra-low sulfur diesel as an option, and good combustion practices.

Four technologies were identified in the BACT analysis for CO and VOC control of the dual fuel engines. Only NSCR was deemed technically infeasible. The remaining technologies were selected as BACT. Those included SCR, use of pipeline natural gas with ultra-low sulfur diesel as an option and good combustion practices.

Emergency Diesel Engine Generators BACT (EQUIs 26-29, 43)

Six technologies were identified in the BACT analysis for particulate control of the emergency diesel engine generators, of which DPF and oxidation catalyst were deemed technically infeasible. The four remaining technologies were selected as BACT. Those include emergency use classification, use of ultra-low sulfur diesel, purchasing a certified engine in accordance with NSPS subp. IIII requirements and good combustion practices.

Seven technologies were identified for NOx emissions control. The three technologies deemed not technically feasible were SNCR, NSCR and SCR. The remaining four technologies were selected as BACT for the emergency engines. These technologies include emergency use classification, use of ultra-low sulfur diesel, purchasing a certified engine in accordance with NSPS subp. IIII requirements and good combustion practices.

Five technologies were identified for CO and VOC emissions control. Two technologies deemed not technically feasible were oxidation catalyst and NSCR. The three remaining technologies were selected as BACT. Those technologies include emergency use classification, purchasing a certified engine in accordance with NSPS subp. IIII requirements and good combustion practices.

GHG BACT

The BACT analysis identified three emission control technologies available for GHG. Carbon capture, utilization and sequestration or storage (CCUS), use of clean fuels and good combustion practices and energy efficient measures. CCUS was comprised of carbon capture, carbon transport and storage, and carbon utilization. The cost of CCUS was deemed economically infeasible. Thus, clean fuels and good combustion practices were selected as GHG BACT for this project.

For GHG leaks, the facility will utilize proper piping design conforming to ANSI, API, ASME or other standards and best management practices to prevent, detect, and repair leaks of natural gas.

Diesel Tank BACT (EQUIs 32, 33)

Two diesel fuel storage tanks will be constructed and operated with good tank design, including: fixed roof, PRV (conservation vent), submerged fill pipe, and light tank color.

Fuel Deliveries Paved Road BACT (FUGI 1)
The paved roads for fuel deliveries (FUGI 1) at the facility will comply with the fugitive emission control plan located in Appendix H.

For a detailed discussion of the BACT analysis for this project, see Attachment 3.

3.6 Monitoring

In accordance with the Clean Air Act, it is the responsibility of the owner or operator of a facility to have sufficient knowledge of the facility to certify that the facility is in compliance with all applicable requirements.

In evaluating the monitoring included in the permit, the MPCA considered the following:

- The likelihood of the facility violating the applicable requirements.
- Whether add-on controls are necessary to meet the emission limits.
- The variability of emissions over time.
- The type of monitoring, process, maintenance, or control equipment data already available for the emission unit.
- The technical and economic feasibility of possible periodic monitoring methods.
- The kind of monitoring found on similar units elsewhere.

The table below summarizes the monitoring requirements associated with this amendment.

Table 12. Monitoring

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
COMG 2 (NG-Fired GE 7FA Combustion Turbines)	Carbon Monoxide <= 310.8 tons per year 12-month rolling sum (Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B))	Recordkeeping: Daily and monthly calculations of CO emissions from EQUI 7, 8	Through calculations using fuel usage data and an AP-42 emission factor, compliance with the CO emission limit can be readily and directly determined. The Permittee must use a CO CEMS to show compliance with the limit.
COMG 5 (HAPs Limits)	HAPs - Total <= 22.5 tons per year 12-month rolling sum HAPs - Single <= 9.0 tons per year 12-month rolling sum (Title I Condition: avoid major source under 40 CFR 63.2)	Recordkeeping: Daily and monthly records of fuel usage. Monthly recording of HAPs Total emissions for the previous calendar month, as well as total HAPs Total emissions for the previous 12-month period.	Records of fuel usage are generated on a daily basis. HAPs emissions are calculated using fuel usage records and emission factors. By recording the fuel usage on a daily basis, the Permittee is able to verify compliance status at any time. EQUI 5 and insignificant activities (IAs) HAP emissions are not tracked because the single and total HAP emissions from EQUI 5 and IAs are well below the (1.0 tpy/2.5 tpy) difference between the single/total HAP major source thresholds and the permit single/total HAP limits.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
EQUI 7, 8 (NG Combustion Turbines)	Nitrogen Oxides <= 11 parts per million (dry basis) corrected to 15% O_2 24-hr rolling avg Nitrogen Oxides <= 73.51 lb/hr 24-hr rolling avg normal operation (modeled) Nitrogen Oxides <= 6.76 tons per year 12-month rolling sum SU/SD Nitrogen Oxides <= 7.29 tons per year 12-month rolling sum emergency operation Carbon Monoxide <= 9 parts per million (dry basis) corrected to 15% O_2 24-hr rolling avg Carbon Monoxide <= 38.80 lb/hr 24-hr rolling avg normal operation Carbon Monoxide <= 18.01 tons per year 12-month rolling sum SU/SD Carbon Monoxide <= 11.47 tons per year 12-month rolling sum emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	NOx & CO CEMS operation and maintenance Recordkeeping for SU/SD, emergency operation	NOx CEMS (EQUIs 9, 11) are used to measure NOx emissions continuously; therefore, the CEMS will provide continuous assurance of compliance. CO CEMS (EQUIs 10, 12) are used to measure CO emissions continuously; therefore, the CEMS will provide continuous assurance of compliance. Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 200 events per year. Emergency operation limited to 48 hours per year.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Particulate Matter <= 0.0066 lb/mmBtu heat input 3-hr rolling avg Particulate Matter <= 13.48 lb/hr 3-hr avg (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after permit issuance.
	PM < 10 micron <= 0.0066 lb/mmBtu heat input 3-hr rolling avg PM < 10 micron <= 13.48 lb/hr 3-hr avg PM < 2.5 micron <= 0.0066 lb/mmBtu heat input 3-hr rolling avg PM < 2.5 micron <= 13.48 lb/hr 3-hr avg (modeled) (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after permit issuance.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Volatile Organic Compounds <= 4.6 parts per million (dry basis) at actual O_2 (as methane) 3-hr block avg Volatile Organic Compounds <= 10.03 lb/hr 3-hr avg (as methane) normal operation Volatile Organic Compounds <= 8.64 tons per year 12-month rolling sum (as methane) SU/SD Volatile Organic Compounds <= 24.95 tons per year 12-month rolling sum (as methane) emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test Recordkeeping for SU/SD, emergency operation	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after permit issuance. Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 200 events per year. Emergency operation limited to 48 hours per year.
	Carbon Dioxide <= 110 lb/mmBtu heat input 3-hr rolling avg Carbon Dioxide Equivalent <= 986,539 tons per year 12-month rolling sum (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Recordkeeping: Monthly records of fuel burned (in mmBtu) and monthly calculations to calculate 12-month rolling sum of CO_2e emissions	The Permittee is able to use records of fuel burned (in mmBtu) to calculate monthly and 12-month rolling sum CO_2e emissions. 12-month rolling sum is adequate to ensure the CO_2e emissions stay below the BACT limit.
	Fuel use: Pipeline natural gas (Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000)	Monthly records of fuel type and usage, fuel supplier certification	Fuel supplier certifications for each fuel purchase should comply with the SO_2 limit of 0.0015 lb/mmBtu.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
EQUIs 23-25 (Engine Generators 1-3)	Operating Hours <= 241 hr/yr burn-in operation 12-mo rolling sum Operating Hours <= 8109 hr/yr normal operation 12-mo rolling sum (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Daily/Monthly Recordkeeping of hours of operation	Daily and monthly recordkeeping of the hours of operation of the units is sufficient to show compliance with the hours of operation in burn-in and normal operation of the units. These limits expire 366 days after initial startup of EQUIs 23-25.
	Nitrogen Oxides <= 6.7 * n^-0.20 g/hp-hr @ 130 ≤ n < 2000 rpm AOS2 (40 CFR 60.4204 (c)(3)(ii), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150)	Performance test See additional monitoring for NOx at TREAs 2, 4 & 6 Recordkeeping for AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. EQUIs 23-25 are new affected sources as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. Record the AOS each day of operation. Record the date and time of change to new AOS.
	Nitrogen Oxides <= 1.0 g/hp-hr or 82 ppmvd @ 15% O_2 AOS1 Carbon Monoxide <= 2.0 g/hp-hr or 270 ppmvd @ 15% O_2 AOS1 Volatile Organic Compounds <= 0.7 g/hp-hr or 60 ppmvd @ 15% O_2 AOS1 (40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150)	Performance test See additional monitoring for NOx at TREAs 2, 4 & 6 Recordkeeping for AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. EQUIs 23-25 are new affected sources as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. JJJJ. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Nitrogen Oxides <= 0.07 g/hp-hr 24-hr rolling avg AOS1 & >= 75% load Nitrogen Oxides <= 0.39 g/hp-hr 24-hr rolling avg AOS2 & >= 75% load Nitrogen Oxides <= 0.11 g/hp-hr 24-hr rolling avg AOS1 & < 75% load Nitrogen Oxides <= 0.49 g/hp-hr 24-hr rolling avg AOS2 & < 75% load Nitrogen Oxides <= 1.65 lb/hr 3-hr avg AOS1 normal operation Nitrogen Oxides <= 10.86 lb/hr 3-hr avg AOS2 normal operation (modeled) (Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000) Nitrogen Oxides <= 15.82 tons per year 12-month rolling sum SU/SD Nitrogen Oxides <= 2.16 tons per year 12-month rolling sum emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test See additional monitoring for NOx at TREAs 2, 4 & 6 Recordkeeping for SU/SD, emergency operation, AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. All normal operation limits (excluding SU/SD and emergency operation) apply after 241 hours of burn-in operation or upon commencement of normal operation of EQUIs 23-25, whichever comes first. Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 700 events per year. Emergency operation limited to 48 hours per year. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Particulate Matter <= 0.11 g/hp-hr 24-hr rolling avg or reduce PM by >= 60% at >= 75% load (40 CFR 60.4204 (c)(4), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000) Particulate Matter <= 2.01 lb/hr 3-hr avg AOS1 normal operation Particulate Matter <= 4.76 lb/hr 3-hr avg AOS2 normal operation (Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000) Particulate Matter <= 1.77 tons per year 12-month rolling sum SU/SD Particulate Matter <= 0.24 tons per year 12-month rolling sum emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance Test Recordkeeping for SU/SD, emergency operation, AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. All normal operation limits (excluding SU/SD and emergency operation) apply after 241 hours of burn-in operation or upon commencement of normal operation of EQUIs 23-25, whichever comes first. Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 700 events per year. Emergency operation limited to 48 hours per year. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	PM < 10 micron <= 0.07 g/hp-hr 24-hr rolling avg AOS1 >= 75% load PM < 10 micron <= 0.16 g/hp-hr 24-hr rolling avg AOS2 >= 75% load PM < 10 micron <= 0.12 g/hp-hr 24-hr rolling avg AOS1 < 75% load PM < 10 micron <= 0.24 g/hp-hr 24-hr rolling avg AOS2 < 75% load PM < 10 micron <= 2.01 lb/hr 3-hr avg AOS1 normal operation PM < 10 micron <= 4.76 lb/hr 3-hr avg AOS2 normal operation (Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000) PM < 10 micron <= 1.77 tons per year 12-month rolling sum SU/SD PM < 10 micron <= 0.24 tons per year 12-month rolling sum emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test Recordkeeping for SU/SD, emergency operation, AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. All normal operation limits (excluding SU/SD and emergency operation) apply after 241 hours of burn-in operation or upon commencement of normal operation of EQUIs 23-25, whichever comes first. Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 700 events per year. Emergency operation limited to 48 hours per year. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	PM < 2.5 micron <= 0.07 g/hp-hr 24-hr rolling avg AOS1 >= 75% load PM < 2.5 micron <= 0.16 g/hp-hr 24-hr rolling avg AOS2 >= 75% load PM < 2.5 micron <= 0.12 g/hp-hr 24-hr rolling avg AOS1 < 75% load PM < 2.5 micron <= 0.24 g/hp-hr 24-hr rolling avg AOS2 < 75% load PM < 2.5 micron <= 2.01 lb/hr 3-hr avg AOS1 normal operation PM < 2.5 micron <= 4.76 lb/hr 3-hr avg AOS2 normal operation (modeled) (Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000) PM < 2.5 micron <= 1.77 tons per year 12-month rolling sum SU/SD PM < 2.5 micron <= 0.24 tons per year 12-month rolling sum emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test Recordkeeping for SU/SD, emergency operation, AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. All normal operation limits (excluding SU/SD and emergency operation) apply after 241 hours of burn-in operation or upon commencement of normal operation of EQUIs 23-25, whichever comes first. Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 700 events per year. Emergency operation limited to 48 hours per year. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Carbon Monoxide <= 0.10 g/hp-hr 24-hr rolling avg AOS1 >= 75% load Carbon Monoxide <= 0.14 g/hp-hr 24-hr rolling avg AOS2 >= 75% load Carbon Monoxide <= 0.11 g/hp-hr 24-hr rolling avg AOS1 < 75% load Carbon Monoxide <= 0.15 g/hp-hr 24-hr rolling avg AOS2 < 75% load Carbon Monoxide <= 2.51 lb/hr 3-hr avg AOS1 normal operation Carbon Monoxide <= 3.78 lb/hr 3-hr avg AOS2 normal operation (Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000) Carbon Monoxide <= 3.71 tons per year 12-month rolling sum SU/SD Carbon Monoxide <= 0.50 tons per year 12-month rolling sum emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test See additional monitoring for CO at TREAs 1, 3 & 5 Recordkeeping for SU/SD, emergency operation, AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. All normal operation limits (excluding SU/SD and emergency operation) apply after 241 hours of burn-in operation or upon commencement of normal operation of EQUIs 23-25, whichever comes first. Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 700 events per year. Emergency operation limited to 48 hours per year. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Volatile Organic Compounds <= 0.13 g/hp-hr 24-hr rolling avg (as methane) AOS1 >= 75% load Volatile Organic Compounds <= 0.15 g/hp-hr 24-hr rolling avg (as methane) AOS2 >= 75% load Volatile Organic Compounds <= 0.22 g/hp-hr 24-hr rolling avg (as methane) AOS1 < 75% load Volatile Organic Compounds <= 0.17 g/hp-hr 24-hr rolling avg (as methane) AOS2 < 75% load Volatile Organic Compounds <= 3.26 lb/hr 3-hr avg (as methane) AOS1 normal operation Volatile Organic Compounds <= 4.33 lb/hr 3-hr avg (as methane) AOS2 normal operation (Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Performance test See additional monitoring for VOC at TREAs 1, 3 & 5 Recordkeeping for AOS	Testing frequencies are typically set at 12, 36, or 60-month increments. Past test results, applicable rules, potential emissions, location of source, and past compliance history play a factor in setting the testing frequency. This permit requires initial performance test due 180 days after initial startup. All normal operation limits apply after 241 hours of burn-in operation or upon commencement of normal operation of EQUIs 23-25, whichever comes first. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Volatile Organic Compounds <= 1.16 tons per year 12-month rolling sum (as methane) SU/SD Volatile Organic Compounds <= 0.15 tons per year 12-month rolling sum emergency operation (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Recordkeeping for SU/SD, emergency operation	Monthly recordkeeping of startup/shutdown events and emergency operation. SU/SD limited to 700 events per year. Emergency operation limited to 48 hours per year.
	Sulfur Content of Fuel <= 1000 parts per million per gallon AOS2 (40 CFR 60.4207 (d), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150)	Fuel type certification and fuel monitoring Recordkeeping for AOS	It is not anticipated that the engine generators (EQUIs 23-25) would violate the limit, based on allowable fuel. Record the AOS each day of operation. Record the date and time of change to new AOS.
	Carbon Dioxide <= 377 g/hp-hr 24-hr rolling avg AOS1 Carbon Dioxide <= 494 g/hp-hr 24-hr rolling avg AOS2 (Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000) Carbon Dioxide Equivalent <= 72,583 tons per year 12-month rolling sum (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Recordkeeping: Monthly records of fuel burned (in mmBtu) and monthly calculations to calculate 12-month rolling sum of CO_2e emissions Recordkeeping for AOS	The Permittee is able to use records of fuel burned (in mmBtu) to calculate monthly and 12-month rolling sum CO_2e emissions. 12-month rolling sum is adequate to ensure the CO_2e emissions stay below the BACT limit. Record the AOS each day of operation. Record the date and time of change to new AOS.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	Sulfur Dioxide <= 0.0015 lb/mmBtu heat input Opacity <= 20% (Minn. R. 7011.2300, subps. 1 & 2(B))	Monthly recordkeeping of the type and amount of fuel used	The engine generators (EQUIs 23-25) use natural gas and diesel only; therefore, the likelihood of violating either of the limits is very small. Design based PTE, using AP-42 is 0.0015 lb/mmBtu of SO_2 compared to the rule limit.
	Fuel use: Natural gas & diesel only (Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000)	Monthly records of fuel type and usage, fuel supplier certification	Fuel supplier certifications for each fuel purchase should comply with the SO_2 limit of 0.0015 lb/mmBtu.
EQUIs 26-29, 43 (Emergency Generators 2-6)	NMHC+NOx <= 4.8 g/hp-hr 24-hr rolling avg Particulate Matter <= 0.15 g/hp-hr 24-hr rolling avg Carbon Monoxide <= 2.6 g/hp-hr 24-hr rolling avg Opacity <= 20% in acceleration mode Opacity <= 15% in lugging mode Opacity <= 50% in peaks of either acceleration or lugging modes (40 CFR 60.4202 (a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Purchase certified engine, operation according to mfr's emissions related instructions, records of maintenance	Monitoring required by the NSPS is adequate to demonstrate compliance with the requirements because this standard was promulgated after November 15, 1990, and post-November 15, 1990, NSPS and NESHAPs contain adequate monitoring. EQUIs 26-29, 43 are new affected sources as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
	PM < 10 micron <= 0.16 g/hp-hr 24-hr rolling avg PM < 2.5 micron <= 0.16 g/hp-hr 24-hr rolling avg Volatile Organic Compounds <= 4.8 g/hp-hr 24-hr rolling avg (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Purchase certified engine, operation according to mfr's emissions related instructions, records of maintenance	Monitoring required by the NSPS is adequate to demonstrate compliance with the requirements because this standard was promulgated after November 15, 1990, and post-November 15, 1990, NSPS and NESHAPs contain adequate monitoring. EQUIs 26-29, 43 are new affected sources as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII.
	Sulfur Dioxide <= 0.0015 lb/mmBtu heat input Opacity <= 20% (Minn. R. 7011.2300, subps. 1 & 2(B))	Monthly recordkeeping of the type and amount of fuel used	The emergency generators (EQUIs 26-29) use diesel only; therefore, the likelihood of violating either of the limits is very small. Design based PTE, using AP-42 is 0.0015 lb/mmBtu of SO_2 compared to the rule limit.
	Fuel type: diesel only, by design (Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) & Minn. R. 7007.3000)	Monthly records of fuel type and usage, fuel supplier certification	Fuel supplier certifications for each fuel purchase should comply with the SO_2 limit of 0.0015 lb/mmBtu.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
EQUIs 26-28 (Emergency Generators 2-4)	NMHC+NOx <= 11.03 lb/hr 3-hr avg Particulate Matter <= 0.35 lb/hr 3-hr avg PM < 10 micron <= 0.39 lb/hr 3-hr avg PM < 2.5 micron <= 0.39 lb/hr 3-hr avg Carbon Monoxide <= 6.03 lb/hr 3-hr avg Volatile Organic Compounds <= 11.03 lb/hr 3-hr avg (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Purchase certified engine, operation according to mfr's emissions related instructions, records of maintenance	Monitoring required by the NSPS is adequate to demonstrate compliance with the requirements because this standard was promulgated after November 15, 1990, and post-November 15, 1990, NSPS and NESHAPs contain adequate monitoring.
	Carbon Dioxide Equivalent <= 314 tons per year 12-month rolling sum (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Recordkeeping: Monthly records of fuel burned (in mmBtu) and monthly calculations to calculate 12-month rolling sum of CO_2e emissions	The Permittee is able to use records of fuel burned (in mmBtu) to calculate monthly and 12-month rolling sum CO_2e emissions. 12-month rolling sum is adequate to ensure the CO_2e emissions stay below the BACT limit.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
EQUIs 29, 43 (Emergency Generators 5-6)	NMHC+NOx <= 8.12 lb/hr 3-hr avg Particulate Matter <= 0.25 lb/hr 3-hr avg PM < 10 micron <= 0.29 lb/hr 3-hr avg PM < 2.5 micron <= 0.29 lb/hr 3-hr avg Carbon Monoxide <= 4.44 lb/hr 3-hr avg Volatile Organic Compounds <= 8.12 lb/hr 3-hr avg (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Purchase certified engine, operation according to mfr's emissions related instructions, records of maintenance	Monitoring required by the NSPS is adequate to demonstrate compliance with the requirements because this standard was promulgated after November 15, 1990, and post-November 15, 1990, NSPS and NESHAPs contain adequate monitoring.
	Carbon Dioxide Equivalent <= 231 tons per year 12-month rolling sum (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Recordkeeping: Monthly records of fuel burned (in mmBtu) and monthly calculations to calculate 12-month rolling sum of CO_2e emissions	The Permittee is able to use records of fuel burned (in mmBtu) to calculate monthly and 12-month rolling sum CO_2e emissions. 12-month rolling sum is adequate to ensure the CO_2e emissions stay below the BACT limit.
EQUIs 32-33 (Diesel Storage Tanks)	Fixed roof, pressure relief valve, submerged fill pipe, light tank color (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	None	Each 100,000 gallon diesel storage tank shall be constructed with a fixed roof, pressure relief valve (conservation vent), a submerged fill pipe and have a light tank color.
FUGI 1 (Paved Roads)	Comply with Fugitive Emission Control Plan in Appendix H (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000	Daily visible emission checks, monitoring, recordkeeping, training, corrective actions	The Permittee shall follow the procedures outlined in the fugitive emission control plan to ensure compliance with Minn. R. 7011.0150 and the contents of the control plan. The fugitive emission control plan is contained in Appendix H of the permit.

Subject item*	Requirement (rule basis)	What is the monitoring	Why is this monitoring adequate?
TREA 1, 3, 5 (Oxidation Catalyst)	Carbon Monoxide >= 90 percent control efficiency Volatile Organic Compounds >= 90 percent control efficiency ΔP <= +/- 2.0 inches water Temperature >= 484 & <= 1350 degrees F (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000	Daily and periodic inspections, pressure drop, inlet/outlet temp monitoring, operation and maintenance, corrective actions	Monitoring based on the Minnesota Performance Standard for Control Equipment and pending CAM plan (due at next reissuance) provides a reasonable assurance of compliance.
TREA 2, 4, 6 (SCR)	Nitrogen Oxides >= 90 percent control efficiency ΔP <= +/- 2.0 inches water Temperature >= 484 & <= 1350 degrees F (Title I Condition: 40 CFR 52.21(j) (BACT) & Minn. R. 7007.3000)	Daily and periodic inspections, pressure drop, inlet/outlet temp monitoring, operation and maintenance, corrective actions	Monitoring based on the Minnesota Performance Standard for Control Equipment and pending CAM plan (due at next reissuance) provides a reasonable assurance of compliance.

*Location of the requirement in the permit (e.g., EQUI 1, STRU 2, etc.).

3.7 Insignificant activities

Xcel Energy - Blue Lake has several operations which are classified as insignificant activities under the MPCA's permitting rules. These are listed in Appendix A to the permit. There are no insignificant activities included in this modification.

3.8 Permit organization

This permit meets the MPCA Tempo Guidance for ordering and grouping of requirements as well as the use of permit appendices.

However, in this permit, federal requirements from NESHAPs and NSPS are included in two different formats. The requirements for 40 CFR pt. 60, subp. GG are incorporated into the permit as individual permit requirements, which has historically been MPCA's standard practice. However, the requirements for 40 CFR pt. 63, subp. ZZZZ and the associated General Provisions in 40 CFR pt. 63, subp. A, as well as the requirements for 40 CFR pt. 60, subps. IIII and JJJJ and the associated General Provisions in 40 CFR pt. 60, subp. A are included in a different way.

For these rules, limits and submittal/actions are included individually in the permit like the other standards. For the remaining portions of the rule, a requirement in Section 5 of the permit lists the citations of all of the applicable parts of the standard along with a reference to the permit appendix where the full text of the standard is included. 40 CFR pt. 63, subps. ZZZZ and A are included in Appendices E and D, respectively. 40 CFR pt. 60, subps. IIII, JJJJ and A are included in Appendices G, K and C, respectively.

3.9 Comments received

Public Notice Period: June 27, 2024 – July 29, 2024
EPA Review Period: June 27, 2024 – July 29, 2024

No comments were received during the public notice period and no changes were made to the draft permit. EPA Region 5 stated via email on July 26, 2024 that the draft permit was reviewed and they had no comments.

4. Permit fee assessment

Attachment 7 to this TSD contains the MPCA's assessment of Application and Additional Points used to determine the permit application fee for this permit action as required by Minn. R. 7002.0019. The permit action includes one permit application received after the effective date of the rule (July 1, 2009). The action includes limits to avoid Environmental Review, review of NSPS subps. IIII and JJJJ and NESHAP subp. ZZZZ, NAAQS and Class II increment modeling and a BACT analysis for the following pollutants: PM, PM_{10}, $PM_{2.5}$, NOx, CO, VOC and GHG.

5. Conclusion

Based on the information provided by Xcel Energy - Blue Lake the MPCA has reasonable assurance that the proposed operation of the emission facility, as described in the Air Emission Permit No. 13900010-105 and this TSD, will not cause or contribute to a violation of applicable federal regulations and Minnesota Rules.

Staff members on permit team:
Tarik Hanafy (permit engineer)
Jeffrey Hedman (peer reviewer)
Curt Stock/Ross Provow (performance testing)
Marin Morrell (enforcement)
Jimmy Schneider (modeling)
Owen Seltz/Jose Luis Villasenor/Ned Brooks (environmental justice)
Hannah Sabroski (communications)
Joe Handtmann (data coordinator)
Laurie O'Brien (administrative support)

Tempo Activities: Major Amendment (IND20220001)

Attachments:
1. PTE summary and emissions increase calculation spreadsheets
2. Subject item inventory and requirements report
3. BACT Analysis
4. Modeling Results
5. Manufacturer Guarantees
6. Wartsila Summary on Diesel Particulate Filter Technology
7. Points Calculator

Attachment 1 - PTE Summary and Emission Increase Calculation Spreadsheets

Xcel Energy
Blue Lake Conversion Project
Project Change Emission Summary
12/16/2022

Pollutant	Pre Modification Limited TPY
CO	134.1
NOx	17,106.5
PM	165.2
PM10	155.2
PM2.5	141.2
SO2	55.7
VOC	42.9
CO2	3,813,781
CH4	154
N2O	4
CO2e	3,818,803
Footnote:	[1]

Pollutant	Post Modification Controlled TPY	Post Modification Limited TPY [4]
CO	460	379
NOx	864	864
PM	181	181
PM10	181	181
PM2.5	181	181
SO2	12	12
VOC	213	213
CO2	2,186,837	2,186,837
CH4	161	161
N2O	5	5
CO2e	2,192,449	2,192,449
Footnote:	[2]	

Pollutant	Post Modification Project Change Controlled TPY	Post Modification Project Change Limited TPY [4]
CO	326	245
NOx	(16,243)	(16,243)
PM	16.16	16.16
PM10	26.21	26.21
PM2.5	40.21	40.21
SO2	(44)	(43.81)
VOC	169.60	169.60
CO2	(1,626,944)	(1,626,943.98)
CH4	6.97	6.97
N2O	1.39	1.39
CO2e	(1,626,354)	(1,626,354.00)

EAW Threshold TPY
250
250
250
250
250
250
250
NA [3]
NA [3]
NA [3]
100,000

Limited Emissions - Current Permit TPY
133.81
17105.38
165.08
155.08
155.08
55.63
42.83

[1] Pre-Modification includes Units 1-4 and 7-8. Permit limits used for limited PTE as applicable
[2] Post modification assuming Units 1-4 are decommissioned, PTE based on maximum throughput and do not account for permit limits
[3] The EAW threshold is expressed as "carbon dioxide equivalents" so there is no threshold in terms of individual greenhouse gases
[4] An annual CO emission limit is proposed for the natural gas fired turbines to keep the change below 250 tpy (see CD-01 form for COMG 2)

Table 3

SI IDs:	EQUI 7	EQUI 8	EQUI 23	EQUI 24	EQUI 25	EQUI 26	EQUI 27	EQUI 28	EQUI 29	EQUI 43	Total
Pollutant	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**	**PTE (tpy)**
PM	59.04	59.04	20.92	20.92	20.92	0.09	0.09	0.09	0.06	0.06	181.23
PM_{10}	59.04	59.04	20.92	20.92	20.92	0.10	0.10	0.10	0.07	0.07	181.28
$PM_{2.5}$	59.04	59.04	20.92	20.92	20.92	0.10	0.10	0.10	0.07	0.07	181.28
NO_x	330.10	330.10	63.32	63.32	63.32	2.76	2.76	2.76	2.03	2.03	862.51
SO_2	5.11	5.11	0.53	0.53	0.53	2.87E-03	2.87E-03	2.87E-03	2.12E-03	2.12E-03	11.82
CO	196.28	196.28	20.00	20.00	20.00	1.51	1.51	1.51	1.11	1.11	459.30
VOCs	76.73	76.73	19.40	19.40	19.40	0.17	0.17	0.17	0.13	0.13	212.42
Lead	-	-	-	-	-	-	-	-	-	-	0.00
Fluorides	-	-	-	-	-	-	-	-	-	-	0.00
Sulfuric acid mist	-	-	-	-	-	-	-	-	-	-	0.00
H_2S	-	-	-	-	-	-	-	-	-	-	0.00
Total reduced sulfur including H_2S	-	-	-	-	-	-	-	-	-	-	0.00
Total reduced sulfur compounds including H2S	-	-	-	-	-	-	-	-	-	-	0.00
MWC organics	-	-	-	-	-	-	-	-	-	-	0.00
MWC acid gas	-	-	-	-	-	-	-	-	-	-	0.00
MWC metals	-	-	-	-	-	-	-	-	-	-	0.00
MSW landfill gas	-	-	-	-	-	-	-	-	-	-	0.00
CO2e	986539	986539	72640	72640	72640	314	314	314	231	231	2192404

Table 4

Column A	Column B	Column C	Column D	Column E
Pollutant	**Sum from Table 2 (tpy)**	**Sum from Table 3 (tpy)**	**Total Sum of Differences (tpy)**	**Sig. Thresholds for major sources (tpy)**
PM	-	181.23	181.23	25.00
PM_{10}	-	181.28	181.28	15.00
$PM_{2.5}$	-	181.28	181.28	10.00
NO_x	-	862.51	862.51	40.00
SO_2	-	11.82	11.82	40.00
CO	-	459.30	459.30	100.00
VOCs	-	212.42	212.42	40.00
Lead	-	0.00	0.00	0.6
Fluorides	-	0.00	0.00	3
Sulfuric acid mist	-	0.00	0.00	7
H_2S	-	0.00	0.00	10
Total reduced sulfur including H_2S	-	0.00	0.00	10
Total reduced sulfur compounds including H2S	-	0.00	0.00	10
MWC organics	-	0.00	0.00	0.0000035
MWC acid gas	-	0.00	0.00	40
MWC metals	-	0.00	0.00	15
MSW landfill gas	-	0.00	0.00	50
CO2e	-	2192404	2192404	75000

Xcel Energy
Blue Lake Conversion Project
Criteria and Greenhouse Gas (GHG) Emissions

12/16/2022

2191000 | 2192172.95 | 1173

Emission Unit ID	Old Emission Unit ID	Stack ID	Old Stack ID	Unit Name	Fuel	Pollutant	Max Hourly Process Rate	Process Rate Units	Max Annual Utilization	Units	Emission Factor	Emission Factor Units	Emission Factor Source	Emission Rate (lb/hr)	Uncontrolled PTE (ton/yr)	Pollution Control Efficiency (%)	Worst Case Controlled PTE (lb/hr)	Worst Case Controlled PTE (ton/yr)	Limited PTE Existing Permit (ton/yr)
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	CO	648	mmBtu/hr	8760	Hours	3.30E-03	lb/mmBtu	AP-42 Table 3.1-1, Uncontrolled	2.14	9.37	0.00	2.14	9.37	9.37
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	NOx	648	mmBtu/hr	8760	Hours	1.29E+00	lb/mmBtu	Stack Test 6/26/07 weighted average	835.42	3659.13	0.00	835.42	3659.13	3659.13
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	PM	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	PM10	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	PM2.5	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	SO2	648	mmBtu/hr	8760	Hours	1.50E-03	lb/mmBtu	Current Permit, 15 ppm Sulfur	0.97	4.26	0.00	0.97	4.26	4.26
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	VOC	648	mmBtu/hr	8760	Hours	4.10E-04	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.27	1.16	0.00	0.27	1.16	1.16
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	CO2	648	mmBtu/hr	8760	Hours	1.57E+02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	101736.00	445604	0.00	101736.00	445604	445603.68
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	CH4	648	mmBtu/hr	8760	Hours	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	N2O	648	mmBtu/hr	8760	Hours	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	CO2e	648	mmBtu/hr	8760	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	445604	0.00	NA	445604	445603.68
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	CO	648	mmBtu/hr	8760	Hours	3.30E-03	lb/mmBtu	AP-42 Table 3.1-1, Uncontrolled	2.14	9.37	0.00	2.14	9.37	9.37
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	NOx	648	mmBtu/hr	8760	Hours	1.34E+00	lb/mmBtu	Stack test 6/26/07 weighted average 4 loads	865.69	3791.74	0.00	865.69	3791.74	3791.74
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	PM	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	PM10	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	PM2.5	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	SO2	648	mmBtu/hr	8760	Hours	1.50E-03	lb/mmBtu	Current Permit, 15 ppm Sulfur	0.97	4.26	0.00	0.97	4.26	4.26
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	VOC	648	mmBtu/hr	8760	Hours	4.10E-04	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.27	1.16	0.00	0.27	1.16	1.16
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	CO2	648	mmBtu/hr	8760	Hours	1.57E+02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	101736.00	445604	0.00	101736.00	445604	445603.68
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	CH4	648	mmBtu/hr	8760	Hours	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	N2O	648	mmBtu/hr	8760	Hours	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	CO2e	648	mmBtu/hr	8760	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	445604	0.00	NA	445604	445603.68
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	CO	648	mmBtu/hr	8760	Hours	3.30E-03	lb/mmBtu	AP-42 Table 3.1-1, Uncontrolled	2.14	9.37	0.00	2.14	9.37	9.37
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	NOx	648	mmBtu/hr	8760	Hours	1.60E+00	lb/mmBtu	Stack test 6/28/07 weighted average 4 loads	1035.37	4534.92	0.00	1035.37	4534.92	4534.92
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	PM	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-1, Uncontrolled	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	PM10	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	PM2.5	648	mmBtu/hr	8760	Hours	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	7.78	34.06	0.00	7.78	34.06	34.06
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	SO2	648	mmBtu/hr	8760	Hours	1.50E-03	lb/mmBtu	Current Permit, 15 ppm Sulfur	0.97	4.26	0.00	0.97	4.26	4.26
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	VOC	648	mmBtu/hr	8760	Hours	4.10E-04	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.27	1.16	0.00	0.27	1.16	1.16
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	CO2	648	mmBtu/hr	8760	Hours	1.57E+02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	101736.00	445604	0.00	101736.00	445604	445603.68
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	CH4	648	mmBtu/hr	8760	Hours	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	N2O	648	mmBtu/hr	8760	Hours	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	CO2e	648	mmBtu/hr	8760	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	445604	0.00	NA	445604	445603.68
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	CO	740	mmBtu/hr	8760	0.00	3.30E-03	lb/mmBtu	AP-42 Table 3.1-1, Uncontrolled	2.44	10.70	0.00	2.44	10.70	10.70
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	NOx	740	mmBtu/hr	8760	0.00	1.57E+00	lb/mmBtu	Stack test 11/18/99	1160.17	5081.52	0.00	1160.17	5081.52	5081.52
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	PM	740	mmBtu/hr	8760	0.00	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	8.88	38.89	0.00	8.88	38.89	38.89
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	PM10	740	mmBtu/hr	8760	0.00	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	8.88	38.89	0.00	8.88	38.89	38.89
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	PM2.5	740	mmBtu/hr	8760	0.00	1.20E-02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled PM Filterable	8.88	38.89	0.00	8.88	38.89	38.89
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	SO2	740	mmBtu/hr	8760	0.00	1.50E-03	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled, 15 ppm Sulfur	1.11	4.86	0.00	1.11	4.86	4.86
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	VOC	740	mmBtu/hr	8760	0	4.10E-04	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.30	1.33	0.00	0.30	1.33	1.33
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	CO2	740	mmBtu/hr	8760	0.00	1.57E+02	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	116180.00	508868	0.00	116180.00	508868	508868.40
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	CH4	740	mmBtu/hr	8760	0.00	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	N2O	740	mmBtu/hr	8760	0.00	0.00E+00	lb/mmBtu	AP-42 Table 3.1-2a, Uncontrolled	0.00	0.00	0.00	0.00	0.00	0.00
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	CO2e	740	mmBtu/hr	8760	0.00	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	508868	0.00	NA	508868	508868.40
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	CO	1.1	mmBtu/hr	500	0.00	9.50E-01	lb/mmBtu	AP-42 Table 3.3-1, Uncontrolled	1.05	0.26	0.00	1.05	0.26	0.26
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	NOx	1.1	mmBtu/hr	500	0.00	4.41E+00	lb/mmBtu	AP-42 Table 3.3-1, Uncontrolled	4.85	1.21	0.00	4.85	1.21	1.21
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	PM	1.1	mmBtu/hr	500	0.00	3.10E-01	lb/mmBtu	Assumed equal to PM10	0.34	0.09	0.00	0.34	0.09	0.09
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	PM10	1.1	mmBtu/hr	500	0.00	3.10E-01	lb/mmBtu	AP-42 Table 3.3-1, Uncontrolled	0.34	0.09	0.00	0.34	0.09	0.09
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	PM2.5	1.1	mmBtu/hr	500	0.00	3.10E-01	lb/mmBtu	Assumed equal to PM10	0.34	0.09	0.00	0.34	0.09	0.09
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	SO2	1.1	mmBtu/hr	500	0.00	2.90E-01	lb/mmBtu	AP-42 Table 3.3-1, Uncontrolled	0.32	0.08	0.00	0.32	0.08	0.08
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	VOC	1.1	mmBtu/hr	500	0.00	3.50E-01	lb/mmBtu	AP-42 Table 3.3-1, Uncontrolled TOC	0.39	0.10	0.00	0.39	0.10	0.10
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	CO2	1.1	mmBtu/hr	500	0.00	1.64E+02	lb/mmBtu	AP-42 Table 3.3-1, Uncontrolled	180.40	45.10	0.00	180.40	45.10	45.10
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	CH4	1.1	mmBtu/hr	500	0.00	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.01	1.82E-03	0.00	0.01	0.00	1.82E-03
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	N2O	1.1	mmBtu/hr	500	0.00	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.00	3.64E-04	0.00	0.00	0.00	3.64E-04
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	CO2e	1.1	mmBtu/hr	500	0.00	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	45	0.00	NA	45	45.25
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	CO	2042.4	mmBtu/hr	8760	Hours	3.88E+01	lb/hr	Worst-case based on performance testing; annual values include SU/SD	38.80	196.28	0.00	38.80	196.28	95
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	NOx	2042.4	mmBtu/hr	8760	Hours	7.35E+01	lb/hr	Worst-case based on performance testing; annual values include SU/SD	73.51	330.10	0.00	73.51	330.10	38.0
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	PM	2042.4	mmBtu/hr	8760	Hours	6.60E-03	lb/mmBtu	AP-42 Table 3.1-2a	13.48	59.04	0.00	13.48	59.04	24.0
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	PM10	2042.4	mmBtu/hr	8760	Hours	6.60E-03	lb/mmBtu	Assumed equal to PM	13.48	59.04	0.00	13.48	59.04	14.0
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	PM2.5	2042.4	mmBtu/hr	8760	Hours	6.60E-03	lb/mmBtu	Assumed equal to PM	13.48	59.04	0.00	13.48	59.04	NA
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	SO2	1.9	MMSCF/hr	8760	Hours	6.00E-01	lb/mmBtu	AP-42 Table 1.4-2 [3]	1.17	5.11	0.00	1.17	5.11	38.0
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	VOC	2042.4	mmBtu/hr	8760	Hours	1.00E+01	lb/hr	Calculated lb/hr from BACT ppm concentration; annual values include SU/SD	10.03	76.73	0.00	10.03	76.73	38.0
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	CO2	2042.4	mmBtu/hr	8760	Hours	1.10E+02	lb/mmBtu	AP-42 Table 3.1-2a	224,664	984,028	0.00	224,664	984,028	NA
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	CH4	2042.4	mmBtu/hr	8760	Hours	8.60E-03	lb/mmBtu	AP-42 Table 3.1-2a	17.56	76.93	0.00	17.56	76.93	NA
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	N2O	2042.4	mmBtu/hr	8760	Hours	2.20E-04	lb/mmBtu	40 CFR Part 98 Table C-1, Natural Gas	0.45	1.97	0.00	0.45	1.97	NA
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	CO2e	2042.4	mmBtu/hr	8760	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	986,539	0.00	NA	986,539	NA
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	CO	2042.4	mmBtu/hr	8760	Hours	3.88E+01	lb/hr	Worst-case based on performance testing; annual values include SU/SD	38.80	196.28	0.00	38.80	196.28	[2]

Emission Unit ID	Old Emission Unit ID	Stack ID	Old Stack ID	Unit Name	Fuel	Pollutant	Max Hourly Process Rate	Process Rate Units	Max Annual Utilization	Units	Emission Factor	Emission Factor Units	Emission Factor Source	Emission Rate (lb/hr)	Uncontrolled PTE (ton/yr)	Pollution Control Efficiency (%)	Worst Case Controlled PTE (lb/hr)	Worst Case Controlled PTE (ton/yr)	Limited PTE Existing Permit (ton/yr)
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	NOx	2042.4	mmBtu/hr	8760	Hours	7.35E+01	lb/hr	Worst-case based on performance testing; annual values include SU/SD	73.51	330.10	0.00	73.51	330.10	[2]
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	PM	2042.4	mmBtu/hr	8760	Hours	6.60E-03	lb/mmBtu	AP-42 Table 3.1-2a	13.48	59.04	0.00	13.48	59.04	[2]
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	PM10	2042.4	mmBtu/hr	8760	Hours	6.60E-03	lb/mmBtu	Assumed equal to PM	13.48	59.04	0.00	13.48	59.04	[2]
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	PM2.5	2042.4	mmBtu/hr	8760	Hours	6.60E-03	lb/mmBtu	Assumed equal to PM	13.48	59.04	0.00	13.48	59.04	NA
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	SO2	1.9	MMSCF/hr	8760	Hours	6.00E-01	lb/mmBtu	AP-42 Table 1.4-2 [3]	1.17	5.11	0.00	1.17	5.11	[2]
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	VOC	2042.4	mmBtu/hr	8760	Hours	1.00E+01	lb/hr	Calculated lb/hr from BACT ppm concentration; annual values include SU/SD	10.03	76.73	0.00	10.03	76.73	[2]
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	CO2	2042.4	mmBtu/hr	8760	Hours	1.10E+02	lb/mmBtu	AP-42 Table 3.1-2a	224664.00	984028.32	0.00	224664.00	984028.32	NA
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	CH4	2042.4	mmBtu/hr	8760	Hours	8.60E-03	lb/mmBtu	AP-42 Table 3.1-2a	17.56	76.93	0.00	17.56	76.93	NA
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	N2O	2042.4	mmBtu/hr	8760	Hours	2.20E-04	lb/mmBtu	40 CFR Part 98 Table C-1, Natural Gas	0.45	1.97	0.00	0.45	1.97	NA
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	CO2e	2042.4	mmBtu/hr	8760	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	986539	0.00	NA	986539	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	CO	79.6	mmBtu/hr	8760.00	Hours	3.78E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	3.78	20.00	0.00	3.78	20.00	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	NOx	79.6	mmBtu/hr	8760.00	Hours	1.09E+01	lb/hr	BACT Engine Specifications; annual values include SU/SD	10.86	63.32	0.00	10.86	63.32	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	PM	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	Assumed equal to PM10; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	PM10	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	PM2.5	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	SO2	79.6	mmBtu/hr	8760.00	Hours	1.52E-03	lb/mmBtu	AP-42 Table 3.4-1	0.120594	0.53	0.00	0.12	0.53	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	VOC	79.6	mmBtu/hr	8760.00	Hours	4.33E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.33	19.40	0.00	4.33	19.40	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	CO2	79.6	mmBtu/hr	8760.00	Hours	1.65E+04	lb/hr	BACT Engine Specifications	16540.00	72445.20	0.00	16540.00	72445.20	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	CH4	79.6	mmBtu/hr	8760.00	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.53	2.31	0.00	0.53	2.31	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	N2O	79.6	mmBtu/hr	8760.00	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.11	0.46	0.00	0.11	0.46	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	CO2e	79.6	mmBtu/hr	8760.00	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	72640	0.00	NA	72640	NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	CO	77.7	mmBtu/hr	8760.00	Hours	2.51E+00	lb/hr	BACT Engine Specifications	2.51	10.99	0.00	2.51		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	NOx	77.7	mmBtu/hr	8760.00	Hours	1.65E+00	lb/hr	BACT Engine Specifications	1.65	7.23	0.00	1.65		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	PM	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	Assumed equal to PM10	2.01	8.80	0.00	2.01		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	PM10	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	BACT Engine Specifications	2.01	8.80	0.00	2.01		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	PM2.5	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	BACT Engine Specifications	2.01	8.80	0.00	2.01		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	SO2	77.7	mmBtu/hr	8760.00	Hours	6.12E-04	lb/mmBtu	AP-42 Table 3.4-1 [4]	0.00	0.00	0.00	0.00		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	VOC	77.7	mmBtu/hr	8760.00	Hours	3.26E+00	lb/hr	BACT Engine Specifications	3.26	14.28	0.00	3.26		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	CO2	77.7	mmBtu/hr	8760.00	Hours	1.34E+04	lb/hr	BACT Engine Specifications	13440.00	58867.20	0.00	13440.00		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	CH4	77.7	mmBtu/hr	8760.00	Hours	1.00E-03	lb/mmBtu	40 CFR Part 98 Table C-2, natural gas	0.08	0.34	0.00	0.08		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	N2O	77.7	mmBtu/hr	8760.00	Hours	1.00E-04	lb/mmBtu	40 CFR Part 98 Table C-2, natural gas	0.01	0.03	0.00	0.01		NA
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	CO2e	77.7	mmBtu/hr	8760.00	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	58886	0.00	NA		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	CO	79.6	mmBtu/hr	8760.00	Hours	3.78E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	3.78	20.00	0.00	3.78	20.00	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	NOx	79.6	mmBtu/hr	8760.00	Hours	1.09E+01	lb/hr	BACT Engine Specifications; annual values include SU/SD	10.86	63.32	0.00	10.86	63.32	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	PM	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	Assumed equal to PM10; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	PM10	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	PM2.5	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	SO2	79.6	mmBtu/hr	8760.00	Hours	1.52E-03	lb/hr	AP-42 Table 3.4-1	0.12	0.53	0.00	0.12	0.53	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	VOC	79.6	mmBtu/hr	8760.00	Hours	4.33E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.33	19.40	0.00	4.33	19.40	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	CO2	79.6	mmBtu/hr	8760.00	Hours	1.65E+04	lb/hr	BACT Engine Specifications	16540.00	72445.20	0.00	16540.00	72445.20	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	CH4	79.6	mmBtu/hr	8760.00	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.53	2.31	0.00	0.53	2.31	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	N2O	79.6	mmBtu/hr	8760.00	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.11	0.46	0.00	0.11	0.46	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	CO2e	79.6	mmBtu/hr	8760.00	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	72640	0.00	NA	72640	NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	CO	77.7	mmBtu/hr	8760.00	Hours	2.51E+00	lb/hr	BACT Engine Specifications	2.51	10.99	0.00	2.51		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	NOx	77.7	mmBtu/hr	8760.00	Hours	1.65E+00	lb/hr	BACT Engine Specifications	1.65	7.23	0.00	1.65		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	PM	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	Assumed equal to PM10	2.01	8.80	0.00	2.01		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	PM10	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	BACT Engine Specifications	2.01	8.80	0.00	2.01		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	PM2.5	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	Assumed equal to PM10	2.01	8.80	0.00	2.01		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	SO2	77.7	mmBtu/hr	8760.00	Hours	6.12E-04	lb/mmBtu	AP-42 Table 3.4-1 [4]	0.00	0.00	0.00	0.00		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	VOC	77.7	mmBtu/hr	8760.00	Hours	3.26E+00	lb/hr	BACT Engine Specifications	3.26	14.28	0.00	3.26		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	CO2	77.7	mmBtu/hr	8760.00	Hours	1.34E+04	lb/hr	BACT Engine Specifications	13440.00	58867.20	0.00	13440.00		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	CH4	77.7	mmBtu/hr	8760.00	Hours	1.00E-03	lb/mmBtu	40 CFR Part 98 Table C-2, natural gas	0.08	0.34	0.00	0.08		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	N2O	77.7	mmBtu/hr	8760.00	Hours	1.00E-04	lb/mmBtu	40 CFR Part 98 Table C-2, natural gas	0.01	0.03	0.00	0.01		NA
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	CO2e	77.7	mmBtu/hr	8760.00	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	58886	0.00	NA		NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	CO	79.6	mmBtu/hr	8760.00	Hours	3.78E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	3.78	20.00	0.00	3.78	20.00	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	NOx	79.6	mmBtu/hr	8760.00	Hours	1.09E+01	lb/hr	BACT Engine Specifications; annual values include SU/SD	10.86	63.32	0.00	10.86	63.32	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	PM	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	Assumed equal to PM10; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	PM10	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	PM2.5	79.6	mmBtu/hr	8760.00	Hours	4.76E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.76	20.92	0.00	4.76	20.92	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	SO2	79.6	mmBtu/hr	8760.00	Hours	1.52E-03	lb/hr	AP-42 Table 3.4-1	0.12	0.53	0.00	0.12	0.53	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	VOC	79.6	mmBtu/hr	8760.00	Hours	4.33E+00	lb/hr	BACT Engine Specifications; annual values include SU/SD	4.33	19.40	0.00	4.33	19.40	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	CO2	79.6	mmBtu/hr	8760.00	Hours	1.65E+04	lb/hr	BACT Engine Specifications	16540.00	72445.20	0.00	16540.00	72445.20	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	CH4	79.6	mmBtu/hr	8760.00	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.53	2.31	0.00	0.53	2.31	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	N2O	79.6	mmBtu/hr	8760.00	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.11	0.46	0.00	0.11	0.46	NA
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	CO2e	79.6	mmBtu/hr	8760.00	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	72640	0.00	NA	72640	NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	CO	77.7	mmBtu/hr	8760.00	Hours	2.51E+00	lb/hr	BACT Engine Specifications	2.51	10.99	0.00	2.51		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	NOx	77.7	mmBtu/hr	8760.00	Hours	1.65E+00	lb/hr	BACT Engine Specifications	1.65	7.23	0.00	1.65		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	PM	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	Assumed equal to PM10	2.01	8.80	0.00	2.01		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	PM10	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	BACT Engine Specifications	2.01	8.80	0.00	2.01		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	PM2.5	77.7	mmBtu/hr	8760.00	Hours	2.01E+00	lb/hr	Assumed equal to PM10	2.01	8.80	0.00	2.01		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	SO2	77.7	mmBtu/hr	8760.00	Hours	6.12E-04	lb/hr	AP-42 Table 3.4-1 [4]	0.00	0.00	0.00	0.00		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	VOC	77.7	mmBtu/hr	8760.00	Hours	3.26E+00	lb/hr	BACT Engine Specifications	3.26	14.28	0.00	3.26		NA

Emission Unit ID	Old Emission Unit ID	Stack ID	Old Stack ID	Unit Name	Fuel	Pollutant	Max Hourly Process Rate	Process Rate Units	Max Annual Utilization	Units	Emission Factor	Emission Factor Units	Emission Factor Source	Emission Rate (lb/hr)	Uncontrolled PTE (ton/yr)	Pollution Control Efficiency (%)	Worst Case Controlled PTE (lb/hr)	Worst Case Controlled PTE (ton/yr)	Limited PTE Existing Permit (ton/yr)
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	CO2	77.7	mmBtu/hr	8760.00	Hours	1.34E+04	lb/hr	BACT Engine Specifications	13440.00	58867.20	0.00	13440.00		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	CH4	77.7	mmBtu/hr	8760.00	Hours	1.00E-03	lb/mmBtu	40 CFR Part 98 Table C-2, natural gas	0.08	0.34	0.00	0.08		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	N2O	77.7	mmBtu/hr	8760.00	Hours	1.00E-04	lb/mmBtu	40 CFR Part 98 Table C-2, natural gas	0.01	0.03	0.00	0.01		NA
EQUI 25	NA	STRU 26	NA	Natural Gas	Natural Gas	CO2e	77.7	mmBtu/hr	8760.00	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	58,885.85	0.00	NA		NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	CO	1048.6	hp	500	Hours	5.75E-03	lb/hp-hr	NSPS IIII	6.03	1.51	0.00	6.03	1.51	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	NOx	1048.6	hp	500	Hours	1.05E-02	lb/hp-hr	NSPS IIII	11.03	2.76	0.00	11.03	2.76	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	PM	1048.6	hp	500	Hours	3.29E-04	lb/hp-hr	NSPS IIII	0.34	0.09	0.00	0.34	0.09	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	PM10	1048.6	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII filterable with AP-42 PM-COND	0.39	0.10	0.00	0.39	0.10	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	PM2.5	1048.6	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII, Assumed equal to PM10	0.39	0.10	0.00	0.39	0.10	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	SO2	7.6	mmBtu/hr	500	Hours	1.52E-03	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	0.01	0.00	0.00	0.01	0.00	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	VOC	7.6	mmBtu/hr	500	Hours	9.00E-02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled TOC	0.68	0.17	0.00	0.68	0.17	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	CO2	7.6	mmBtu/hr	500	Hours	1.65E+02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	1252.02	313.01	0.00	1252.02	313.01	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	CH4	7.6	mmBtu/hr	500	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.05	0.01	0.00	0.05	0.01	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	N2O	7.6	mmBtu/hr	500	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-2, petroleum products	0.01	0.00	0.00	0.01	0.00	NA
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	CO2e	7.6	mmBtu/hr	500	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	314	0.00	NA	314	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	CO	1048.6	hp	500	Hours	5.75E-03	lb/hp-hr	NSPS IIII	6.03	1.51	0.00	6.03	1.51	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	NOx	1048.6	hp	500	Hours	1.05E-02	lb/hp-hr	NSPS IIII	11.03	2.76	0.00	11.03	2.76	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	PM	1048.6	hp	500	Hours	3.29E-04	lb/hp-hr	NSPS IIII	0.34	0.09	0.00	0.34	0.09	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	PM10	1048.6	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII filterable with AP-42 PM-COND	0.39	0.10	0.00	0.39	0.10	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	PM2.5	1048.6	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII, Assumed equal to PM10	0.39	0.10	0.00	0.39	0.10	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	SO2	7.6	mmBtu/hr	500	Hours	1.52E-03	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	0.01	0.00	0.00	0.01	0.00	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	VOC	7.6	mmBtu/hr	500	Hours	9.00E-02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled TOC	0.68	0.17	0.00	0.68	0.17	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	CO2	7.6	mmBtu/hr	500	Hours	1.65E+02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	1252.02	313.01	0.00	1252.02	313.01	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	CH4	7.6	mmBtu/hr	500	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.05	0.01	0.00	0.05	0.01	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	N2O	7.6	mmBtu/hr	500	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.01	0.00	0.00	0.01	0.00	NA
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	CO2e	7.6	mmBtu/hr	500	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	314	0.00	NA	314	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	CO	1048.6	hp	500	Hours	5.75E-03	lb/hp-hr	NSPS IIII	6.03	1.51	0.00	6.03	1.51	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	NOx	1048.6	hp	500	Hours	1.05E-02	lb/hp-hr	NSPS IIII	11.03	2.76	0.00	11.03	2.76	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	PM	1048.6	hp	500	Hours	3.29E-04	lb/hp-hr	NSPS IIII	0.34	0.09	0.00	0.34	0.09	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	PM10	1048.6	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII filterable with AP-42 PM-COND	0.39	0.10	0.00	0.39	0.10	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	PM2.5	1048.6	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII, Assumed equal to PM10	0.39	0.10	0.00	0.39	0.10	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	SO2	7.6	mmBtu/hr	500	Hours	1.52E-03	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	0.01	0.00	0.00	0.01	0.00	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	VOC	7.6	mmBtu/hr	500	Hours	9.00E-02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled TOC	0.68	0.17	0.00	0.68	0.17	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	CO2	7.6	mmBtu/hr	500	Hours	1.65E+02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	1252.02	313.01	0.00	1252.02	313.01	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	CH4	7.6	mmBtu/hr	500	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.05	0.01	0.00	0.05	0.01	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	N2O	7.6	mmBtu/hr	500	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.01	0.00	0.00	0.01	0.00	NA
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	CO2e	7.6	mmBtu/hr	500	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	314	0.00	NA	314	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	CO	771.9	hp	500	Hours	5.75E-03	lb/hp-hr	NSPS IIII	4.44	1.11	0.00	4.44	1.11	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	NOx	771.9	hp	500	Hours	1.05E-02	lb/hp-hr	NSPS IIII	8.12	2.03	0.00	8.12	2.03	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	PM	771.9	hp	500	Hours	3.29E-04	lb/hp-hr	NSPS IIII	0.25	0.06	0.00	0.25	0.06	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	PM10	771.9	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII filterable with AP-42 PM-COND	0.29	0.07	0.00	0.29	0.07	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	PM2.5	771.9	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII, Assumed equal to PM10	0.29	0.07	0.00	0.29	0.07	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	SO2	5.6	mmBtu/hr	500	Hours	1.52E-03	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	0.01	0.00	0.00	0.01	0.00	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	VOC	5.6	mmBtu/hr	500	Hours	9.00E-02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled TOC	0.50	0.13	0.00	0.50	0.13	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	CO2	5.6	mmBtu/hr	500	Hours	1.65E+02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	921.69	230.42	0.00	921.69	230.42	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	CH4	5.6	mmBtu/hr	500	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.04	0.01	0.00	0.04	0.01	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	N2O	5.6	mmBtu/hr	500	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.01	0.00	0.00	0.01	0.00	NA
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	CO2e	5.6	mmBtu/hr	500	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	231	0.00	NA	231	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	CO	771.9	hp	500	Hours	5.75E-03	lb/hp-hr	NSPS IIII	4.44	1.11	0.00	4.44	1.11	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	NOx	771.9	hp	500	Hours	1.05E-02	lb/hp-hr	NSPS IIII	8.12	2.03	0.00	8.12	2.03	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	PM	771.9	hp	500	Hours	3.29E-04	lb/hp-hr	NSPS IIII	0.25	0.06	0.00	0.25	0.06	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	PM10	771.9	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII filterable with AP-42 PM-COND	0.29	0.07	0.00	0.29	0.07	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	PM2.5	771.9	hp	500	Hours	3.70E-04	lb/hp-hr	NSPS IIII, Assumed equal to PM10	0.29	0.07	0.00	0.29	0.07	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	SO2	5.6	mmBtu/hr	500	Hours	1.52E-03	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	0.01	0.00	0.00	0.01	0.00	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	VOC	5.6	mmBtu/hr	500	Hours	9.00E-02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled TOC	0.50	0.13	0.00	0.50	0.13	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	CO2	5.6	mmBtu/hr	500	Hours	1.65E+02	lb/mmBtu	AP-42 Table 3.4-1, Diesel Fuel, Uncontrolled	921.69	230.42	0.00	921.69	230.42	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	CH4	5.6	mmBtu/hr	500	Hours	6.61E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.04	0.01	0.00	0.04	0.01	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	N2O	5.6	mmBtu/hr	500	Hours	1.32E-03	lb/mmBtu	40 CFR Part 98 Table C-1, petroleum products	0.01	0.00	0.00	0.01	0.00	NA
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	CO2e	5.6	mmBtu/hr	500	Hours	NA	NA	40 CFR Part 98 Table A-1 (Footnote 1)	NA	231	0.00	NA	231	NA

Footnotes:

[1] CO2e calculated based on 40 CFR Part 98 Table A-1 global warming potentials:

CO2	1
CH4	25
N2O	298

[2] Limited emissions for both natural gas fired turbines are assigned arbitrarily to Unit 7 (EQUI 7)

[3] Emission factor for external combustion boiler, but this factor is representative of natural gas with only sulfur due to added mercaptan.

[4] Assumes 15 PPM sulfur for diesel fuel and 6 PPM sulfur for natural gas and 95% natural gas; 5% diesel.

Xcel Energy
Blue Lake Conversion Project
HAP Emissions - Standard Emission Factors and No Hour Limits
12/16/2022

	Controlled PTE	
Pollutant	**Facility Sum (ton/year) Post Mod**	**Facility Sum (lb/hr) Post Mod**
1,3-Butadiene	0.28	0.07
Benzene	1.03	0.24
Formaldehyde	10.47	2.39
Naphthalene	0.16	0.04
Arsenic	0	0
Beryllium	0	0
Cadmium	0	0
Chromium	0	0
Lead	0	0
Manganese	0	0
Mercury	0	0
Nickel	0	0
Selenium	0	0
Toluene	2.75	0.64
Xylenes	1.35	0.31
Acetaldehyde	9.25	2.11
Acrolein	5.36	1.23
Total PAH	0.26	0.07
Ethylbenzene	0.61	0.14
Propylene Oxide	0.52	0.12
1,1,2,2-TETRACHLOROETHANE	0.04	0.01
1,1,2-Trichloroethane	0.03	0.01
1,1-Dichloroethane	0.02	0.01
1,2,4-Trimethylbenzene	0.01	3.33E-03
1,2-Dichloroethane	0.02	0.01
Propylene Dichloride	0.03	0.01
1,3,5-Trimethylbenzene	0.03	0.01
1,3-Dichloropropene	0.03	0.01
2-Methylnaphthalene	0.03	0.01
Isooctane	0.26	0.06
Acenaphthene	1.28E-03	2.91E-04
Acenaphthylene	0.01	1.29E-03
Benzo(b)fluoranthene	1.69E-04	3.87E-05
Benzo(e)pyrene	4.24E-04	9.67E-05
Benzo(g,h,i)perylene	4.23E-04	9.65E-05
Biphenyl	0.22	0.05
Carbon Tetrachloride	0.04	0.01
Chlorobenzene	0.03	0.01
Chloroethane	1.91E-03	4.36E-04
Chloroform	0.03	0.01
Benzo(a)phenanthrene	7.08E-04	1.62E-04
1,2-Dibromoethane	0.05	0.01
Fluoranthene	1.13E-03	2.59E-04
Fluorene	0.01	1.32E-03
Methanol	2.55	0.58
Methylene Chloride	0.02	4.66E-03

Xcel Energy
Blue Lake Conversion Project
HAP Emissions - Standard Emission Factors and No Hour Limits
12/16/2022

	Controlled PTE	
Pollutant	**Facility Sum (ton/year) Post Mod**	**Facility Sum (lb/hr) Post Mod**
n-Hexane	1.13	0.26
Naphthalene	0.16	0.04
Phenanthrene	0.01	2.42E-03
Phenol	0.02	0.01
Pyrene	1.39E-03	3.17E-04
Styrene	0.02	0.01
Vinyl Chloride	0.02	3.47E-03
Facility Total HAPs	36.9	8.5
Facility Limited Total HAPs [1]	22.5	NA
Highest Individual HAP	Formaldehyde	Formaldehyde
Highest Individual HAP	10.5	2.4
Facility Limited PTE single HAP [1]	9.0	NA

[1] Xcel is proposing to incorporate the new emission units into the existing cap of 9.0 tpy on single HAPs and 22.5 tpy on total HAPs such that the facility remain a minor source of HAPs.

Xcel Energy
Blue Lake Conversion Project
HAP Emissions - Standard Emission Factors and No Hour Limits
12/16/2022

Emission Unit ID	Old Emission Unit ID	Stack ID	Old Stack ID	Unit Name	Fuel	Pollutant	Max Hourly Process Rate	Process Rate Units	Max Annual Utilization	Units	Emission Factor	Emission Factor Units	Emission Factor Source	Emission Rate (lb/hr)	Uncontrolled PTE (ton/yr)	Pollution Control Efficiency (%)	Worst Case Controlled PTE (lb/hr) [1]	Worst Case PTE (ton/yr) [2]
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	1,3-Butadiene	648	mmBtu/hr	8760	Hours	1.60E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	1.04E-02	4.54E-02	0%	1.04E-02	4.54E-02
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Benzene	648	mmBtu/hr	8760	Hours	5.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	3.56E-02	1.56E-01	0%	3.56E-02	1.56E-01
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Formaldehyde	648	mmBtu/hr	8760	Hours	2.80E-04	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	1.81E-01	7.95E-01	0%	1.81E-01	7.95E-01
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Naphthalene	648	mmBtu/hr	8760	Hours	3.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.27E-02	9.93E-02	0%	2.27E-02	9.93E-02
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	PAH	648	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.59E-02	1.14E-01	0%	2.59E-02	1.14E-01
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Arsenic	648	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.13E-03	3.12E-02	0%	7.13E-03	3.12E-02
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Beryllium	648	mmBtu/hr	8760	Hours	3.10E-07	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	2.01E-04	8.80E-04	0%	2.01E-04	8.80E-04
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Cadmium	648	mmBtu/hr	8760	Hours	4.80E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	3.11E-03	1.36E-02	0%	3.11E-03	1.36E-02
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Chromium	648	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.13E-03	3.12E-02	0%	7.13E-03	3.12E-02
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Lead	648	mmBtu/hr	8760	Hours	1.40E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	9.07E-03	3.97E-02	0%	9.07E-03	3.97E-02
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Manganese	648	mmBtu/hr	8760	Hours	7.90E-04	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	5.12E-01	2.24E+00	0%	5.12E-01	2.24E+00
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Mercury	648	mmBtu/hr	8760	Hours	1.20E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.78E-04	3.41E-03	0%	7.78E-04	3.41E-03
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Nickel	648	mmBtu/hr	8760	Hours	4.60E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	2.98E-03	1.31E-02	0%	2.98E-03	1.31E-02
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	Selenium	648	mmBtu/hr	8760	Hours	2.50E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	1.62E-02	7.10E-02	0%	1.62E-02	7.10E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	1,3-Butadiene	648	mmBtu/hr	8760	Hours	1.60E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	1.04E-02	4.54E-02	0%	1.04E-02	4.54E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Benzene	648	mmBtu/hr	8760	Hours	5.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	3.56E-02	1.56E-01	0%	3.56E-02	1.56E-01
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Formaldehyde	648	mmBtu/hr	8760	Hours	2.80E-04	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	1.81E-01	7.95E-01	0%	1.81E-01	7.95E-01
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Naphthalene	648	mmBtu/hr	8760	Hours	3.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.27E-02	9.93E-02	0%	2.27E-02	9.93E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	PAH	648	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.59E-02	1.14E-01	0%	2.59E-02	1.14E-01
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Arsenic	648	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.13E-03	3.12E-02	0%	7.13E-03	3.12E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Beryllium	648	mmBtu/hr	8760	Hours	3.10E-07	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	2.01E-04	8.80E-04	0%	2.01E-04	8.80E-04
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Cadmium	648	mmBtu/hr	8760	Hours	4.80E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	3.11E-03	1.36E-02	0%	3.11E-03	1.36E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Chromium	648	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.13E-03	3.12E-02	0%	7.13E-03	3.12E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Lead	648	mmBtu/hr	8760	Hours	1.40E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	9.07E-03	3.97E-02	0%	9.07E-03	3.97E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Manganese	648	mmBtu/hr	8760	Hours	7.90E-04	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	5.12E-01	2.24E+00	0%	5.12E-01	2.24E+00
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Mercury	648	mmBtu/hr	8760	Hours	1.20E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.78E-04	3.41E-03	0%	7.78E-04	3.41E-03
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Nickel	648	mmBtu/hr	8760	Hours	4.60E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	2.98E-03	1.31E-02	0%	2.98E-03	1.31E-02
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	Selenium	648	mmBtu/hr	8760	Hours	2.50E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	1.62E-02	7.10E-02	0%	1.62E-02	7.10E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	1,3-Butadiene	648	mmBtu/hr	8760	Hours	1.60E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	1.04E-02	4.54E-02	0%	1.04E-02	4.54E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Benzene	648	mmBtu/hr	8760	Hours	5.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	3.56E-02	1.56E-01	0%	3.56E-02	1.56E-01
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Formaldehyde	648	mmBtu/hr	8760	Hours	2.80E-04	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	1.81E-01	7.95E-01	0%	1.81E-01	7.95E-01
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Naphthalene	648	mmBtu/hr	8760	Hours	3.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.27E-02	9.93E-02	0%	2.27E-02	9.93E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	PAH	648	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.59E-02	1.14E-01	0%	2.59E-02	1.14E-01
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Arsenic	648	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.13E-03	3.12E-02	0%	7.13E-03	3.12E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Beryllium	648	mmBtu/hr	8760	Hours	3.10E-07	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	2.01E-04	8.80E-04	0%	2.01E-04	8.80E-04
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Cadmium	648	mmBtu/hr	8760	Hours	4.80E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	3.11E-03	1.36E-02	0%	3.11E-03	1.36E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Chromium	648	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.13E-03	3.12E-02	0%	7.13E-03	3.12E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Lead	648	mmBtu/hr	8760	Hours	1.40E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	9.07E-03	3.97E-02	0%	9.07E-03	3.97E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Manganese	648	mmBtu/hr	8760	Hours	7.90E-04	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	5.12E-01	2.24E+00	0%	5.12E-01	2.24E+00
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Mercury	648	mmBtu/hr	8760	Hours	1.20E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	7.78E-04	3.41E-03	0%	7.78E-04	3.41E-03
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Nickel	648	mmBtu/hr	8760	Hours	4.60E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	2.98E-03	1.31E-02	0%	2.98E-03	1.31E-02
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	Selenium	648	mmBtu/hr	8760	Hours	2.50E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	1.62E-02	7.10E-02	0%	1.62E-02	7.10E-02
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	1,3-Butadiene	740	mmBtu/hr	8760	Hours	1.60E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	1.18E-02	5.19E-02	0%	1.18E-02	5.19E-02
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Benzene	740	mmBtu/hr	8760	Hours	5.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	4.07E-02	1.78E-01	0%	4.07E-02	1.78E-01
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Formaldehyde	740	mmBtu/hr	8760	Hours	2.80E-04	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.07E-01	9.08E-01	0%	2.07E-01	9.08E-01
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Naphthalene	740	mmBtu/hr	8760	Hours	3.50E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.59E-02	1.13E-01	0%	2.59E-02	1.13E-01
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	PAH	740	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.1-4, Uncontrolled	2.96E-02	1.30E-01	0%	2.96E-02	1.30E-01
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Arsenic	740	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	8.14E-03	3.57E-02	0%	8.14E-03	3.57E-02
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Beryllium	740	mmBtu/hr	8760	Hours	3.10E-07	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	2.29E-04	1.00E-03	0%	2.29E-04	1.00E-03
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Cadmium	740	mmBtu/hr	8760	Hours	4.80E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	3.55E-03	1.56E-02	0%	3.55E-03	1.56E-02
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Chromium	740	mmBtu/hr	8760	Hours	1.10E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	8.14E-03	3.57E-02	0%	8.14E-03	3.57E-02
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Lead	740	mmBtu/hr	8760	Hours	1.40E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	1.04E-02	4.54E-02	0%	1.04E-02	4.54E-02
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Manganese	740	mmBtu/hr	8760	Hours	7.90E-04	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	5.85E-01	2.56E+00	0%	5.85E-01	2.56E+00
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Mercury	740	mmBtu/hr	8760	Hours	1.20E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	8.88E-04	3.89E-03	0%	8.88E-04	3.89E-03
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Nickel	740	mmBtu/hr	8760	Hours	4.60E-06	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	3.40E-03	1.49E-02	0%	3.40E-03	1.49E-02

EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	Selenium	740	mmBtu/hr	8760	Hours	2.50E-05	lb/mmBtu	AP-42 Table 3.1-5, Uncontrolled	1.85E-02	8.10E-02	0%	1.85E-02	8.10E-02
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	Benzene	1.1	mmBtu/hr	500	Hours	9.33E-04	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	1.03E-03	2.57E-04	0%	1.03E-03	2.57E-04
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	Toluene	1.1	mmBtu/hr	500	Hours	4.09E-04	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	4.50E-04	1.97E-03	0%	4.50E-04	1.97E-03
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	Xylenes	1.1	mmBtu/hr	500	Hours	2.85E-04	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	3.14E-04	1.37E-03	0%	3.14E-04	1.37E-03
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	1,3-Butadiene	1.1	mmBtu/hr	500	Hours	3.91E-05	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	4.30E-05	1.08E-05	0%	4.30E-05	1.08E-05
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	Formaldehyde	1.1	mmBtu/hr	500	Hours	1.18E-03	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	1.30E-03	3.25E-04	0%	1.30E-03	3.25E-04
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	Acetaldehyde	1.1	mmBtu/hr	500	Hours	7.67E-04	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	8.44E-04	2.11E-04	0%	8.44E-04	2.11E-04
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	Acrolein	1.1	mmBtu/hr	500	Hours	9.25E-04	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	1.02E-03	2.54E-04	0%	1.02E-03	2.54E-04
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	Total PAH	1.1	mmBtu/hr	500	Hours	1.68E-04	lb/mmBtu	AP-42 Table 3.3-2, Uncontrolled	1.85E-04	4.62E-05	0%	1.85E-04	4.62E-05
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	1,3-Butadiene	2042.4	mmBtu/hr	8760	Hours	4.30E-07	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	8.78E-04	3.85E-03	0%	8.78E-04	3.85E-03
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Acetaldehyde	2042.4	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	8.17E-02	3.58E-01	0%	8.17E-02	3.58E-01
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Acrolein	2042.4	mmBtu/hr	8760	Hours	6.40E-06	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	1.31E-02	5.73E-02	0%	1.31E-02	5.73E-02
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Benzene	2042.4	mmBtu/hr	8760	Hours	1.20E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	2.45E-02	1.07E-01	0%	2.45E-02	1.07E-01
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Ethylbenzene	2042.4	mmBtu/hr	8760	Hours	3.20E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	6.54E-02	2.86E-01	0%	6.54E-02	2.86E-01
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Formaldehyde	2042.4	mmBtu/hr	8760	Hours	4.00E-04	lb/mmBtu	Stack test on similar units	8.17E-01	3.58E+00	0%	8.17E-01	3.58E+00
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Naphthalene	2042.4	mmBtu/hr	8760	Hours	1.30E-06	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	2.66E-03	1.16E-02	0%	2.66E-03	1.16E-02
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Total PAH	2042.4	mmBtu/hr	8760	Hours	2.20E-06	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	4.49E-03	1.97E-02	0%	4.49E-03	1.97E-02
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Propylene Oxide	2042.4	mmBtu/hr	8760	Hours	2.90E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	5.92E-02	2.59E-01	0%	5.92E-02	2.59E-01
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Toluene	2042.4	mmBtu/hr	8760	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	2.66E-01	1.16E+00	0%	2.66E-01	1.16E+00
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	Xylenes	2042.4	mmBtu/hr	8760	Hours	6.40E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	1.31E-01	5.73E-01	0%	1.31E-01	5.73E-01
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	1,3-Butadiene	2042.4	mmBtu/hr	8760	Hours	4.30E-07	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	8.78E-04	3.85E-03	0%	8.78E-04	3.85E-03
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Acetaldehyde	2042.4	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	8.17E-02	3.58E-01	0%	8.17E-02	3.58E-01
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Acrolein	2042.4	mmBtu/hr	8760	Hours	6.40E-06	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	1.31E-02	5.73E-02	0%	1.31E-02	5.73E-02
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Benzene	2042.4	mmBtu/hr	8760	Hours	1.20E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	2.45E-02	1.07E-01	0%	2.45E-02	1.07E-01
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Ethylbenzene	2042.4	mmBtu/hr	8760	Hours	3.20E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	6.54E-02	2.86E-01	0%	6.54E-02	2.86E-01
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Formaldehyde	2042.4	mmBtu/hr	8760	Hours	4.00E-04	lb/mmBtu	Stack test on similar units	8.17E-01	3.58E+00	0%	8.17E-01	3.58E+00
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Naphthalene	2042.4	mmBtu/hr	8760	Hours	1.30E-06	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	2.66E-03	1.16E-02	0%	2.66E-03	1.16E-02
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Total PAH	2042.4	mmBtu/hr	8760	Hours	2.20E-06	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	4.49E-03	1.97E-02	0%	4.49E-03	1.97E-02
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Propylene Oxide	2042.4	mmBtu/hr	8760	Hours	2.90E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	5.92E-02	2.59E-01	0%	5.92E-02	2.59E-01
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Toluene	2042.4	mmBtu/hr	8760	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	2.66E-01	1.16E+00	0%	2.66E-01	1.16E+00
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	Xylenes	2042.4	mmBtu/hr	8760	Hours	6.40E-05	lb/mmBtu	AP-42 Table 3.1-3, Uncontrolled	1.31E-01	5.73E-01	0%	1.31E-01	5.73E-01
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Benzene	79.6	mmBtu/hr	8760	Hours	7.76E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.18E-02	2.71E-01	0%	6.18E-02	2.71E-01
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Toluene	79.6	mmBtu/hr	8760	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.24E-02	9.80E-02	0%		
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Xylenes	79.6	mmBtu/hr	8760	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.54E-02	6.73E-02	0%	1.54E-02	6.73E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Naphthalene	79.6	mmBtu/hr	8760	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.03E-02	4.53E-02	0%	1.03E-02	4.53E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Formaldehyde	79.6	mmBtu/hr	8760	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.28E-03	2.75E-02	0%		
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Acetaldehyde	79.6	mmBtu/hr	8760	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.01E-03	8.79E-03	0%		
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Acrolein	79.6	mmBtu/hr	8760	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.27E-04	2.75E-03	0%		
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	Total PAH	79.6	mmBtu/hr	8760	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.69E-02	7.39E-02	0%	1.69E-02	7.39E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,1,2,2-TETRACHLOROETHANE	77.7	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.11E-03	1.36E-02	0%	3.11E-03	1.36E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,1,2-Trichloroethane	77.7	mmBtu/hr	8760	Hours	3.18E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.47E-03	1.08E-02	0%	2.47E-03	1.08E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,1-Dichloroethane	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,2,4-Trimethylbenzene	77.7	mmBtu/hr	8760	Hours	1.43E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.11E-03	4.87E-03	0%	1.11E-03	4.87E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,2-Dichloroethane	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Propylene Dichloride	77.7	mmBtu/hr	8760	Hours	2.69E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.09E-03	9.15E-03	0%	2.09E-03	9.15E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,3,5-Trimethylbenzene	77.7	mmBtu/hr	8760	Hours	3.38E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.63E-03	1.15E-02	0%	2.63E-03	1.15E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,3-Butadiene	77.7	mmBtu/hr	8760	Hours	2.67E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.07E-02	9.09E-02	0%	2.07E-02	9.09E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,3-Dichloropropene	77.7	mmBtu/hr	8760	Hours	2.64E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.05E-03	8.98E-03	0%	2.05E-03	8.98E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	2-Methylnaphthalene	77.7	mmBtu/hr	8760	Hours	3.32E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.58E-03	1.13E-02	0%	2.58E-03	1.13E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Isooctane	77.7	mmBtu/hr	8760	Hours	2.50E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.94E-02	8.51E-02	0%	1.94E-02	8.51E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Acenaphthene	77.7	mmBtu/hr	8760	Hours	1.25E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	9.71E-05	4.25E-04	0%	9.71E-05	4.25E-04
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Acenaphthylene	77.7	mmBtu/hr	8760	Hours	5.53E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	4.30E-04	1.88E-03	0%	4.30E-04	1.88E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Acetaldehyde	77.7	mmBtu/hr	8760	Hours	8.36E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	6.50E-01	2.85E+00	0%	6.50E-01	2.85E+00
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Acrolein	77.7	mmBtu/hr	8760	Hours	5.14E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.99E-01	1.75E+00	0%	3.99E-01	1.75E+00
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Benzene	77.7	mmBtu/hr	8760	Hours	4.40E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.42E-02	1.50E-01	0%		
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Benzo(b)fluoranthene	77.7	mmBtu/hr	8760	Hours	1.66E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.29E-05	5.65E-05	0%	1.29E-05	5.65E-05
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Benzo(e)pyrene	77.7	mmBtu/hr	8760	Hours	4.15E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.22E-05	1.41E-04	0%	3.22E-05	1.41E-04
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Benzo(g,h,i)perylene	77.7	mmBtu/hr	8760	Hours	4.14E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.22E-05	1.41E-04	0%	3.22E-05	1.41E-04
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Biphenyl	77.7	mmBtu/hr	8760	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.65E-02	7.21E-02	0%	1.65E-02	7.21E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Carbon Tetrachloride	77.7	mmBtu/hr	8760	Hours	3.67E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.85E-03	1.25E-02	0%	2.85E-03	1.25E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Chlorobenzene	77.7	mmBtu/hr	8760	Hours	3.04E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.36E-03	1.03E-02	0%	2.36E-03	1.03E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Chloroethane	77.7	mmBtu/hr	8760	Hours	1.87E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.45E-04	6.36E-04	0%	1.45E-04	6.36E-04
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Chloroform	77.7	mmBtu/hr	8760	Hours	2.85E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.21E-03	9.70E-03	0%	2.21E-03	9.70E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Benzo(a)phenanthrene	77.7	mmBtu/hr	8760	Hours	6.93E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	5.38E-05	2.36E-04	0%	5.38E-05	2.36E-04
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Ethylbenzene	77.7	mmBtu/hr	8760	Hours	3.97E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.08E-03	1.35E-02	0%	3.08E-03	1.35E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	1,2-Dibromoethane	77.7	mmBtu/hr	8760	Hours	4.43E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.44E-03	1.51E-02	0%	3.44E-03	1.51E-02
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Fluoranthene	77.7	mmBtu/hr	8760	Hours	1.11E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.62E-05	3.78E-04	0%	8.62E-05	3.78E-04

EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Fluorene	77.7	mmBtu/hr	8760	Hours	5.67E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	4.41E-04	1.93E-03	0%	4.41E-04	1.93E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Formaldehyde	77.7	Mweh/hr	8760	Hours	3.24E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.52E-01	1.10E+00	0%	2.52E-01	1.10E+00
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Methanol	77.7	mmBtu/hr	8760	Hours	2.50E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.94E-01	8.51E-01	0%	1.94E-01	8.51E-01
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Methylene Chloride	77.7	mmBtu/hr	8760	Hours	2.00E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.55E-03	6.81E-03	0%	1.55E-03	6.81E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	n-Hexane	77.7	mmBtu/hr	8760	Hours	1.11E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.62E-02	3.78E-01	0%	8.62E-02	3.78E-01
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Naphthalene	77.7	mmBtu/hr	8760	Hours	7.44E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	5.78E-03	2.53E-02	0%		
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Total PAH	77.7	mmBtu/hr	8760	Hours	2.69E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.09E-03	9.15E-03	0%		
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Phenanthrene	77.7	mmBtu/hr	8760	Hours	1.04E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.08E-04	3.54E-03	0%	8.08E-04	3.54E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Phenol	77.7	mmBtu/hr	8760	Hours	2.40E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.86E-03	8.17E-03	0%	1.86E-03	8.17E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Pyrene	77.7	mmBtu/hr	8760	Hours	1.36E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.06E-04	4.63E-04	0%	1.06E-04	4.63E-04
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Styrene	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Tetrachloroethane	77.7	mmBtu/hr	8760	Hours	2.48E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.93E-04	8.44E-04	0%	1.93E-04	8.44E-04
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Toluene	77.7	mmBtu/hr	8760	Hours	4.08E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.17E-02	1.39E-01	0%	3.17E-02	1.39E-01
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Vinyl Chloride	77.7	mmBtu/hr	8760	Hours	1.49E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.16E-03	5.07E-03	0%	1.16E-03	5.07E-03
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	Xylenes (mixed isomers)	77.7	mmBtu/hr	8760	Hours	1.84E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.43E-02	6.26E-02	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Benzene	79.6	mmBtu/hr	8760	Hours	7.76E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.18E-02	2.71E-01	0%	6.18E-02	2.71E-01
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Toluene	79.6	mmBtu/hr	8760	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.24E-02	9.80E-02	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Xylenes	79.6	mmBtu/hr	8760	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.54E-02	6.73E-02	0%	1.54E-02	6.73E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Naphthalene	79.6	mmBtu/hr	8760	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.03E-02	4.53E-02	0%	1.03E-02	4.53E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Formaldehyde	79.6	mmBtu/hr	8760	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.28E-03	2.75E-02	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Acetaldehyde	79.6	mmBtu/hr	8760	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.01E-03	8.79E-03	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Acrolein	79.6	mmBtu/hr	8760	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.27E-04	2.75E-03	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	Total PAH	79.6	mmBtu/hr	8760	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.69E-02	7.39E-02	0%	1.69E-02	7.39E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,1,2,2-TETRACHLOROETHANE	77.7	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.11E-03	1.36E-02	0%	3.11E-03	1.36E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,1,2-Trichloroethane	77.7	mmBtu/hr	8760	Hours	3.18E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.47E-03	1.08E-02	0%	2.47E-03	1.08E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,1-Dichloroethane	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,2,4-Trimethylbenzene	77.7	mmBtu/hr	8760	Hours	1.43E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.11E-03	4.87E-03	0%	1.11E-03	4.87E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,2-Dichloroethane	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Propylene Dichloride	77.7	mmBtu/hr	8760	Hours	2.69E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.09E-03	9.15E-03	0%	2.09E-03	9.15E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,3,5-Trimethylbenzene	77.7	mmBtu/hr	8760	Hours	3.38E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.63E-03	1.15E-02	0%	2.63E-03	1.15E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,3-Butadiene	77.7	mmBtu/hr	8760	Hours	2.67E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.07E-02	9.09E-02	0%	2.07E-02	9.09E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,3-Dichloropropene	77.7	mmBtu/hr	8760	Hours	2.64E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.05E-03	8.98E-03	0%	2.05E-03	8.98E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	2-Methylnaphthalene	77.7	mmBtu/hr	8760	Hours	3.32E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.58E-03	1.13E-02	0%	2.58E-03	1.13E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Isooctane	77.7	mmBtu/hr	8760	Hours	2.50E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.94E-02	8.51E-02	0%	1.94E-02	8.51E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Acenaphthene	77.7	mmBtu/hr	8760	Hours	1.25E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	9.71E-05	4.25E-04	0%	9.71E-05	4.25E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Acenaphthylene	77.7	mmBtu/hr	8760	Hours	5.53E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	4.30E-04	1.88E-03	0%	4.30E-04	1.88E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Acetaldehyde	77.7	mmBtu/hr	8760	Hours	8.36E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	6.50E-01	2.85E+00	0%	6.50E-01	2.85E+00
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Acrolein	77.7	mmBtu/hr	8760	Hours	5.14E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.99E-01	1.75E+00	0%	3.99E-01	1.75E+00
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Benzene	77.7	mmBtu/hr	8760	Hours	4.40E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.42E-02	1.50E-01	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Benzo(b)fluoranthene	77.7	mmBtu/hr	8760	Hours	1.66E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.29E-05	5.65E-05	0%	1.29E-05	5.65E-05
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Benzo(e)pyrene	77.7	mmBtu/hr	8760	Hours	4.15E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.22E-05	1.41E-04	0%	3.22E-05	1.41E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Benzo(g,h,i)perylene	77.7	mmBtu/hr	8760	Hours	4.14E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.22E-05	1.41E-04	0%	3.22E-05	1.41E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Biphenyl	77.7	mmBtu/hr	8760	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.65E-02	7.21E-02	0%	1.65E-02	7.21E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Carbon Tetrachloride	77.7	mmBtu/hr	8760	Hours	3.67E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.85E-03	1.25E-02	0%	2.85E-03	1.25E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Chlorobenzene	77.7	mmBtu/hr	8760	Hours	3.04E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.36E-03	1.03E-02	0%	2.36E-03	1.03E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Chloroethane	77.7	mmBtu/hr	8760	Hours	1.87E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.45E-04	6.36E-04	0%	1.45E-04	6.36E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Chloroform	77.7	mmBtu/hr	8760	Hours	2.85E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.21E-03	9.70E-03	0%	2.21E-03	9.70E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Benzo(a)phenanthrene	77.7	mmBtu/hr	8760	Hours	6.93E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	5.38E-05	2.36E-04	0%	5.38E-05	2.36E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Ethylbenzene	77.7	mmBtu/hr	8760	Hours	3.97E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.08E-03	1.35E-02	0%	3.08E-03	1.35E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	1,2-Dibromoethane	77.7	mmBtu/hr	8760	Hours	4.43E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.44E-03	1.51E-02	0%	3.44E-03	1.51E-02
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Fluoranthene	77.7	mmBtu/hr	8760	Hours	1.11E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.62E-05	3.78E-04	0%	8.62E-05	3.78E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Fluorene	77.7	mmBtu/hr	8760	Hours	5.67E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	4.41E-04	1.93E-03	0%	4.41E-04	1.93E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Formaldehyde	77.7	MWeh/hr	8760	Hours	3.24E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.52E-01	1.10E+00	0%	2.52E-01	1.10E+00
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Methanol	77.7	mmBtu/hr	8760	Hours	2.50E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.94E-01	8.51E-01	0%	1.94E-01	8.51E-01
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Methylene Chloride	77.7	mmBtu/hr	8760	Hours	2.00E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.55E-03	6.81E-03	0%	1.55E-03	6.81E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	n-Hexane	77.7	mmBtu/hr	8760	Hours	1.11E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.62E-02	3.78E-01	0%	8.62E-02	3.78E-01
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Naphthalene	77.7	mmBtu/hr	8760	Hours	7.44E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	5.78E-03	2.53E-02	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Total PAH	77.7	mmBtu/hr	8760	Hours	2.69E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.09E-03	9.15E-03	0%		
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Phenanthrene	77.7	mmBtu/hr	8760	Hours	1.04E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.08E-04	3.54E-03	0%	8.08E-04	3.54E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Phenol	77.7	mmBtu/hr	8760	Hours	2.40E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.86E-03	8.17E-03	0%	1.86E-03	8.17E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Pyrene	77.7	mmBtu/hr	8760	Hours	1.36E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.06E-04	4.63E-04	0%	1.06E-04	4.63E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Styrene	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Tetrachloroethane	77.7	mmBtu/hr	8760	Hours	2.48E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.93E-04	8.44E-04	0%	1.93E-04	8.44E-04
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Toluene	77.7	mmBtu/hr	8760	Hours	4.08E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.17E-02	1.39E-01	0%	3.17E-02	1.39E-01
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Vinyl Chloride	77.7	mmBtu/hr	8760	Hours	1.49E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.16E-03	5.07E-03	0%	1.16E-03	5.07E-03
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	Xylenes (mixed isomers)	77.7	mmBtu/hr	8760	Hours	1.84E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.43E-02	6.26E-02	0%		
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Benzene	79.6	mmBtu/hr	8760	Hours	7.76E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.18E-02	2.71E-01	0%	6.18E-02	2.71E-01
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Toluene	79.6	mmBtu/hr	8760	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.24E-02	9.80E-02	0%		

EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Xylenes	79.6	mmBtu/hr	8760	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.54E-02	6.73E-02	0%	1.54E-02	6.73E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Naphthalene	79.6	mmBtu/hr	8760	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.03E-02	4.53E-02	0%	1.03E-02	4.53E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Formaldehyde	79.6	mmBtu/hr	8760	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.28E-03	2.75E-02	0%		
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Acetaldehyde	79.6	mmBtu/hr	8760	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.01E-03	8.79E-03	0%		
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Acrolein	79.6	mmBtu/hr	8760	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	6.27E-04	2.75E-03	0%		

EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	Total PAH	79.6	mmBtu/hr	8760	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.69E-02	7.39E-02	0%	1.69E-02	7.39E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,1,2,2-TETRACHLOROETHANE	77.7	mmBtu/hr	8760	Hours	4.00E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.11E-03	1.36E-02	0%	3.11E-03	1.36E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,1,2-Trichloroethane	77.7	mmBtu/hr	8760	Hours	3.18E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.47E-03	1.08E-02	0%	2.47E-03	1.08E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,1-Dichloroethane	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,2,4-Trimethylbenzene	77.7	mmBtu/hr	8760	Hours	1.43E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.11E-03	4.87E-03	0%	1.11E-03	4.87E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,2-Dichloroethane	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Propylene Dichloride	77.7	mmBtu/hr	8760	Hours	2.69E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.09E-03	9.15E-03	0%	2.09E-03	9.15E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,3,5-Trimethylbenzene	77.7	mmBtu/hr	8760	Hours	3.38E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.63E-03	1.15E-02	0%	2.63E-03	1.15E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,3-Butadiene	77.7	mmBtu/hr	8760	Hours	2.67E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.07E-02	9.09E-02	0%	2.07E-02	9.09E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,3-Dichloropropene	77.7	mmBtu/hr	8760	Hours	2.64E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.05E-03	8.98E-03	0%	2.05E-03	8.98E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	2-Methylnaphthalene	77.7	mmBtu/hr	8760	Hours	3.32E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.58E-03	1.13E-02	0%	2.58E-03	1.13E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Isooctane	77.7	mmBtu/hr	8760	Hours	2.50E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.94E-02	8.51E-02	0%	1.94E-02	8.51E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Acenaphthene	77.7	mmBtu/hr	8760	Hours	1.25E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	9.71E-05	4.25E-04	0%	9.71E-05	4.25E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Acenaphthylene	77.7	mmBtu/hr	8760	Hours	5.53E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	4.30E-04	1.88E-03	0%	4.30E-04	1.88E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Acetaldehyde	77.7	mmBtu/hr	8760	Hours	8.36E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	6.50E-01	2.85E+00	0%	6.50E-01	2.85E+00
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Acrolein	77.7	mmBtu/hr	8760	Hours	5.14E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.99E-01	1.75E+00	0%	3.99E-01	1.75E+00
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Benzene	77.7	mmBtu/hr	8760	Hours	4.40E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.42E-02	1.50E-01	0%		
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Benzo(b)fluoranthene	77.7	mmBtu/hr	8760	Hours	1.66E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.29E-05	5.65E-05	0%	1.29E-05	5.65E-05
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Benzo(e)pyrene	77.7	mmBtu/hr	8760	Hours	4.15E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.22E-05	1.41E-04	0%	3.22E-05	1.41E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Benzo(g,h,i)perylene	77.7	mmBtu/hr	8760	Hours	4.14E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.22E-05	1.41E-04	0%	3.22E-05	1.41E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Biphenyl	77.7	mmBtu/hr	8760	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.65E-02	7.21E-02	0%	1.65E-02	7.21E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Carbon Tetrachloride	77.7	mmBtu/hr	8760	Hours	3.67E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.85E-03	1.25E-02	0%	2.85E-03	1.25E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Chlorobenzene	77.7	mmBtu/hr	8760	Hours	3.04E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.36E-03	1.03E-02	0%	2.36E-03	1.03E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Chloroethane	77.7	mmBtu/hr	8760	Hours	1.87E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.45E-04	6.36E-04	0%	1.45E-04	6.36E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Chloroform	77.7	mmBtu/hr	8760	Hours	2.85E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.21E-03	9.70E-03	0%	2.21E-03	9.70E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Benzo(a)phenanthrene	77.7	mmBtu/hr	8760	Hours	6.93E-07	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	5.38E-05	2.36E-04	0%	5.38E-05	2.36E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Ethylbenzene	77.7	mmBtu/hr	8760	Hours	3.97E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.08E-03	1.35E-02	0%	3.08E-03	1.35E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	1,2-Dibromoethane	77.7	mmBtu/hr	8760	Hours	4.43E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.44E-03	1.51E-02	0%	3.44E-03	1.51E-02
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Fluoranthene	77.7	mmBtu/hr	8760	Hours	1.11E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.62E-05	3.78E-04	0%	8.62E-05	3.78E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Fluorene	77.7	mmBtu/hr	8760	Hours	5.67E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	4.41E-04	1.93E-03	0%	4.41E-04	1.93E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Formaldehyde	77.7	MWeh/hr	8760	Hours	3.24E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.52E-01	1.10E+00	0%	2.52E-01	1.10E+00
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Methanol	77.7	mmBtu/hr	8760	Hours	2.50E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.94E-01	8.51E-01	0%	1.94E-01	8.51E-01
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Methylene Chloride	77.7	mmBtu/hr	8760	Hours	2.00E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.55E-03	6.81E-03	0%	1.55E-03	6.81E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	n-Hexane	77.7	mmBtu/hr	8760	Hours	1.11E-03	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.62E-02	3.78E-01	0%	8.62E-02	3.78E-01
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Naphthalene	77.7	mmBtu/hr	8760	Hours	7.44E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	5.78E-03	2.53E-02	0%		
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Total PAH	77.7	mmBtu/hr	8760	Hours	2.69E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	2.09E-03	9.15E-03	0%		
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Phenanthrene	77.7	mmBtu/hr	8760	Hours	1.04E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	8.08E-04	3.54E-03	0%	8.08E-04	3.54E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Phenol	77.7	mmBtu/hr	8760	Hours	2.40E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.86E-03	8.17E-03	0%	1.86E-03	8.17E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Pyrene	77.7	mmBtu/hr	8760	Hours	1.36E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.06E-04	4.63E-04	0%	1.06E-04	4.63E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Styrene	77.7	mmBtu/hr	8760	Hours	2.36E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.83E-03	8.03E-03	0%	1.83E-03	8.03E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Tetrachloroethane	77.7	mmBtu/hr	8760	Hours	2.48E-06	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.93E-04	8.44E-04	0%	1.93E-04	8.44E-04
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Toluene	77.7	mmBtu/hr	8760	Hours	4.08E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	3.17E-02	1.39E-01	0%	3.17E-02	1.39E-01
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Vinyl Chloride	77.7	mmBtu/hr	8760	Hours	1.49E-05	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.16E-03	5.07E-03	0%	1.16E-03	5.07E-03
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	Xylenes (mixed isomers)	77.7	mmBtu/hr	8760	Hours	1.84E-04	lb/mmBtu	AP-42 Table 3.2-2, Uncontrolled	1.43E-02	6.26E-02	0%		
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	Naphthalene	7.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	9.86E-04	2.47E-04	0%	9.86E-04	2.47E-04
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	Toluene	7.6	mmBtu/hr	500	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.13E-03	5.33E-04	0%	2.13E-03	5.33E-04
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	Xylenes	7.6	mmBtu/hr	500	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.46E-03	3.66E-04	0%	1.46E-03	3.66E-04
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	1,3-Butadiene	7.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	9.86E-04	2.47E-04	0%	9.86E-04	2.47E-04
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	Formaldehyde	7.6	mmBtu/hr	500	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	5.99E-04	1.50E-04	0%	5.99E-04	1.50E-04
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	Acetaldehyde	7.6	mmBtu/hr	500	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.91E-04	4.78E-05	0%	1.91E-04	4.78E-05
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	Acrolein	7.6	mmBtu/hr	500	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	5.98E-05	1.49E-05	0%	5.98E-05	1.49E-05
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	Total PAH	7.6	mmBtu/hr	500	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.61E-03	4.02E-04	0%	1.61E-03	4.02E-04
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	Naphthalene	7.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	9.86E-04	2.47E-04	0%	9.86E-04	2.47E-04
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	Toluene	7.6	mmBtu/hr	500	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.13E-03	5.33E-04	0%	2.13E-03	5.33E-04
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	Xylenes	7.6	mmBtu/hr	500	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.46E-03	3.66E-04	0%	1.46E-03	3.66E-04
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	1,3-Butadiene	7.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	9.86E-04	2.47E-04	0%	9.86E-04	2.47E-04
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	Formaldehyde	7.6	mmBtu/hr	500	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	5.99E-04	1.50E-04	0%	5.99E-04	1.50E-04
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	Acetaldehyde	7.6	mmBtu/hr	500	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.91E-04	4.78E-05	0%	1.91E-04	4.78E-05
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	Acrolein	7.6	mmBtu/hr	500	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	5.98E-05	1.49E-05	0%	5.98E-05	1.49E-05
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	Total PAH	7.6	mmBtu/hr	500	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.61E-03	4.02E-04	0%	1.61E-03	4.02E-04
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	Naphthalene	7.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	9.86E-04	2.47E-04	0%	9.86E-04	2.47E-04
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	Toluene	7.6	mmBtu/hr	500	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	2.13E-03	5.33E-04	0%	2.13E-03	5.33E-04
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	Xylenes	7.6	mmBtu/hr	500	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.46E-03	3.66E-04	0%	1.46E-03	3.66E-04
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	1,3-Butadiene	7.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	9.86E-04	2.47E-04	0%	9.86E-04	2.47E-04
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	Formaldehyde	7.6	mmBtu/hr	500	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	5.99E-04	1.50E-04	0%	5.99E-04	1.50E-04
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	Acetaldehyde	7.6	mmBtu/hr	500	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.91E-04	4.78E-05	0%	1.91E-04	4.78E-05

EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	Acrolein	7.6	mmBtu/hr	500	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	5.98E-05	1.49E-05	0%	5.98E-05	1.49E-05
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	Total PAH	7.6	mmBtu/hr	500	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.61E-03	4.02E-04	0%	1.61E-03	4.02E-04
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	Naphthalene	5.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	7.26E-04	1.82E-04	0%	7.26E-04	1.82E-04
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	Toluene	5.6	mmBtu/hr	500	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.57E-03	3.92E-04	0%	1.57E-03	3.92E-04
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	Xylenes	5.6	mmBtu/hr	500	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.08E-03	2.70E-04	0%	1.08E-03	2.70E-04
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	1,3-Butadiene	5.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	7.26E-04	1.82E-04	0%	7.26E-04	1.82E-04
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	Formaldehyde	5.6	mmBtu/hr	500	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	4.41E-04	1.10E-04	0%	4.41E-04	1.10E-04
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	Acetaldehyde	5.6	mmBtu/hr	500	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.41E-04	3.52E-05	0%	1.41E-04	3.52E-05
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	Acrolein	5.6	mmBtu/hr	500	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	4.40E-05	1.10E-05	0%	4.40E-05	1.10E-05
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	Total PAH	5.6	mmBtu/hr	500	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.18E-03	2.96E-04	0%	1.18E-03	2.96E-04
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	Naphthalene	5.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	7.26E-04	1.82E-04	0%	7.26E-04	1.82E-04
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	Toluene	5.6	mmBtu/hr	500	Hours	2.81E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.57E-03	3.92E-04	0%	1.57E-03	3.92E-04
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	Xylenes	5.6	mmBtu/hr	500	Hours	1.93E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.08E-03	2.70E-04	0%	1.08E-03	2.70E-04
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	1,3-Butadiene	5.6	mmBtu/hr	500	Hours	1.30E-04	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	7.26E-04	1.82E-04	0%	7.26E-04	1.82E-04
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	Formaldehyde	5.6	mmBtu/hr	500	Hours	7.89E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	4.41E-04	1.10E-04	0%	4.41E-04	1.10E-04
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	Acetaldehyde	5.6	mmBtu/hr	500	Hours	2.52E-05	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	1.41E-04	3.52E-05	0%	1.41E-04	3.52E-05
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	Acrolein	5.6	mmBtu/hr	500	Hours	7.88E-06	lb/mmBtu	AP-42 Table 3.4-3, Uncontrolled	4.40E-05	1.10E-05	0%	4.40E-05	1.10E-05
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	Total PAH	5.6	mmBtu/hr	500	Hours	2.12E-04	lb/mmBtu	AP-42 Table 3.4-4, Uncontrolled	1.18E-03	2.96E-04	0%	1.18E-03	2.96E-04

[1] Lb/hr for the pollutant for the worst case fuel

[2] Ton/yr for the pollutant for the worst case fuel

Xcel Blue Lake
Blue Lake Conversion Project
Emission Unit Design Information
12/16/2022

Emission Unit ID	Old Emission Unit ID	Stack ID	Old Stack ID	Unit Name	Fuel	Unique ID	Max Hourly Process Rate	Process Rate Units	Capacity Source	Mechanical Power	Units	Max Annual Utilization	Units	Comment
EQUI 1	EU 001	STRU 16	SV 001	Combustion turbine 1 (oil)	Diesel	EQUI 1Diesel	648	mmBtu/hr	Current Permit			8760	hours	
EQUI 2	EU 002	STRU 17	SV 002	Combustion turbine 2 (oil)	Diesel	EQUI 2Diesel	648	mmBtu/hr	Current Permit			8760	hours	
EQUI 3	EU 003	STRU 18	SV 003	Combustion turbine 3 (oil)	Diesel	EQUI 3Diesel	648	mmBtu/hr	Current Permit			8760	hours	
EQUI 4	EU 004	STRU 19	SV 004	Combustion turbine 4 (oil)	Diesel	EQUI 4Diesel	740	mmBtu/hr	Current Permit			8760	hours	
EQUI 5	EU 005	STRU 14	SV 005	Emergency Engine/Generator (oil)	Diesel	EQUI 5Diesel	1.1	mmBtu/hr	Current Permit			500	hours	
EQUI 7	EU 007	STRU 12	SV 007	Combustion turbine 7 (gas)	Natural Gas	EQUI 7Natural Gas	2042.4	mmBtu/hr	Current Permit			8760	hours	
EQUI 8	EU 008	STRU 13	SV 008	Combustion turbine 8 (gas)	Natural Gas	EQUI 8Natural Gas	2042.4	mmBtu/hr	Current Permit			8760	hours	
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Diesel	EQUI 23Diesel	79.6	mmBtu/hr	Manufacturer	12862	Horsepower	8760	hours	Wartsila Engine Specifications
EQUI 23	NA	STRU 24	NA	Engine Generator 1	Natural Gas	EQUI 23Natural Gas	77.7	mmBtu/hr	Manufacturer	12862	Horsepower	8760	hours	Wartsila Engine Specifications
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Diesel	EQUI 24Diesel	79.6	mmBtu/hr	Manufacturer	12862	Horsepower	8760	hours	Wartsila Engine Specifications
EQUI 24	NA	STRU 25	NA	Engine Generator 2	Natural Gas	EQUI 24Natural Gas	77.7	mmBtu/hr	Manufacturer	12862	Horsepower	8760	hours	Wartsila Engine Specifications
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Diesel	EQUI 25Diesel	79.6	mmBtu/hr	Manufacturer	12862	Horsepower	8760	hours	Wartsila Engine Specifications
EQUI 25	NA	STRU 26	NA	Engine Generator 3	Natural Gas	EQUI 25Natural Gas	77.7	mmBtu/hr	Manufacturer	12862	Horsepower	8760	hours	Wartsila Engine Specifications
EQUI 26	NA	STRU 27	NA	Emergency Generator 2	Diesel	EQUI 26Diesel	7.59	mmBtu/hr	Potential Manufacturer	1049	Horsepower	500	hours	Caterpillar Engine Specifications; see Emergency Generators tab for heat input calc.
EQUI 27	NA	STRU 28	NA	Emergency Generator 3	Diesel	EQUI 27Diesel	7.59	mmBtu/hr	Potential Manufacturer	1049	Horsepower	500	hours	Caterpillar Engine Specifications; see Emergency Generators tab for heat input calc.
EQUI 28	NA	STRU 29	NA	Emergency Generator 4	Diesel	EQUI 28Diesel	7.588	mmBtu/hr	Potential Manufacturer	1049	Horsepower	500	hours	Caterpillar Engine Specifications; see Emergency Generators tab for heat input calc.
EQUI 29	NA	STRU 30	NA	Emergency Generator 5	Diesel	EQUI 29Diesel	5.586	mmBtu/hr	Potential Manufacturer	772	Horsepower	500	hours	Caterpillar Engine Specifications; see Emergency Generators tab for heat input calc.
EQUI 43	NA	STRU 38	NA	Emergency Generator 6	Diesel	EQUI 43Diesel	5.586	mmBtu/hr	Potential Manufacturer	772	Horsepower	500	hours	Caterpillar Engine Specifications; see Emergency Generators tab for heat input calc.

Xcel Energy
Blue Lake Conversion Project
Engine Generators - Manufacturer's Data
12/16/2022

Diesel Mode

	Wartsila Emission Factors (lb/hr)	Wartsila Emission Factors (g/kWh)
CO2	N/A	N/A
NOx	10.86	0.53
CO	3.78	0.18
VOC	4.33	0.21
PM	4.53	0.22
Formaldehyde	N/A	N/A

Natural Gas Mode

	Wartsila Emission Factors (lb/hr)	Wartsila Emission Factors (g/kWh)
CO2	N/A	N/A
NOx	1.65	0.08
CO	2.51	0.12
VOC	3.26	0.16
PM	2.01	0.10
Formaldehyde	0.13	N/A

Warsilla Calculation Inputs

Mass Conversion	453.6	g/lb
Engine Rating	9370	ekW
Mech. Power	12862	bhp

MMBtu/hr gas	77.7	Data from Wartsila
MMBtu/hr oil	79.6	Data from Wartsila

Wartsila 34DF

Bore	Stroke	Displacement/cylinder		
mm	mm	liters	Cylinders	Total Displacement
340	400	36.3	20	726.3

Engine RPM	720	
NSPS NOx Limit	1.80	g/hp-hr
NSPS NOx Limit	23116.2	g/hr
NSPS NOx Limit	50.96	lb/hr

NOx limit per 40 CFR 60.4204(c)(3): 9*n^(-0.20)g/kW-hr or 6.7*n^(-0.2)g/hp-hr
Where: n = maximum engine speed and is 130 or more but less than 2000 rpm

Emissions with SU/SD/Emergency Operation

Time Startup	30	Minutes
Time Shutdown	1	Minutes

	Emission Data from Manufacturer			
	lb/startup	lb/shutdown	lb/hr startup	lb/hr shutdown
NO_x	45.00	0.20	90	12
CO	10.50	0.10	21	6
VOC as CH_4	3.22	0.10	6.44	6
PM_{10}	5.00	0.05	10	3
PM2.5 (total)	5.00	0.05	10	3

Proposed SU/SD and Emergency Operation Limits

Parameter	Value	Units
NOx SU/SD	45.20	lb/event
NOx Emergency	90	lb/hr
CO SU/SD	10.60	lb/event
CO Emergency	21	lb/hr
VOC SU/SD [1]	3.32	lb/event
VOC Emergency [1]	6.44	lb/hr
PM SU/SD	5.05	lb/event
PM Emergency	10	lb/hr

	SU/SD TPY 3 engines combined			
	NOx	CO	VOC	PM
# of Startups	700	700	700	700
Tons/yr	47.46	11.13	3.49	5.30

	SU/SD TPY Per engine			
	NOx	CO	VOC	PM
# of Shutdowns	700	700	700	700
Tons/yr	15.82	3.71	1.162	1.768

	Total Emergency Operation TPY - Per engine			
	NOx	CO	VOC	PM
Emerg. Hours	48	48	48	48
Tons/yr	2.16	0.50	0.15	0.24

	Total SU/SD/Em TPY - Per engine			
	NOx	CO	VOC	PM
Total Hours	409.67	409.67	409.67	409.67
Tons/yr	17.98	4.21	1.32	2.01

	Annual Emission Calculations (per engine)			
	NOx	CO	VOC	PM
Normal Operation Emissions on diesel (lb/hr)	10.86	3.78	4.33	4.53
Normal Operation Hours	8350	8350	8350	8350
Annual Normal Operation Emissionson diesel (tpy)	45.34	15.78	18.08	18.91
Annual SU/SD/Em Emissions (tpy)	17.98	4.21	1.32	2.01
Total annual emissions (tpy)	63.32	20.00	19.40	20.92

Short term PM10/PM2.5 PTE Calculation for Modeling

Wartsila PM lb/hr	startup lb/event	duration hours	Starts/day	PM lb/day	lb/hr w/SU lb/hr
4.53	5.00	0.5	2	114.19	4.76

Footnotes:
[1] as methane

Xcel Energy
Blue Lake Conversion Project
Combustion Turbine - Emission Calculations
12/16/2022

NOx

Max Sustained heat input	2042	MMBtu/hr
Maximum measured NOx from Turbine Stack Tests	0.036	lb/MMBtu
PTE	73.512	lb/hr

CO

Max Sustained heat input	2042	MMBtu/hr
Maximum measured CO from Turbine Stack Tests	0.019	lb/MMBtu
PTE	38.798	lb/hr

Startup Time	23	Minutes	Estimated startup and shutdown duration
Shutdown Time	11	Minutes	provided by Xcel engineers.

SU (lb/event) [1]			SD (lb/event) [2]		
NOx	**CO**	**VOC**	**NOx**	**CO**	VOC
46	122	58	22	58	28
SU (lb/hr version)			**SD (lb/hr version)**		
119	318	153	119	318	153
Emergency (lb/hr) [4]					
304	478	1040			
Emergency TPY [5]					
7.29	11.47	24.95			

SU/SDs per Year		
200	200	200

SU/SD TPY [3]		
NOx	**CO**	**VOC**
13.52	36.01	17.28

Combined Emergency TPY [5]		
NOx	**CO**	**VOC**
14.58	22.94	49.91

Combined SU/SD/Em TPY		
NOx	**CO**	**VOC**
28.10	58.96	67.19

SU/SD Emergency Total Hours		
SU/SD	**Emergency**	**Total**
113.33	48.00	161.33

SU/SD TPY [3] Per turbine		
NOx	**CO**	**VOC**
6.76	18.01	8.64

Emergency TPY [5] Per turbine		
NOx	**CO**	**VOC**
7.29	11.47	24.95

Combined SU/SD/EM TPY Per turbine		
NOx	**CO**	**VOC**
14.05	29.48	33.60

	Annual Emission Calculations (per turbine)		
	NOx	**CO**	**VOC**
Normal Operation Emissions (lb/hr)	73.51	38.80	10.03
Normal Operation Hours	8599	8599	8599
Annual Normal Operation Emissions (tpy)	316.05	166.81	43.14
Annual SU/SD/EM Emissions (TPY)	14.05	29.48	33.60
Total annual emissions (tpy)	330.10	196.28	76.73

[1] Average lb/hr from 40% to 0% load * shutdown duration; emission data from turbine manufacturer
[2] Average lb/hr from 0% to 40% load * startup duration; emission data from turbine manufacturer
[3] total emissions for 23 minute startup and 11 minute shutdown for both turbines
[4] Maximum calculated lb/hr for NOx and VOC, average for 5% - 20% load for CO
[5] 48 hours per turbine total per year; 28 hours below compliance load

Xcel Energy
Blue Lake Conversion Project
Emergency Generator Design and Emission Calculations
5/26/2024

Emergency Generator Calculations
Example 750 ekW model

Engine Specifications

Power Rating	750	ekW
Displacement	18.13	liters
Engine Speed (Standby)	1800	RPM
Mechanical Power (estimated)	1049	hp
Max fuel consumption	54.2	gallon/hr
Diesel HHV	140,000	Btu/gallon
Max heat input	7.588	MMBtu/hr
Cylinders	6	
Displacement per cylinder	3.0	liters

Calculation Constants

	1.34	hp/KW
	453.6	g/lb
	0.0034	Mmbtu/hr/KW
	0.367	Brake Specific Fuel Consumption (lb/hp-hr) [1]
	7.1	Fuel Density (lb/gallon) [1]
	0.264172	gallons per liter

NSPS Limits for Emergency Generators
kW >560, post 2006

NMHC + NOx	6.4	g/kW-hr	EPA Tier 2 Standards
CO	3.5	g/kW-hr	
PM	0.2	g/kW-hr	
PM-COND/PM-FIL ratio	0.12	AP-42 Chapter 3.4 to determine PM-COND fraction	
	0.22	g/kW-hr	
NMHC + NOx	1.05E-02	lb/hp-hr	Convert NSPS limit to convenient units
CO	5.75E-03	lb/hp-hr	Convert NSPS limit to convenient units
PM	3.29E-04	lb/hp-hr	Convert NSPS limit to convenient units

[1] From AP-42 Table 3.4-1 (10/96), footnote a.

Emergency Generator Calculations
Example 550 ekW model

Engine Specifications

Power Rating	550	ekW
Displacement	18.1	liters
Engine Speed (Standby)	1800	RPM
Mechanical Power (estimated)	772	hp
Max fuel consumption	39.9	gallon/hr
Diesel HHV	140,000	Btu/gallon
Max heat input	5.586	MMBtu/hr
Cylinders	6	
Displacement per cylinder	3.0	liters

Calculation Constants

	1.34	hp/KW
	453.6	g/lb
	0.0034	Mmbtu/hr/KW
	0.367	Brake Specific Fuel Consumption (lb/hp-hr) [1]
	7.1	Fuel Density (lb/gallon) [1]
	0.264172	gallons per liter

NSPS Limits for Emergency Generators
450 ≤ kW ≤ 560, post 2002

NMHC + NOx	6.4	g/kW-hr	EPA Tier 2 Standards
CO	3.5	g/kW-hr	
PM	0.2	g/kW-hr	
PM-COND/PM-FIL ratio	0.12		AP-42 Chapter 3.4 to determine PM-COND fraction
	0.22	g/kW-hr	
NMHC + NOx	1.05E-02	lb/hp-hr	Convert NSPS limit to convenient units
CO	5.75E-03	lb/hp-hr	Convert NSPS limit to convenient units
PM	3.29E-04	lb/hp-hr	Convert NSPS limit to convenient units

[1] From AP-42 Table 3.4-1 (10/96), footnote a.

Xcel Blue Lake
Blue Lake Conversion Project
Q/d Calculation for Rainbow Lakes Wilderness Area
12/16/2022

Pollutant	Project Emissions Turbines + Engine Generators Controlled TPY	Project Emissions Emergency Generators Controlled TPY
NOx	850.18	12.34
PM10	180.85	0.43
SO2	11.81	0.01

Pollutant	Total Project Emissions (Q) Controlled TPY	Distance (d) Kilometers	Q/d Km/tons	NOx+SO2+PM10
NOx	862.51	241.5	3.57	4.37
PM10	181.28	241.5	0.75	
SO2	11.82	241.5	0.05	

Xcel Blue Lake
Blue Lake Conversion Project
Model Conversion Factors
October 2022

Factor	Conversion
0.028766489	ton/yr to g/s
0.125997222	lb/hr to g/s
0.3048	ft to m
1.7	Volume Source TOP height
2.15	Volume Source Szinit (road Syinit) Conversion
4.3	Volume Source Syinit Conversion
10	A_{or} - is a value that conservatively estimates the conversion of SO_2 to fine particulate
100	B_{or} - is a value that conservatively estimates the conversion of NO_x to fine particulate
	Minnesota Pollution Control Agency Air Dispersion Modeling Guidance • July 2014
0.5	Release Height (mid-point)
6	Plume width
2000	lb/ton
453.59	g/lb
8760	hr/year
3600	s/hr
0.3048	ft/m

Glossary

Syinit Factor	Sigma Y initial - initial lateral dimension for dispersion model
Szinit Factor	Sigam Z initial - vertical dimension for dispersion model
TOP	Top of plume height - see modeling protocol for more information

State	County	Metric	Precursor	Emissions (tpy)	Stack		MERP[1]	MaxConc	Conc Units	Modeled Source Description
Minnesota	Dakota	8-hr Ozone	NOx		500	10	4718	0.105977938	ppb	10 meter stack; 500 TPY
Minnesota	Dakota	8-hr Ozone	VOC		500	10	5165	0.096805334	ppb	10 meter stack; 500 TPY
Minnesota	Dakota	Annual PM2.5	NOx		500	10	29620	0.003376103	ug/m3	10 meter stack; 500 TPY
Minnesota	Dakota	Annual PM2.5	SO2		500	10	7966	0.012553342	ug/m3	10 meter stack; 500 TPY
Minnesota	Dakota	Daily PM2.5	NOx		500	10	11193	0.053605557	ug/m3	10 meter stack; 500 TPY
Minnesota	Dakota	Daily PM2.5	SO2		500	10	1511	0.397210836	ug/m3	10 meter stack; 500 TPY

[1] MERP Values downloaded from EPA SCRAM MERP Qlik View

Table 4-1. Lowest, median, and highest illustrative MERP values (tons per year) by precursor, pollutant and climate zone.

Note: illustrative MERP values are derived based on EPA modeling and EPA recommended SILs from EPA's final SILs guidance (U.S. Environmental Protection Agency, 2018).

	8-hr O_3 from NO_X			8-hr O_3 from VOC		
Climate Zone	Lowest	Median	Highest	Lowest	Median	Highest
Northeast	209	495	5,773	2,068	3,887	15,616
Southeast	170	272	659	1,936	7,896	42,964
Ohio Valley	126	340	1,346	1,159	3,802	13,595
Upper Midwest	125	362	4,775	1,560	2,153	30,857
Rockies/Plains	184	400	3,860	1,067	2,425	12,788
South	190	417	1,075	2,307	4,759	30,381
Southwest	204	422	1,179	1,097	10,030	144,744
West	218	429	936	1,094	1,681	17,086
Northwest	199	373	4,031	1,049	2,399	15,929

	Daily PM2.5 from NO_X			Daily PM2.5 from SO_2		
Climate Zone	Lowest	Median	Highest	Lowest	Median	Highest
Northeast	2,218	15,080	34,307	623	3,955	8,994
Southeast	1,943	8,233	23,043	367	2,475	5,685
Ohio Valley	2,570	10,119	32,257	348	3,070	16,463
Upper Midwest	2,963	10,043	29,547	454	2,482	6,096
Rockies/Plains	1,740	9,389	31,263	251	2,587	19,208
South	1,881	8,079	24,521	274	1,511	10,112
Southwest	6,514	26,322	101,456	1,508	8,730	27,219
West	1,073	8,570	34,279	188	2,236	24,596
Northwest	3,003	11,943	20,716	1,203	3,319	8,418

	Annual PM2.5 from NO_X			Annual PM2.5 from SO_2		
Climate Zone	Lowest	Median	Highest	Lowest	Median	Highest
Northeast	10,142	47,396	137,596	4,014	21,353	41,231
Southeast	5,679	45,076	137,516	859	14,447	25,433
Ohio Valley	7,625	31,931	150,868	3,098	23,420	58,355
Upper Midwest	10,011	33,497	139,184	2,522	17,997	45,113
Rockies/Plains	9,220	39,819	203,546	2,263	16,939	106,147
South	7,453	41,577	110,478	1,781	11,890	58,612
Southwest	11,960	128,564	779,117	10,884	38,937	105,417
West	3,182	29,779	103,000	2,331	11,977	66,773
Northwest	7,942	21,928	71,569	11,276	15,507	18,263

Xcel Blue Lake
Blue Lake Conversion Project
Ozone and PM2.5 Precursor Evaluation
October 2022

Metric	Precursor	Project Emissions (tpy)	MERP	MaxConc	Conc Units	MERP Calculation
8-hr Ozone	NOx	863.72	4718	0.10598	ppb	0.18307
8-hr Ozone	VOC	212.51	5165	0.09681	ppb	0.04114
Annual PM2.5	NOx	863.72	29620	0.00338	ug/m^3	0.02916
Annual PM2.5	SO2	11.90	7966	0.01255	ug/m^3	0.00149
Daily PM2.5	NOx	863.72	11193	0.05361	ug/m^3	0.07717
Daily PM2.5	SO2	11.90	1511	0.39721	ug/m^3	0.00788
SIL Results	**Direct Pollutant**	**Project Emissions (tpy)**	**SIL**	**MaxConc**	**Conc Units**	**Percent of SIL**
24-hour	PM2.5	62.52	1.2	3.26	ug/m^3	2.71438
Annual	PM2.5	62.76	0.2	0.28	ug/m^3	1.38100

Tier 1 (MERP) Significant Impact Level Comparison

Conversion Project Impacts	% of SIL	Analysis Complete?
8-hour Ozone	22%	YES
24-hour PM2.5	280%	NO
Annual PM2.5	141%	NO

NAAQS Secondary Formation Accounting	Concentration (μg/m^3)	Project Secondary Contribution	Total Background (ug/m^3)
24-hour PM2.5 Background	18.07	0.08504	18.15
Annual PM2.5 Background	6.30	0.03065	6.33

Increment Accounting	Emission Rate (lb/hr)	Project Source Total Increment Emission Rate (tpy)	MERP		Critical AQ Threshold		AQI Impact (μg/m^3)	
Pollutant			Annual	Daily	Annual	Daily	Annual	Daily
NOX	179.60	850.18	29620	11193	0.2	1.2	0.00574	0.08434
SO2	2.70	11.81	7966	1511	0.2	1.2	0.00030	0.00938

MINNESOTA POLLUTION CONTROL AGENCY
520 Lafayette Road North
St. Paul, MN 55155-4194

AQDM-02

Air Quality Dispersion Modeling (AQDM) protocol spreadsheet

(Previously AQDMPS-01)

Doc Type: Air Dispersion Modeling

Note: Permit applicants may create their own spreadsheet tabs.

AQ Facility ID number:	13900010
Facility name:	Xcel Energy - Blue Lake
Facility address:	1200 70th Street S Shakopee, MN 55379-2100
Facility contact:	Michael Aasen

Emission Calculations Table

Permit ID	AERMOD ID	Emission unit	Pollutant	Operating scenario #	Operating scenario Description	Description	Throughput	Throughput units	Emission factor	Emission factor units	Emission factors references/Assumptions/Equations
STRU 12	STRU012		NOX	1-hour	Natural Gas	Combustion turbine 7 (gas)	2042.4	mmBtu/hr	73.51	lb/hr	Permit 13900010-104
STRU 13	STRU013		NOX	1-hour	Natural Gas	Combustion turbine 8 (gas)	2042.4	mmBtu/hr	73.51	lb/hr	Permit 13900010-104
STRU 24	STRU021		NOX	1-hour	Diesel	Engine Generator 1	79.6	mmBtu/hr	10.86	lb/hr	BACT Engine Specifications
STRU 25	STRU022		NOX	1-hour	Diesel	Engine Generator 2	79.6	mmBtu/hr	10.86	lb/hr	BACT Engine Specifications
STRU 26	STRU023		NOX	1-hour	Diesel	Engine Generator 3	79.6	mmBtu/hr	10.86	lb/hr	BACT Engine Specifications
STRU 24	STRU021		NOX	Annual	Diesel	Engine Generator 1	79.6	mmBtu/hr	14.46	lb/hr	BACT Engine Specifications
STRU 25	STRU022		NOX	Annual	Diesel	Engine Generator 2	79.6	mmBtu/hr	14.46	lb/hr	BACT Engine Specifications
STRU 26	STRU023		NOX	Annual	Diesel	Engine Generator 3	79.6	mmBtu/hr	14.46	lb/hr	BACT Engine Specifications
STRU 12	STRU012		PM2.5	24-hour; Annual	Natural Gas	Combustion turbine 7 (gas)	2042.4	mmBtu/hr	0.007	lb/mmBtu	Manufacturer (front half filterable); Assumed equal to PM10
STRU 13	STRU013		PM2.5	24-hour; Annual	Natural Gas	Combustion turbine 8 (gas)	2042.4	mmBtu/hr	0.007	lb/mmBtu	Manufacturer (front half filterable); Assumed equal to PM10
STRU 24	STRU021		PM2.5	24-hour	Diesel	Engine Generator 1	79.6	mmBtu/hr	4.758	lb/hr	BACT Engine Specifications
STRU 25	STRU022		PM2.5	24-hour	Diesel	Engine Generator 2	79.6	mmBtu/hr	4.758	lb/hr	BACT Engine Specifications
STRU 26	STRU023		PM2.5	24-hour	Diesel	Engine Generator 3	79.6	mmBtu/hr	4.758	lb/hr	BACT Engine Specifications
STRU 24	STRU021		PM2.5	Annual	Diesel	Engine Generator 1	79.6	mmBtu/hr	4.777	lb/hr	BACT Engine Specifications
STRU 25	STRU022		PM2.5	Annual	Diesel	Engine Generator 2	79.6	mmBtu/hr	4.777	lb/hr	BACT Engine Specifications
STRU 26	STRU023		PM2.5	Annual	Diesel	Engine Generator 3	79.6	mmBtu/hr	4.777	lb/hr	BACT Engine Specifications
STRU 24	STRU021		CO	1 hour, 8 hour	Diesel	Engine Generator 1	79.6	mmBtu/hr	3.78	lb/hr	BACT Engine Specifications
STRU 25	STRU022		CO	1 hour, 8 hour	Diesel	Engine Generator 2	79.6	mmBtu/hr	3.78	lb/hr	BACT Engine Specifications
STRU 26	STRU023		CO	1 hour, 8 hour	Diesel	Engine Generator 3	79.6	mmBtu/hr	3.78	lb/hr	BACT Engine Specifications
STRU 24	STRU021		PM10	24-hour	Diesel	Engine Generator 1	79.6	mmBtu/hr	4.758	lb/hr	BACT Engine Specifications
STRU 25	STRU022		PM10	24-hour	Diesel	Engine Generator 2	79.6	mmBtu/hr	4.758	lb/hr	BACT Engine Specifications
STRU 26	STRU023		PM10	24-hour	Diesel	Engine Generator 3	79.6	mmBtu/hr	4.758	lb/hr	BACT Engine Specifications
STRU 24	STRU021		PM10	Annual	Diesel	Engine Generator 1	79.6	mmBtu/hr	4.777	lb/hr	BACT Engine Specifications
STRU 25	STRU022		PM10	Annual	Diesel	Engine Generator 2	79.6	mmBtu/hr	4.777	lb/hr	BACT Engine Specifications
STRU 26	STRU023		PM10	Annual	Diesel	Engine Generator 3	79.6	mmBtu/hr	4.777	lb/hr	BACT Engine Specifications

Xcel Blue Lake
Blue Lake Conversion Project
Paved Road PM10 and PM2.5 Calculations
October 2022

Description	Throughput		Pollutant	Emission Factor	Source	Uncontrolled Emissions lb/hr	Uncontrolled Emissions tons/year	Control	Controlled Emissions lb/hr	Controlled Emissions tons/year	Hourly g/s	Annual g/s
Paved Road-Fuel Truck	0.415	VMT/hr	PM	0.6979 lb/VMT	[1]	0.290	0.033	0%	0.290	0.033	0.036	0.00095
	94.38	VMT/yr	PM10	0.1396 lb/VMT		0.058	0.007	0%	0.058	0.007	0.007	0.00019
			PM2.5	0.0343 lb/VMT		0.014	0.002	0%	0.014	0.002	0.002	0.00005

[1] AP-42, 5th Ed., Vol I (1/2011), Section 13.2.1 'Paved Roads'. E (lb/vehicle mile traveled) =k * (sL)^0.91*(W)^1.02

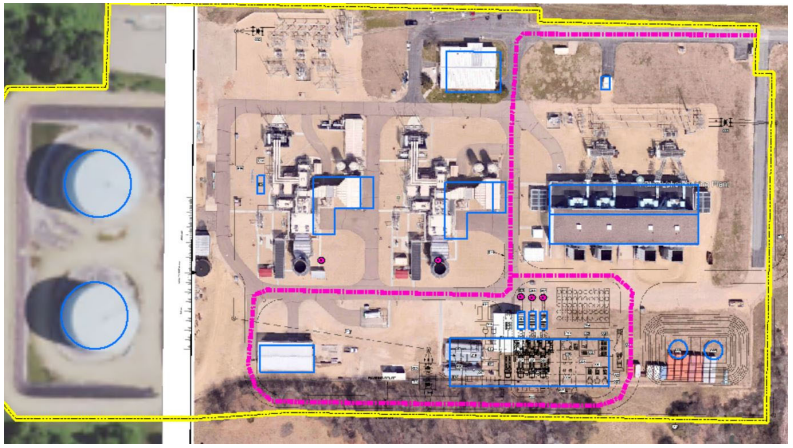
Road Surface Silt Loading, sL (g/m^2): 2.4 See Silt Load Reference Tab

Particle Size Multiplier, k (lb/VMT): 0.011 for PM
0.0022 for PM10
0.00054 for PM2.5

Control Efficiency for water/sweeping: 0%

Truck Type	Round Trip Distance (miles) [a]	Max Hourly Usage Rate (lb/hr)	Vehicle Empty Weight (ton)	Vehicle Loaded Weight (ton)	Average Vehicle Weight (ton)	Max Trips per Hour	Max Trips per Year [b]	VMT per Hour [c]	VMT per Year
Fuel Delivery	0.415	--	13.6	40	26.78		227.43	0.415	94.38

[a] Distances measured as round trip from gate, to fuel tanks, and back to gate. (See pink dotted route on image.)
[b] Assume 1,000 hours operating on ULSD for each engine, results in 227 trucks a year for fuel delivery.
[c] For fuel delivery, assumes no more than 1 truck delivering fuel in a single hour.
**Routine operations to maintain fuel stability when not dispatched on ULSD during the year to prevent buildup requiring operational maintenance is burning 10% of the fuel



80	MMBtu/hr
79,600,000	Btu/hr
140,000	Btu/gallon
569	gallons/hr
1,000	hours/year
568,571	gallons/year
1,705,714	total (3 engines)
7500	tanker capacity
227.43	trips/year

Xcel Blue Lake
Blue Lake Conversion Project
Paved Road Silt Load Reference
October 2022

AP-42 Section 13.2.1 Paved Roads

The Xcel Blue Lake paved road conservatively assumes the wintertime baseline silt loading of 2.4 g/m^2 for the entire year for a low volume road.

Table 13.2.1-2 presents recommended default silt loadings for normal baseline conditions and for wintertime baseline conditions in areas that experience frozen precipitation with periodic application of antiskid material[24]. The winter baseline is represented as a multiple of the non-winter baseline, depending on the ADT value for the road in question. As shown, a multiplier of 4 is applied for low volume roads (< 500 ADT) to obtain a wintertime baseline silt loading of 4 X 0.6 = 2.4 g/m^2.

Table 13.2.1-2. Ubiquitous Silt Loading Default Values with Hot Spot Contributions from Anti-Skid Abrasives (g/m^2)

ADT Category	< 500	500-5,000	5,000-10,000	> 10,000
Ubiquitous Baseline g/m^2	0.6	0.2	0.06	0.03 0.015 limited access
Ubiquitous Winter Baseline Multiplier during months with frozen precipitation	X4	X3	X2	X1
Initial peak additive contribution from application of antiskid abrasive (g/m^2)	2	2	2	2
Days to return to baseline conditions (assume linear decay)	7	3	1	0.5

Xcel Blue Lake
Blue Lake Conversion Project
Preliminary Stack Parameters
October 2022

Stack ID	Old Stack ID	MODELID	Operators Description	Height of Opening From Ground (feet)	Inside Dimensions		Design Flow Rate at Top (ACFM)	Exit Gas Temperature at Top (F)	Flow Rate/ Temperature Information Source	Discharge Direction	Height of Opening From Ground (m)	Inside Dimensions		Exit Gas Temperature at Top (K)	Exit Velocity (m/sec)	Exit Velocity (ft/sec)
					Diameter or Length (feet)	Width (feet)						Diameter or Length (m)	Width (m)			
STRU 16	SV 001		Combustion turbine 1 (oil) Stack	52	15.3	15.3	1360000	852		Up, No Cap	15.85	4.66	4.66	728.71	29.513	96.829
STRU 17	SV 002		Combustion turbine 2 (oil) Stack	52	15.3	15.3	1360000	852		Up, No Cap	15.85	4.66	4.66	728.71	29.513	96.829
STRU 18	SV 003		Combustion turbine 3 (oil) Stack	52	15.3	15.3	1360000	852		Up, No Cap	15.85	4.66	4.66	728.71	29.513	96.829
STRU 19	SV 004		Combustion turbine 4 (oil) Stack	52	15.3	15.3	1360000	950		Up, No Cap	15.85	4.66	4.66	783.15	29.513	96.829
STRU 12	SV 007		Combustion turbine 7 (gas) Stack	50	17.7		2388000	1105		Up, No Cap	15.24	5.39		869.26	49.302	161.751
STRU 13	SV 008		Combustion turbine 8 (gas) Stack	50	17.7		2388000	1105		Up, No Cap	15.24	5.39		869.26	49.302	161.751
STRU 24	NA		New Engine Generator 1 (DF) Stack	95	4		68281	629	Wartsila - on oil	Up, No Cap	28.96	1.22		604.82	27.603	90.560
STRU 25	NA		New Engine Generator 2 (DF) Stack	95	4		68281	629	Wartsila - on oil	Up, No Cap	28.96	1.22		604.82	27.603	90.560
STRU 26	NA		New Engine Generator 3 (DF) Stack	95	4		68281	629	Wartsila - on oil	Up, No Cap	28.96	1.22		604.82	27.603	90.560
			New Engine Generator 1 (DF) Stack		4		58703	708.4	Wartsila - on gas							
			New Engine Generator 2 (DF) Stack		4		58703	708.4	Wartsila - on gas							
			New Engine Generator 3 (DF) Stack		4		58703	708.4	Wartsila - on gas							

MINNESOTA POLLUTION CONTROL AGENCY
520 Lafayette Road North
St. Paul, MN 55155-4194

AQDM-02

Air Quality Dispersion Modeling (AQDM) protocol spreadsheet

(Previously AQDMPS-01)

Doc Type: Air Dispersion Modeling

Note: Permit applicants may create their own spreadsheet tabs.

AQ Facility ID number:	13900010
Facility name:	Xcel Energy - Blue Lake
Facility address:	1200 70th Street S Shakopee, MN 55379-2100
Facility contact:	Michael Aasen

							Easting	Northing									
Permit	AERMOD	Pollutant	Averaging Time	Operating scenario	Scalar/Variable emissions_type	Release_Type	X1	Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	Exit_Temp	Exit_Vel	Diam	Flow rate	Description
ID	ID			#			[m]	[m]	[m]	[lb/hr]	[g/sec]	[m]	[K]	[m/s]	[m]	[ACFM]	
STRU 12	STRU012	NOX	1-HOUR	8,760 hours/year; natural gas		POINT	465,895.000	4,959,202.000	229.6	73.51	9.26E+00	15.24	869.26	49.30	5.39	2,388,000	Combustion Turbine #7 - 174 MW
STRU 13	STRU013	NOX	1-HOUR	8,760 hours/year; natural gas		POINT	465,841.000	4,959,202.000	229.6	73.51	9.26E+00	15.24	869.26	49.30	5.39	2,388,000	Combustion Turbine #8 - 174 MW
STRU 24	STRU021	NOX	1-HOUR	8,760 hours/year; fuel oil		POINT	465,933.262	4,959,185.123	229.53	10.86	1.368	28.956	604.82	27.60	1.22	68,281	New Wartsila Engine 1 of 3 (West)
STRU 25	STRU022	NOX	1-HOUR	8,760 hours/year; fuel oil		POINT	465,938.382	4,959,185.083	229.5	10.86	1.368	28.956	604.82	27.60	1.22	68,281	New Wartsila Engine 2 of 3 (Central)
STRU 26	STRU023	NOX	1-HOUR	8,760 hours/year; fuel oil		POINT	465,943.581	4,959,184.964	229.47	10.86	1.368	28.956	604.82	27.60	1.22	68,281	New Wartsila Engine 3 of 3 (East)
STRU 24	STRU021	NOX	ANNUAL	8,760 hours/year; fuel oil		POINT	465,933.262	4,959,185.123	229.53	14.46	1.822	28.956	604.82	27.60	1.22	68,281	New Wartsila Engine 1 of 3 (West)
STRU 25	STRU022	NOX	ANNUAL	8,760 hours/year; fuel oil		POINT	465,938.382	4,959,185.083	229.5	14.46	1.822	28.956	604.82	27.60	1.22	68,281	New Wartsila Engine 2 of 3 (Central)
STRU 26	STRU023	NOX	ANNUAL	8,760 hours/year; fuel oil		POINT	465,943.581	4,959,184.964	229.47	14.46	1.822	28.956	604.82	27.60	1.22	68,281	New Wartsila Engine 3 of 3 (East)
STRU 12	STRU012	PM2.5	24-HOUR/ ANNUAL	8,760 hours/year; natural gas		POINT	465,895.000	4,959,202.000	229.600	13.48	1.70E+00	15.24	869.26	49.30	5.39	2,388,000.000	Combustion Turbine #7 - 174 MW
STRU 13	STRU013	PM2.5	24-HOUR/ ANNUAL	8,760 hours/year; natural gas		POINT	465,841.000	4,959,202.000	229.600	13.48	1.70E+00	15.24	869.26	49.30	5.39	2,388,000.000	Combustion Turbine #8 - 174 MW
STRU 24	STRU021	PM2.5	24-HOUR	8,760 hours/year; fuel oil		POINT	465,933.262	4,959,185.123	229.530	4.76	5.99E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 1 of 3 (West)
STRU 25	STRU022	PM2.5	24-HOUR	8,760 hours/year; fuel oil		POINT	465,938.382	4,959,185.083	229.500	4.76	5.99E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 2 of 3 (Central)
STRU 26	STRU023	PM2.5	24-HOUR	8,760 hours/year; fuel oil		POINT	465,943.581	4,959,184.964	229.470	4.76	5.99E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 3 of 3 (East)
STRU 24	STRU021	PM2.5	ANNUAL	8,760 hours/year; fuel oil		POINT	465,933.262	4,959,185.123	229.530	4.78	6.02E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 1 of 3 (West)
STRU 25	STRU022	PM2.5	ANNUAL	8,760 hours/year; fuel oil		POINT	465,938.382	4,959,185.083	229.500	4.78	6.02E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 2 of 3 (Central)
STRU 26	STRU023	PM2.5	ANNUAL	8,760 hours/year; fuel oil		POINT	465,943.581	4,959,184.964	229.470	4.78	6.02E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 3 of 3 (East)
STRU 24	STRU021	CO	1-HOUR, 8-HOUR	8,760 hours/year; fuel oil		POINT	465,933.262	4,959,185.123	229.53	3.78	4.76E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 1 of 3 (West)
STRU 25	STRU022	CO	1-HOUR, 8-HOUR	8,760 hours/year; fuel oil		POINT	465,938.382	4,959,185.083	229.5	3.78	4.76E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 2 of 3 (Central)
STRU 26	STRU023	CO	1-HOUR, 8-HOUR	8,760 hours/year; fuel oil		POINT	465,943.581	4,959,184.964	229.47	3.78	4.76E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 3 of 3 (East)
STRU 24	STRU021	PM10	24-HOUR	8,760 hours/year; fuel oil		POINT	465,933.262	4,959,185.123	229.530	4.76	5.99E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 1 of 3 (West)
STRU 25	STRU022	PM10	24-HOUR	8,760 hours/year; fuel oil		POINT	465,938.382	4,959,185.083	229.500	4.76	5.99E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 2 of 3 (Central)
STRU 26	STRU023	PM10	24-HOUR	8,760 hours/year; fuel oil		POINT	465,943.581	4,959,184.964	229.470	4.76	5.99E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 3 of 3 (East)
STRU 24	STRU012	PM10	ANNUAL	8,760 hours/year; fuel oil		POINT	465,933.262	4,959,185.123	229.530	4.78	6.02E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 1 of 3 (West)
STRU 25	STRU013	PM10	ANNUAL	8,760 hours/year; fuel oil		POINT	465,938.382	4,959,185.083	229.500	4.78	6.02E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 2 of 3 (Central)
STRU 26	STRU021	PM10	ANNUAL	8,760 hours/year; fuel oil		POINT	465,943.581	4,959,184.964	229.470	4.78	6.02E-01	28.956	604.82	27.60	1.22	68,281.000	New Wartsila Engine 3 of 3 (East)

Xcel Blue Lake
Blue Lake Conversion Project
NAAQS Nearby Source Emissions
October 2022

ID	Pollutant	Averaging time	Source Type	X1	Y1	Emission_Rate (lb/hr)	Emission_Rate (g/s)	Description	Permit ID
AGCSV001	NOX	1-hour	Point	462929.93	4,960,616.300	8.07E+01	1.02E+01	Nearby Source - Anchor Glass	EU001
AGCSV003	NOX	1-hour	Point	462918.81	4,960,581.540	8.16E+01	1.03E+01	Nearby Source - Anchor Glass	EU002
AGCSV701	NOX	1-hour	Point	462979.12	4,960,617.580	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV702	NOX	1-hour	Point	462977.62	4,960,612.320	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV703	NOX	1-hour	Point	462976.01	4,960,606.740	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV704	NOX	1-hour	Point	462974.29	4,960,601.050	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV705	NOX	1-hour	Point	462972.68	4,960,595.370	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV706	NOX	1-hour	Point	462970.96	4,960,589.140	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV707	NOX	1-hour	Point	462969.14	4,960,583.020	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV708	NOX	1-hour	Point	462967.53	4,960,577.550	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV709	NOX	1-hour	Point	462965.81	4,960,571.330	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV710	NOX	1-hour	Point	462964.1	4,960,565.640	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV711	NOX	1-hour	Point	462962.92	4,960,560.910	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCSV712	NOX	1-hour	Point	462961.31	4,960,555.760	1.96E-01	2.47E-02	Nearby Source - Anchor Glass	EU016-EU021
AGCEQUI30	NOX	1-hour	Volume	463,218.000	4,960,435.000	3.43E-01	4.32E-02	Nearby Source - Anchor Glass	EQUI30
AGCEQUI31	NOX	1-hour	Volume	463,040.000	4,960,462.000	5.34E-01	6.73E-02	Nearby Source - Anchor Glass	EQUI31
KESST010	NOX	1-hour	Point	457447.17	4,960,367.140	7.71E+01	9.71E+00	Nearby Source - Koda Energy	EQUI73 (SCREENED OUT VIA SIL)
KESVL001	NOX	1-hour	Volume	457,406.200	4,960,362.500	1.10E-01	1.39E-02	Nearby Source - Koda Energy	No EQUI in Permit (SCREENED OUT VIA SIL)
KESVL002	NOX	1-hour	Volume	457,414.500	4,960,348.000	9.00E-02	1.13E-02	Nearby Source - Koda Energy	No EQUI in Permit (SCREENED OUT VIA SIL)

ID	Pollutant	Averaging time	Source Type	X1	Y1	Emission_Rate (lb/hr)	Emission_Rate (g/s)	Description	Permit ID
CTCSV004	PM2.5	24-hr; Annual	Point	462072.8	4,960,751.600	7.86E+00	9.90E-01	Nearby Source - CertainTeed	EU012; EU043
CTCSV005	PM2.5	24-hr; Annual	Point	462059	4,960,715.500	4.60E-02	5.80E-03	Nearby Source - CertainTeed	EU008
CTCSV006	PM2.5	24-hr; Annual	Point	462059.1	4,960,721.500	7.39E-02	9.31E-03	Nearby Source - CertainTeed	EU009
CTCSV007	PM2.5	24-hr; Annual	Point	462059.1	4,960,727.600	7.39E-02	9.31E-03	Nearby Source - CertainTeed	EU010
CTCSV008	PM2.5	24-hr; Annual	Point	462080.3	4,960,710.900	1.02E-01	1.28E-02	Nearby Source - CertainTeed	EU013
CTCSV013	PM2.5	24-hr; Annual	Point	462031.1	4,960,683.200	2.48E-01	3.12E-02	Nearby Source - CertainTeed	EU011; EU023
CTCSV014	PM2.5	24-hr; Annual	Point	462034.3	4,960,668.900	7.06E-02	8.90E-03	Nearby Source - CertainTeed	EU015
CTCSV019	PM2.5	24-hr; Annual	Point	462041.4	4,960,696.500	2.48E-01	3.12E-02	Nearby Source - CertainTeed	EU012; EU025
CTCSV020	PM2.5	24-hr; Annual	Point	462039.6	4,960,694.700	3.86E-02	4.86E-03	Nearby Source - CertainTeed	EU026
CTCSV022	PM2.5	24-hr; Annual	Point	462048	4,960,697.900	1.54E-01	1.94E-02	Nearby Source - CertainTeed	EU028
CTCSV040	PM2.5	24-hr; Annual	Point	462033.5	4,960,634.100	3.25E-01	4.10E-02	Nearby Source - CertainTeed	EU047
CTCSV041	PM2.5	24-hr; Annual	Point	462033.6	4,960,640.900	3.25E-01	4.10E-02	Nearby Source - CertainTeed	EU048
CTCSV044	PM2.5	24-hr; Annual	Point	462048.9	4,960,658.600	2.54E+00	3.20E-01	Nearby Source - CertainTeed	EU050; EU052; EU074; EU081-86
CTCSV051	PM2.5	24-hr; Annual	Point	462034.5	4,960,661.500	2.78E+00	3.50E-01	Nearby Source - CertainTeed	EU070; EU079; EU088
CTCSV052	PM2.5	24-hr; Annual	Point	462032	4,960,661.500	2.22E+00	2.80E-01	Nearby Source - CertainTeed	EU070; EU080; EU088
CTCSV053	PM2.5	24-hr; Annual	Point	462048.9	4,960,644.700	2.10E-01	2.64E-02	Nearby Source - CertainTeed	EU013; EU014
CTCSV056	PM2.5	24-hr; Annual	Point	462059	4,960,733.000	7.39E-02	9.31E-03	Nearby Source - CertainTeed	EU087
CTCSV057	PM2.5	24-hr; Annual	Point	462124.8	4,960,712.900	1.27E+00	1.60E-01	Nearby Source - CertainTeed	EU090
CTCSV058	PM2.5	24-hr; Annual	Point	462074.2	4,960,817.100	9.52E-01	1.20E-01	Nearby Source - CertainTeed	EU091-093
CTCSV060	PM2.5	24-hr; Annual	Point	462030.7	4,960,697.500	6.60E-01	8.32E-02	Nearby Source - CertainTeed	EU070; EU094
CTCSV061	PM2.5	24-hr; Annual	Point	462034.6	4,960,697.500	9.52E-01	1.20E-01	Nearby Source - CertainTeed	EU070; EU095
CTCSV062	PM2.5	24-hr; Annual	Point	462021.2	4,960,661.500	1.11E+00	1.40E-01	Nearby Source - CertainTeed	EU070; EU096
CTCSV063	PM2.5	24-hr; Annual	Point	462024.8	4,960,661.500	1.67E+00	2.10E-01	Nearby Source - CertainTeed	EU070; EU097
CTCSV064	PM2.5	24-hr; Annual	Point	462028.4	4,960,661.500	8.73E-01	1.10E-01	Nearby Source - CertainTeed	EU070; EU098
CTCSV065	PM2.5	24-hr; Annual	Point	462096.2	4,960,722.600	6.71E-01	8.45E-02	Nearby Source - CertainTeed	EU099; EU100
CTCSV066	PM2.5	24-hr; Annual	Point	462092.2	4,960,762.400	2.44E-01	3.07E-02	Nearby Source - CertainTeed	NOT IN CURRENT PERMIT
CTCSV069	PM2.5	24-hr; Annual	Point	462120.4	4,960,826.900	6.11E-02	7.70E-03	Nearby Source - CertainTeed	NOT IN CURRENT PERMIT
CTCSV017	PM2.5	24-hr; Annual	Point	462044	4,960,729.800	2.06E-01	2.59E-02	Nearby Source - CertainTeed	EU020
CTCSV042	PM2.5	24-hr; Annual	Point	462045.8	4,960,672.500	2.32E-01	2.92E-02	Nearby Source - CertainTeed	EU049
CTCSV043	PM2.5	24-hr; Annual	Point	462039.1	4,960,663.500	3.00E-02	3.78E-03	Nearby Source - CertainTeed	EU051
CTCSV045	PM2.5	24-hr; Annual	Point	462047.6	4,960,665.900	5.91E-01	7.45E-02	Nearby Source - CertainTeed	EU053
CTCSV046	PM2.5	24-hr; Annual	Point	462048.7	4,960,689.400	2.32E-01	2.92E-02	Nearby Source - CertainTeed	EU024
CTCSV047	PM2.5	24-hr; Annual	Point	462038	4,960,682.600	2.46E+00	3.10E-01	Nearby Source - CertainTeed	EU070; EU075
CTCSV048	PM2.5	24-hr; Annual	Point	462019.4	4,960,697.400	1.98E+00	2.50E-01	Nearby Source - CertainTeed	EU070; EU076; EU088

ID	Pollutant	Averaging time	Source Type	X1	Y1	Emission_Rate (lb/hr)	Emission_Rate (g/s)	Description	Permit ID
CTCSV049	PM2.5	24-hr; Annual	Point	462037.9	4,960,697.500	1.59E+00	2.00E-01	Nearby Source - CertainTeed	EU070; EU077; EU088
CTCSV050	PM2.5	24-hr; Annual	Point	462035	4,960,697.400	1.27E+00	1.60E-01	Nearby Source - CertainTeed	EU070; EU078; EU088
CTCSV011	PM2.5	24-hr; Annual	Point	462027.55	4,960,686.020	1.00E-01	1.26E-02	Nearby Source - CertainTeed	EU021
CTCSV018	PM2.5	24-hr; Annual	Point	462038.24	4,960,685.270	4.00E-02	5.04E-03	Nearby Source - CertainTeed	EU020

ID	Pollutant	Averaging time	Source Type	X1	Y1	Emission_Rate (lb/hr)	Emission_Rate (g/s)	Description	Permit ID
AGCSV001	PM2.5	24-hr; Annual	Point	462,929.930	4,960,616.300	1.33E+01	1.68E+00	Nearby Source - Anchor Glass	EU001
AGCSV003	PM2.5	24-hr; Annual	Point	462,918.810	4,960,581.540	1.35E+01	1.70E+00	Nearby Source - Anchor Glass	EU002
AGCSV701	PM2.5	24-hr; Annual	Point	462,979.120	4,960,617.580	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV702	PM2.5	24-hr; Annual	Point	462,977.620	4,960,612.320	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV703	PM2.5	24-hr; Annual	Point	462,976.010	4,960,606.740	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV704	PM2.5	24-hr; Annual	Point	462,974.290	4,960,601.050	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV705	PM2.5	24-hr; Annual	Point	462,972.680	4,960,595.370	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV706	PM2.5	24-hr; Annual	Point	462,970.960	4,960,589.140	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV707	PM2.5	24-hr; Annual	Point	462,969.140	4,960,583.020	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV708	PM2.5	24-hr; Annual	Point	462,967.530	4,960,577.550	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV709	PM2.5	24-hr; Annual	Point	462,965.810	4,960,571.330	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV710	PM2.5	24-hr; Annual	Point	462,964.100	4,960,565.640	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV711	PM2.5	24-hr; Annual	Point	462,962.920	4,960,560.910	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV712	PM2.5	24-hr; Annual	Point	462,961.310	4,960,555.760	5.51E-01	6.94E-02	Nearby Source - Anchor Glass	EU009-12; EU014-EU015; EU016-EU021
AGCSV005	PM2.5	24-hr; Annual	Point	462,926.280	4,960,559.650	3.83E-01	4.83E-02	Nearby Source - Anchor Glass	EU003, EU005
AGCSV006	PM2.5	24-hr; Annual	Point	462,932.980	4,960,613.490	4.80E-01	6.05E-02	Nearby Source - Anchor Glass	EU006
AGCSV008	PM2.5	24-hr; Annual	Point	462,992.630	4,960,534.550	6.86E-01	8.64E-02	Nearby Source - Anchor Glass	EU024
AGCSV009	PM2.5	24-hr; Annual	Point	462,916.060	4,960,565.500	3.83E-01	4.83E-02	Nearby Source - Anchor Glass	EU004
AGCCT1	PM2.5	24-hr; Annual	Point	462,883.890	4,960,628.500	1.70E-02	2.14E-03	Nearby Source - Anchor Glass	IA
AGCCT2	PM2.5	24-hr; Annual	Point	462,887.590	4,960,627.280	1.70E-02	2.14E-03	Nearby Source - Anchor Glass	IA
AGCEQUI30	PM2.5	24-hr; Annual	Volume	463,218.000	4,960,435.000	2.60E-02	3.28E-03	Nearby Source - Anchor Glass	EQUI30
AGCEQUI31	PM2.5	24-hr; Annual	Volume	463,040.000	4,960,462.000	4.10E-02	5.17E-03	Nearby Source - Anchor Glass	EQUI31
AGCEU013	PM2.5	24-hr; Annual	Volume	462,962.000	4,960,543.000	4.35E-02	5.48E-03	Nearby Source - Anchor Glass	EU013
AGCEU003	PM2.5	24-hr; Annual	Volume	462,928.000	4,960,561.000	5.86E-01	7.38E-02	Nearby Source - Anchor Glass	EU003
AGCFS001_2	PM2.5	24-hr; Annual	Area Polygon	462,917.550	4,960,556.480	1.71E-07	1.26E-07	Nearby Source - Anchor Glass	FS001 FS002
AGCFUG13	PM2.5	24-hr; Annual	Area Polygon	463,010.000	4,960,535.140	8.00E-06	5.90E-06	Nearby Source - Anchor Glass	FUGI13

ID	Pollutant	Averaging time	Source Type	X1	Y1	Emission_Rate (lb/hr)	Emission_Rate (g/s)	Description	Permit ID
RAHSV003	PM2.5	24-hr; Annual	Point	457,513.660	4,960,520.100	5.07E-01	6.39E-02	Nearby Source - Rahr	EQUI30; EQUI31;
RAHSV011	PM2.5	24-hr; Annual	Point	457,455.290	4,960,474.720	1.82E+00	2.29E-01	Nearby Source - Rahr	EQUI063-64; EQUI092; EQUI266; EQUI067; EQUI212-227; EQUI239-241; EQUI236
RAHSV013	PM2.5	24-hr; Annual	Point	457,468.290	4,960,476.410	3.66E+00	4.61E-01	Nearby Source - Rahr	EQUI009-010; EQUI095-96; EQUI022; EQUI025; EQUI242; EQUI211; EQUI231; EQUI238; EQUI245-247; EQUI139-151; EQUI006
RAHSV012	PM2.5	24-hr; Annual	Point	457,426.480	4,960,469.950	2.61E+00	3.29E-01	Nearby Source - Rahr	EQUI088-91; EQUI134-135; EQUI210; EQUI228-230; EQUI243-244; EQUI266; EQUI012; EQUI016-18; EQUI232-237;
RAHSV028	PM2.5	24-hr; Annual	Point	457,317.630	4,960,480.480	2.10E+00	2.64E-01	Nearby Source - Rahr	EQUI007-008; EQUI098; EQUI105; EQUI110-EQUI113
RAHSV027	PM2.5	24-hr; Annual	Point	457,341.110	4,960,476.110	2.23E+00	2.81E-01	Nearby Source - Rahr	EQUI001-4; EQUI026-29; EQUI131
RAHSV026	PM2.5	24-hr; Annual	Point	457,340.110	4,960,480.720	3.48E+00	4.38E-01	Nearby Source - Rahr	EQUI130; EQUI154-162
RAHSV025	PM2.5	24-hr; Annual	Point	457,339.180	4,960,484.900	3.02E+00	3.81E-01	Nearby Source - Rahr	EQUI013; EQUI107-109; EQUI152-153
RAHSV017	PM2.5	24-hr; Annual	Point	457,509.510	4,960,430.660	1.35E+00	1.70E-01	Nearby Source - Rahr	EQUI011; EQUI014-015; EQUI116-117; EQUI196-197
RAHRSV8A	PM2.5	24-hr; Annual	Point	457,459.500	4,960,409.900	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8B	PM2.5	24-hr; Annual	Point	457,460.000	4,960,407.400	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8C	PM2.5	24-hr; Annual	Point	457,460.300	4,960,404.800	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8D	PM2.5	24-hr; Annual	Point	457,460.800	4,960,402.000	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8E	PM2.5	24-hr; Annual	Point	457,461.300	4,960,398.800	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8F	PM2.5	24-hr; Annual	Point	457,461.700	4,960,395.700	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8G	PM2.5	24-hr; Annual	Point	457,462.200	4,960,392.600	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8H	PM2.5	24-hr; Annual	Point	457,462.800	4,960,389.600	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8I	PM2.5	24-hr; Annual	Point	457,463.200	4,960,386.600	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8J	PM2.5	24-hr; Annual	Point	457,463.700	4,960,383.500	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8K	PM2.5	24-hr; Annual	Point	457,464.200	4,960,380.400	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8L	PM2.5	24-hr; Annual	Point	457,464.700	4,960,377.400	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8M	PM2.5	24-hr; Annual	Point	457,465.200	4,960,374.300	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8N	PM2.5	24-hr; Annual	Point	457,465.600	4,960,371.400	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV8O	PM2.5	24-hr; Annual	Point	457,466.000	4,960,368.300	6.99E-02	8.81E-03	Nearby Source - Rahr	EQUI284-289; EQUI36;
RAHRSV4A	PM2.5	24-hr; Annual	Point	457,497.600	4,960,527.500	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4B	PM2.5	24-hr; Annual	Point	457,497.900	4,960,525.900	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4C	PM2.5	24-hr; Annual	Point	457,498.200	4,960,524.400	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4D	PM2.5	24-hr; Annual	Point	457,498.400	4,960,523.100	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4E	PM2.5	24-hr; Annual	Point	457,498.600	4,960,521.700	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4F	PM2.5	24-hr; Annual	Point	457,498.900	4,960,520.200	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4G	PM2.5	24-hr; Annual	Point	457,499.200	4,960,518.500	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4H	PM2.5	24-hr; Annual	Point	457,499.400	4,960,516.700	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4I	PM2.5	24-hr; Annual	Point	457,499.800	4,960,514.900	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4J	PM2.5	24-hr; Annual	Point	457,500.100	4,960,512.900	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV4O	PM2.5	24-hr; Annual	Point	457,500.400	4,960,511.300	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5A	PM2.5	24-hr; Annual	Point	457,473.000	4,960,523.600	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5B	PM2.5	24-hr; Annual	Point	457,473.200	4,960,521.800	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5C	PM2.5	24-hr; Annual	Point	457,473.600	4,960,520.400	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5D	PM2.5	24-hr; Annual	Point	457,473.800	4,960,518.900	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5E	PM2.5	24-hr; Annual	Point	457,474.000	4,960,517.500	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5F	PM2.5	24-hr; Annual	Point	457,474.200	4,960,515.800	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5G	PM2.5	24-hr; Annual	Point	457,474.500	4,960,513.900	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5H	PM2.5	24-hr; Annual	Point	457,474.800	4,960,512.400	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5I	PM2.5	24-hr; Annual	Point	457,475.100	4,960,510.800	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5J	PM2.5	24-hr; Annual	Point	457,475.400	4,960,509.200	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV5O	PM2.5	24-hr; Annual	Point	457,475.700	4,960,507.500	2.40E-02	3.02E-03	Nearby Source - Rahr	EQUI32; EQUI33
RAHRSV6A	PM2.5	24-hr; Annual	Point	457,398.800	4,960,507.300	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6B	PM2.5	24-hr; Annual	Point	457,402.000	4,960,507.900	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6C	PM2.5	24-hr; Annual	Point	457,405.100	4,960,508.500	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6D	PM2.5	24-hr; Annual	Point	457,408.400	4,960,509.000	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6E	PM2.5	24-hr; Annual	Point	457,411.500	4,960,509.500	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6F	PM2.5	24-hr; Annual	Point	457,414.600	4,960,510.100	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6G	PM2.5	24-hr; Annual	Point	457,417.300	4,960,510.600	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6H	PM2.5	24-hr; Annual	Point	457,420.200	4,960,511.200	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6I	PM2.5	24-hr; Annual	Point	457,423.200	4,960,511.800	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV6J	PM2.5	24-hr; Annual	Point	457,426.300	4,960,512.300	9.37E-02	1.18E-02	Nearby Source - Rahr	EQUI248-253; EQUI34;
RAHRSV9A	PM2.5	24-hr; Annual	Point	457,572.800	4,960,440.700	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9B	PM2.5	24-hr; Annual	Point	457,576.400	4,960,441.300	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9C	PM2.5	24-hr; Annual	Point	457,579.800	4,960,441.800	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9D	PM2.5	24-hr; Annual	Point	457,583.300	4,960,442.300	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263

ID	Pollutant	Averaging time	Source Type	X1	Y1	Emission_Rate (lb/hr)	Emission_Rate (g/s)	Description	Permit ID
RAHRSV9E	PM2.5	24-hr; Annual	Point	457,586.700	4,960,442.900	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9F	PM2.5	24-hr; Annual	Point	457,589.800	4,960,443.200	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9G	PM2.5	24-hr; Annual	Point	457,593.100	4,960,443.800	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9H	PM2.5	24-hr; Annual	Point	457,596.800	4,960,444.400	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9I	PM2.5	24-hr; Annual	Point	457,600.600	4,960,444.800	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9J	PM2.5	24-hr; Annual	Point	457,604.200	4,960,445.300	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9K	PM2.5	24-hr; Annual	Point	457,607.700	4,960,445.900	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9L	PM2.5	24-hr; Annual	Point	457,611.200	4,960,446.600	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9M	PM2.5	24-hr; Annual	Point	457,614.500	4,960,447.100	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9N	PM2.5	24-hr; Annual	Point	457,618.000	4,960,447.500	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9O	PM2.5	24-hr; Annual	Point	457,621.700	4,960,448.000	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRSV9P	PM2.5	24-hr; Annual	Point	457,625.500	4,960,448.500	1.01E-01	1.27E-02	Nearby Source - Rahr	EQUI254-263
RAHRS10A	PM2.5	24-hr; Annual	Point	457,275.100	4,960,484.600	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRS10B	PM2.5	24-hr; Annual	Point	457,275.600	4,960,481.100	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRS10C	PM2.5	24-hr; Annual	Point	457,276.100	4,960,478.100	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRS10D	PM2.5	24-hr; Annual	Point	457,276.700	4,960,475.000	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRS10E	PM2.5	24-hr; Annual	Point	457,277.100	4,960,471.800	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRS10F	PM2.5	24-hr; Annual	Point	457,277.600	4,960,468.600	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRS10G	PM2.5	24-hr; Annual	Point	457,278.100	4,960,465.400	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRS10J	PM2.5	24-hr; Annual	Point	457,279.000	4,960,461.500	1.48E-01	1.87E-02	Nearby Source - Rahr	EQUI264-265
RAHRSV7A	PM2.5	24-hr; Annual	Point	457,454.400	4,960,518.100	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7B	PM2.5	24-hr; Annual	Point	457,454.700	4,960,516.100	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7C	PM2.5	24-hr; Annual	Point	457,455.100	4,960,514.300	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7D	PM2.5	24-hr; Annual	Point	457,455.500	4,960,512.400	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7E	PM2.5	24-hr; Annual	Point	457,455.800	4,960,510.400	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7F	PM2.5	24-hr; Annual	Point	457,456.000	4,960,508.500	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7G	PM2.5	24-hr; Annual	Point	457,456.100	4,960,506.600	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7H	PM2.5	24-hr; Annual	Point	457,456.600	4,960,504.600	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7I	PM2.5	24-hr; Annual	Point	457,456.700	4,960,502.900	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7J	PM2.5	24-hr; Annual	Point	457,456.900	4,960,501.000	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7K	PM2.5	24-hr; Annual	Point	457,457.200	4,960,499.300	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7L	PM2.5	24-hr; Annual	Point	457,457.300	4,960,497.200	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7M	PM2.5	24-hr; Annual	Point	457,457.600	4,960,495.200	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7N	PM2.5	24-hr; Annual	Point	457,457.800	4,960,493.600	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7O	PM2.5	24-hr; Annual	Point	457,458.200	4,960,491.500	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7P	PM2.5	24-hr; Annual	Point	457,458.400	4,960,489.800	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7Q	PM2.5	24-hr; Annual	Point	457,458.900	4,960,488.000	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7R	PM2.5	24-hr; Annual	Point	457,459.400	4,960,485.700	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7S	PM2.5	24-hr; Annual	Point	457,459.900	4,960,483.900	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHRSV7T	PM2.5	24-hr; Annual	Point	457,460.100	4,960,481.900	2.21E-02	2.79E-03	Nearby Source - Rahr	EQUI035
RAHSV075	PM2.5	24-hr; Annual	Point	457,455.110	4,960,391.770	4.66E-01	5.87E-02	Nearby Source - Rahr	EQUI193
RAHSV078	PM2.5	24-hr; Annual	Point	457,456.290	4,960,382.250	4.66E-01	5.87E-02	Nearby Source - Rahr	EQUI202
RAHSV079	PM2.5	24-hr; Annual	Point	457,686.000	4,960,671.000	1.06E+00	1.33E-01	Nearby Source - Rahr	EQUI198-201; EQUI207-208
RAHSV080	PM2.5	24-hr; Annual	Point	457,742.000	4,960,654.000	8.49E-01	1.07E-01	Nearby Source - Rahr	EQUI269-283
RAHSV76A	PM2.5	24-hr; Annual	Point	457,497.300	4,960,352.600	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76B	PM2.5	24-hr; Annual	Point	457,500.970	4,960,353.210	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76C	PM2.5	24-hr; Annual	Point	457,504.630	4,960,353.820	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76D	PM2.5	24-hr; Annual	Point	457,508.300	4,960,354.430	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76E	PM2.5	24-hr; Annual	Point	457,511.970	4,960,355.040	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76F	PM2.5	24-hr; Annual	Point	457,515.630	4,960,355.660	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76G	PM2.5	24-hr; Annual	Point	457,519.300	4,960,356.270	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76H	PM2.5	24-hr; Annual	Point	457,522.970	4,960,356.880	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76I	PM2.5	24-hr; Annual	Point	457,526.630	4,960,357.490	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV76J	PM2.5	24-hr; Annual	Point	457,530.300	4,960,358.100	7.83E-02	9.87E-03	Nearby Source - Rahr	EQUI203
RAHSV077	PM2.5	24-hr; Annual	Point	457,481.700	4,960,381.250	8.25E-02	1.04E-02	Nearby Source - Rahr	EQUI194-195; EQUI205-206
RAHSV081	PM2.5	24-hr; Annual	Point	457,541.100	4,960,376.600	6.43E-02	8.10E-03	Nearby Source - Rahr	NOT IN CURRENT PERMIT
RAHE268A	PM2.5	24-hr; Annual	Volume	457,682.100	4,960,675.800	7.73E-02	9.74E-03	Nearby Source - Rahr	EQUI268
RAHE268B	PM2.5	24-hr; Annual	Volume	457,716.110	4,960,682.530	7.73E-02	9.74E-03	Nearby Source - Rahr	EQUI268

MINNESOTA POLLUTION CONTROL AGENCY
520 Lafayette Road North
St. Paul, MN 55155-4194

AQDM-02

Air Quality Dispersion Modeling (AQDM) protocol spreadsheet

(Previously AQDMPS-01)

Doc Type: Air Dispersion Modeling

Note: Permit applicants may create their own spreadsheet tabs.

AQ Facility ID number:	13900010
Facility name:	Xcel Energy - Blue Lake
Facility address:	1200 70th Street S Shakopee, MN 55379-2100
Facility contact:	Michael Aasen

							Easting	Northing									
Permit	AERMOD	Pollutant	Averaging Time	Operating scenario	Scalar/Variable emissions_type	Release_Type	X1	Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	Exit_Temp	Exit_Vel	Diam	Flow rate	Description	SO EMISFACT Description
ID	ID			#			[m]	[m]	[m]	[lb/hr]	[g/sec]	[m]	[K]	[m/s]	[m]	[ACFM]		
EU001	AGCSV001	NOX	1-hour	NAAQS		Vertical	462929.93	4,960,616.300	224.600	8.07E+01	10.16613899	38.1	560.928	18.37944	1.423	61935.31	Nearby Source - Anchor Glass	
EU002	AGCSV003	NOX	1-hour	NAAQS		Vertical	462918.81	4,960,581.540	224.960	8.16E+01	10.27701713	38.1	560.928	16.55064	1.423	55772.59	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV701	NOX	1-hour	NAAQS		Horizontal	462979.12	4,960,617.580	224.810	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV702	NOX	1-hour	NAAQS		Horizontal	462977.62	4,960,612.320	224.840	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV703	NOX	1-hour	NAAQS		Horizontal	462976.01	4,960,606.740	224.860	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV704	NOX	1-hour	NAAQS		Horizontal	462974.29	4,960,601.050	224.870	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV705	NOX	1-hour	NAAQS		Horizontal	462972.68	4,960,595.370	224.870	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV706	NOX	1-hour	NAAQS		Horizontal	462970.96	4,960,589.140	224.870	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV707	NOX	1-hour	NAAQS		Horizontal	462969.14	4,960,583.020	224.860	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV708	NOX	1-hour	NAAQS		Horizontal	462967.53	4,960,577.550	224.870	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV709	NOX	1-hour	NAAQS		Horizontal	462965.81	4,960,571.330	224.920	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV710	NOX	1-hour	NAAQS		Horizontal	462964.1	4,960,565.640	224.950	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV711	NOX	1-hour	NAAQS		Horizontal	462962.92	4,960,560.910	224.970	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU016-EU021	AGCSV712	NOX	1-hour	NAAQS		Horizontal	462961.31	4,960,555.760	224.980	1.96E-01	0.024695585	21.336	294.261	2.40792	4.459	79673.38	Nearby Source - Anchor Glass	
EU001-EU021	BLW001	NOX	1-hour	NAAQS		Vertical	465705.2585	4,960,489.718	224.600	5.08E+00	6.396E-01	51.816	1116.483333	1.40	1.8288	7800.00	Nearby Source - Met Council Blue Lake WWTP	Actual RTO TPY converted to lb/hr using actual hours of operation plus the total lb/hr PTE from Attachment 3 (EU001-EU021)
EQUI73	KESST010	NOX	1-hour	(Screened Out)		Vertical	457447.17	4,960,367.140	230.540	7.71E+01	9.708138	67.056	454.261	20.70483	1.981	135218.73	Nearby Source - Koda Energy	
EU012; EU043	CTCSV004	PM2.5	24-hr; Annual	NAAQS		Vertical	462072.8	4,960,751.600	225.640	7.86E+00	0.99	19.81	449.82	30.55	1.07	58206.97	Nearby Source - CertainTeed	
EU008	CTCSV005	PM2.5	24-hr; Annual	NAAQS		Vertical	462059	4,960,715.500	225.650	4.60E-02	5.80E-03	25.3	755.37	10.16	0.31	1624.85	Nearby Source - CertainTeed	
EU009	CTCSV006	PM2.5	24-hr; Annual	NAAQS		Vertical	462059.1	4,960,721.500	225.650	7.39E-02	9.31E-03	25.3	755.37	10.16	0.7	8284.88	Nearby Source - CertainTeed	
EU010	CTCSV007	PM2.5	24-hr; Annual	NAAQS		Vertical	462059.1	4,960,727.600	225.650	7.39E-02	9.31E-03	25.3	755.37	10.16	0.7	8284.88	Nearby Source - CertainTeed	
EU013	CTCSV008	PM2.5	24-hr; Annual	NAAQS		Vertical	462080.3	4,960,710.900	225.650	1.02E-01	1.28E-02	15.24	755.37	5.74	0.61	3554.41	Nearby Source - CertainTeed	
EU021	CTCSV011	PM2.5	24-hr; Annual	NAAQS		Vertical	462027.55	4,960,686.020	225.530	1.00E-01	0.012599788	16.764	298.15	1.95072	0.61	1207.96	Nearby Source - CertainTeed	
EU011; EU023	CTCSV013	PM2.5	24-hr; Annual	NAAQS		Vertical	462031.1	4,960,683.200	225.650	2.48E-01	3.12E-02	21.34	298.15	14.82	0.94	21792.15	Nearby Source - CertainTeed	
EU015	CTCSV014	PM2.5	24-hr; Annual	NAAQS		Vertical	462034.3	4,960,668.900	225.650	7.06E-02	8.90E-03	12.5	560.93	8.89	0.41	2486.94	Nearby Source - CertainTeed	
EU020	CTCSV017	PM2.5	24-hr; Annual	NAAQS		Horizontal	462044	4,960,729.800	225.650	2.06E-01	2.59E-02	22.25	298.15	46.15	0.18	2488.36	Nearby Source - CertainTeed	
EU020	CTCSV018	PM2.5	24-hr; Annual	NAAQS		Horizontal	462038.24	4,960,685.270	225.490	4.00E-02	0.005039915	22.25	298.15	12.954	0.152	498.07	Nearby Source - CertainTeed	
EU012; EU025	CTCSV019	PM2.5	24-hr; Annual	NAAQS		Vertical	462041.4	4,960,696.500	225.650	2.48E-01	3.12E-02	21.34	298.15	12.3	0.69	9745.40	Nearby Source - CertainTeed	
EU026	CTCSV020	PM2.5	24-hr; Annual	NAAQS		Vertical	462039.6	4,960,694.700	225.650	3.86E-02	4.86E-03	16.76	298.15	0.73	0.61	452.04	Nearby Source - CertainTeed	
EU028	CTCSV022	PM2.5	24-hr; Annual	NAAQS		Vertical	462048	4,960,697.900	225.650	1.54E-01	1.94E-02	16.76	394.26	11.64	0.3	1743.38	Nearby Source - CertainTeed	
EU047	CTCSV040	PM2.5	24-hr; Annual	NAAQS		Vertical	462033.5	4,960,634.100	225.650	3.25E-01	4.10E-02	23.47	298.15	5.79	0.63	3824.33	Nearby Source - CertainTeed	
EU048	CTCSV041	PM2.5	24-hr; Annual	NAAQS		Vertical	462033.6	4,960,640.900	225.650	3.25E-01	4.10E-02	23.47	298.15	5.79	0.63	3824.33	Nearby Source - CertainTeed	
EU049	CTCSV042	PM2.5	24-hr; Annual	NAAQS		Horizontal	462045.8	4,960,672.500	225.650	2.32E-01	2.92E-02	44.5	424.82	17.46	0.3	2615.07	Nearby Source - CertainTeed	
EU051	CTCSV043	PM2.5	24-hr; Annual	NAAQS		Horizontal	462039.1	4,960,663.500	225.650	3.00E-02	3.78E-03	24.38	298.15	9.06	0.15	339.24	Nearby Source - CertainTeed	
EU050; EU052; EU074; EU081-86	CTCSV044	PM2.5	24-hr; Annual	NAAQS		Vertical	462048.9	4,960,658.600	225.650	2.54E+00	0.32	44.5	298.15	31.05	0.76	29845.92	Nearby Source - CertainTeed	
EU053	CTCSV045	PM2.5	24-hr; Annual	NAAQS		Horizontal	462047.6	4,960,665.900	225.650	5.91E-01	7.45E-02	44.5	488.71	19.84	0.46	6986.40	Nearby Source - CertainTeed	
EU024	CTCSV046	PM2.5	24-hr; Annual	NAAQS		Horizontal	462048.7	4,960,689.400	225.650	2.32E-01	2.92E-02	21.95	298.15	8.19	0.45	2759.98	Nearby Source - CertainTeed	
EU070; EU075	CTCSV047	PM2.5	24-hr; Annual	NAAQS		Horizontal	462038	4,960,682.600	225.650	2.46E+00	0.31	17.07	298.15	22.15	0.76	21291.05	Nearby Source - CertainTeed	
EU070; EU076; EU088	CTCSV048	PM2.5	24-hr; Annual	NAAQS		Horizontal	462019.4	4,960,697.400	225.650	1.98E+00	0.25	8.53	298.15	22.15	0.76	21291.05	Nearby Source - CertainTeed	
EU070; EU077; EU088	CTCSV049	PM2.5	24-hr; Annual	NAAQS		Horizontal	462037.9	4,960,697.500	225.650	1.59E+00	0.2	8.53	298.15	12.42	0.76	11938.37	Nearby Source - CertainTeed	
EU070; EU078; EU088	CTCSV050	PM2.5	24-hr; Annual	NAAQS		Horizontal	462035	4,960,697.400	225.650	1.27E+00	0.16	8.53	298.15	12.42	0.76	11938.37	Nearby Source - CertainTeed	
EU070; EU079; EU088	CTCSV051	PM2.5	24-hr; Annual	NAAQS		Vertical	462034.5	4,960,661.500	225.650	2.78E+00	0.35	9.75	298.15	19.54	1.07	37229.60	Nearby Source - CertainTeed	
EU070; EU080; EU088	CTCSV052	PM2.5	24-hr; Annual	NAAQS		Vertical	462032	4,960,661.500	225.650	2.22E+00	0.28	10.67	298.15	26.4	1.07	50299.97	Nearby Source - CertainTeed	
EU013; EU014	CTCSV053	PM2.5	24-hr; Annual	NAAQS		Vertical	462048.9	4,960,644.700	225.650	2.10E-01	2.64E-02	13.11	755.37	3.32	0.64	2263.05	Nearby Source - CertainTeed	
EU087	CTCSV056	PM2.5	24-hr; Annual	NAAQS		Vertical	462059	4,960,733.000	225.650	7.39E-02	9.31E-03	17.83	553.15	2.88	0.61	1783.40	Nearby Source - CertainTeed	
EU090	CTCSV057	PM2.5	24-hr; Annual	NAAQS		Vertical	462124.8	4,960,712.900	225.550	1.27E+00	0.16	3.81	294.26	11.84	2.29	103328.21	Nearby Source - CertainTeed	
EU091-093	CTCSV058	PM2.5	24-hr; Annual	NAAQS		Vertical	462074.2	4,960,817.100	225.270	9.52E-01	0.12	16.46	699.82	18.69	1.37	58377.66	Nearby Source - CertainTeed	
EU070; EU094	CTCSV060	PM2.5	24-hr; Annual	NAAQS		Vertical	462030.7	4,960,697.500	225.650	6.60E-01	8.32E-02	8.53	298.15	12.42	0.76	11938.37	Nearby Source - CertainTeed	
EU070; EU095	CTCSV061	PM2.5	24-hr; Annual	NAAQS		Vertical	462034.6	4,960,697.500	225.650	9.52E-01	0.12	8.53	298.15	12.42	0.76	11938.37	Nearby Source - CertainTeed	
EU070; EU096	CTCSV062	PM2.5	24-hr; Annual	NAAQS		Vertical	462021.2	4,960,661.500	225.650	1.11E+00	0.14	9.75	298.15	26.4	1.07	50299.97	Nearby Source - CertainTeed	
EU070; EU097	CTCSV063	PM2.5	24-hr; Annual	NAAQS		Vertical	462024.8	4,960,661.500	225.650	1.67E+00	0.21	9.75	298.15	26.4	1.07	50299.97	Nearby Source - CertainTeed	
EU070; EU098	CTCSV064	PM2.5	24-hr; Annual	NAAQS		Vertical	462028.4	4,960,661.500	225.650	8.73E-01	0.11	9.75	298.15	26.39	1.07	50280.92	Nearby Source - CertainTeed	
EU099; EU100	CTCSV065	PM2.5	24-hr; Annual	NAAQS		Vertical	462096.2	4,960,722.600	225.650	6.71E-01	8.45E-02	10.67	483.15	10.77	0.61	6669.17	Nearby Source - CertainTeed	
NOT IN CURRENT PERMIT	CTCSV066	PM2.5	24-hr; Annual	NAAQS		Vertical	462092.2	4,960,762.400	225.540	2.44E-01	3.07E-02	10.67	622.04	10.16	0.64	6925.48	Nearby Source - CertainTeed	
NOT IN CURRENT PERMIT	CTCSV069	PM2.5	24-hr; Annual	NAAQS		Vertical	462120.4	4,960,826.900	225.020	6.11E-02	7.70E-03	13.72	380.37	7.28	0.41	2036.55	Nearby Source - CertainTeed	
EU001	AGCSV001	PM2.5	24-hr; Annual	NAAQS		Vertical	462,929.930	4,960,616.300	224.6	1.33E+01	1.68	38.1	560.928	18.37944	1.423	61935.31	Nearby Source - Anchor Glass	
EU002	AGCSV003	PM2.5	24-hr; Annual	NAAQS		Vertical	462,918.810	4,960,581.540	224.96	1.35E+01	1.7	38.1	560.928	16.55064	1.423	55772.59	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV701	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,979.120	4,960,617.580	224.81	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV702	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,977.620	4,960,612.320	224.84	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV703	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,976.010	4,960,606.740	224.86	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV704	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,974.290	4,960,601.050	224.87	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV705	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,972.680	4,960,595.370	224.87	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV706	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,970.960	4,960,589.140	224.87	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV707	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,969.140	4,960,583.020	224.86	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV708	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,967.530	4,960,577.550	224.87	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV709	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,965.810	4,960,571.330	224.92	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV710	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,964.100	4,960,565.640	224.95	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV711	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,962.920	4,960,560.910	224.97	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU009-12; EU014-EU015; EU016-EU021	AGCSV712	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,961.310	4,960,555.760	224.98	5.51E-01	0.069424832	21.336	294.261	2.40792	4.45	79352.08	Nearby Source - Anchor Glass	
EU003, EU005	AGCSV005	PM2.5	24-hr; Annual	NAAQS		Vertical	462,926.280	4,960,559.650	224.74	3.83E-01	0.048257188	35.662	294.261	43.61688	0.24	4180.93	Nearby Source - Anchor Glass	
EU006	AGCSV006	PM2.5	24-hr; Annual	NAAQS		Vertical	462,932.980	4,960,613.490	224.58	4.80E-01	0.060478983	4.724	294.261	19.5072	0.41	5457.06	Nearby Source - Anchor Glass	
EU024	AGCSV008	PM2.5	24-hr; Annual	NAAQS		Horizontal	462,992.630	4,960,534.550	225.09	6.86E-01	0.086434546	4.938	294.261	48.37176	0.31	7735.91	Nearby Source - Anchor Glass	
EU004	AGCSV009	PM2.5	24-hr; Annual	NAAQS		Vertical	462,916.060	4,960,565.500	224.96	3.83E-01	0.048257188	25.908	294.261	43.61688	0.24	4180.93	Nearby Source - Anchor Glass	
IA	AGCCT1	PM2.5	24-hr; Annual	NAAQS		Vertical	462,883.890	4,960,628.500	224.74	1.70E-02	0.002141964	3.962	294.261	9.144	1.829	50904.93	Nearby Source - Anchor Glass	
IA	AGCCT2	PM2.5	24-hr; Annual	NAAQS		Vertical	462,887.590	4,960,627.280	224.76	1.70E-02	0.002141964	3.962	294.261	9.144	1.829	50904.93	Nearby Source - Anchor Glass	

							Easting	Northing										
Permit	AERMOD	Pollutant	Averaging Time	Operating scenario	Scalar/Variable emissions_type	Release_Type	X1	Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	Exit_Temp	Exit_Vel	Diam	Flow rate	Description	SO EMISFACT Description
EQUI30; EQUI31;	RAHSV003	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,513.660	4,960,520.100	228.9	5.07E-01	0.06388094	23.47	322.039	19.26433	4.31	595531.44	Nearby Source - Rahr	
EQUI063-64; EQUI092; EQUI266; EQUI067; EQUI212-227; EQUI239-241; EQUI236	RAHSV011	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,455.290	4,960,474.720	229.32	1.82E+00	0.229	19.2	294	0.001	1.219	2.47	Nearby Source - Rahr	
EQUI009-010; EQUI095-96; EQUI022; EQUI025; EQUI242; EQUI211; EQUI231; EQUI238; EQUI245-247; EQUI139-151; EQUI006	RAHSV013	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,468.290	4,960,476.410	229.46	3.66E+00	0.461	17.7	294	0.001	1.219	2.47	Nearby Source - Rahr	
EQUI088-91; EQUI134-135; EQUI210; EQUI228-230; EQUI243-244; EQUI266; EQUI012; EQUI016-18; EQUI232-237;	RAHSV012	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,426.480	4,960,469.950	229.01	2.61E+00	0.329	24.1	294	0.001	1.036	1.79	Nearby Source - Rahr	
EQUI007-008; EQUI098; EQUI105; EQUI110-EQUI113	RAHSV028	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,317.630	4,960,480.480	228.31	2.10E+00	0.264	3.66	294	13.763	1.036	24582.66	Nearby Source - Rahr	
EQUI001-4; EQUI026-29; EQUI131	RAHSV027	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,341.110	4,960,476.110	228.6	2.23E+00	0.281	10	294	0.001	1.036	1.79	Nearby Source - Rahr	
EQUI130; EQUI154-162	RAHSV026	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,340.110	4,960,480.720	228.55	3.48E+00	0.438	10	294	0.001	1.036	1.79	Nearby Source - Rahr	
EQUI013; EQUI107-109; EQUI152-153	RAHSV025	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,339.180	4,960,484.900	228.51	3.02E+00	0.381	10	294	0.001	1.036	1.79	Nearby Source - Rahr	
EQUI011; EQUI014-015; EQUI116-117; EQUI196-197	RAHSV017	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,509.510	4,960,430.660	230.6	1.35E+00	0.17	12	294	0.001	0.715	0.85	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,459.500	4,960,409.900	230.13	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,460.000	4,960,407.400	230.18	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,460.300	4,960,404.800	230.24	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,460.800	4,960,402.000	230.3	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,461.300	4,960,398.800	230.37	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,461.700	4,960,395.700	230.44	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,462.200	4,960,392.600	230.46	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8H	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,462.800	4,960,389.600	230.49	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8I	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,463.200	4,960,386.600	230.51	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,463.700	4,960,383.500	230.52	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8K	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,464.200	4,960,380.400	230.54	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8L	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,464.700	4,960,377.400	230.55	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8M	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,465.200	4,960,374.300	230.57	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8N	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,465.600	4,960,371.400	230.58	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI284-289; EQUI36;	RAHRSV8O	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,466.000	4,960,368.300	230.58	6.99E-02	0.00881	22.86	341.483	5.45577	1.714	26673.13	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,497.600	4,960,527.500	228.42	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,497.900	4,960,525.900	228.39	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,498.200	4,960,524.400	228.37	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,498.400	4,960,523.100	228.36	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,498.600	4,960,521.700	228.35	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,498.900	4,960,520.200	228.34	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,499.200	4,960,518.500	228.34	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4H	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,499.400	4,960,516.700	228.4	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4I	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,499.800	4,960,514.900	228.46	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,500.100	4,960,512.900	228.52	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV4O	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,500.400	4,960,511.300	228.57	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,473.000	4,960,523.600	228.43	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,473.200	4,960,521.800	228.46	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,473.600	4,960,520.400	228.49	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,473.800	4,960,518.900	228.52	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,474.000	4,960,517.500	228.56	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,474.200	4,960,515.800	228.61	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,474.500	4,960,513.900	228.67	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5H	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,474.800	4,960,512.400	228.71	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5I	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,475.100	4,960,510.800	228.76	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,475.400	4,960,509.200	228.81	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI32; EQUI33	RAHRSV5O	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,475.700	4,960,507.500	228.87	2.40E-02	0.00302	23.165	310.928	0.001	1.301	2.82	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,398.800	4,960,507.300	228.41	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,402.000	4,960,507.900	228.42	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,405.100	4,960,508.500	228.44	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,408.400	4,960,509.000	228.45	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,411.500	4,960,509.500	228.46	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,414.600	4,960,510.100	228.47	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,417.300	4,960,510.600	228.47	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	

							Easting	Northing										
Permit	AERMOD	Pollutant	Averaging Time	Operating scenario	Scalar/Variable emissions_type	Release_Type	X1	Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	Exit_Temp	Exit_Vel	Diam	Flow rate	Description	SO EMISFACT Description
EQUI248-253; EQUI34;	RAHRSV6H	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,420.200	4,960,511.200	228.47	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6I	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,423.200	4,960,511.800	228.47	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI248-253; EQUI34;	RAHRSV6J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,426.300	4,960,512.300	228.48	9.37E-02	0.0118	38.405	341.483	5.09971	1.942	32006.65	Nearby Source - Rahr	
EQUI254-263	RAHRSV9A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,572.800	4,960,440.700	230.85	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,576.400	4,960,441.300	230.9	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,579.800	4,960,441.800	230.94	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,583.300	4,960,442.300	230.98	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,586.700	4,960,442.900	231.02	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,589.800	4,960,443.200	231.06	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,593.100	4,960,443.800	231.1	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9H	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,596.800	4,960,444.400	231.15	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9I	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,600.600	4,960,444.800	231.2	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,604.200	4,960,445.300	231.25	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9K	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,607.700	4,960,445.900	231.3	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9L	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,611.200	4,960,446.600	231.31	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9M	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,614.500	4,960,447.100	231.31	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9N	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,618.000	4,960,447.500	231.32	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9O	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,621.700	4,960,448.000	231.33	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI254-263	RAHRSV9P	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,625.500	4,960,448.500	231.34	1.01E-01	0.0127	30.48	341.483	5.36102	1.905	32376.78	Nearby Source - Rahr	
EQUI264-265	RAHRS10A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,275.100	4,960,484.600	227.88	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI264-265	RAHRS10B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,275.600	4,960,481.100	227.89	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI264-265	RAHRS10C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,276.100	4,960,478.100	227.9	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI264-265	RAHRS10D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,276.700	4,960,475.000	227.91	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI264-265	RAHRS10E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,277.100	4,960,471.800	227.92	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI264-265	RAHRS10F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,277.600	4,960,468.600	227.93	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI264-265	RAHRS10G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,278.100	4,960,465.400	227.94	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI264-265	RAHRS10J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,279.000	4,960,461.500	227.97	1.48E-01	0.0187	37.49	341.483	8.00537	2.794	103999.31	Nearby Source - Rahr	
EQUI035	RAHRSV7A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,454.400	4,960,518.100	228.85	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,454.700	4,960,516.100	228.87	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,455.100	4,960,514.300	228.88	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,455.500	4,960,512.400	228.9	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,455.800	4,960,510.400	228.92	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,456.000	4,960,508.500	228.94	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,456.100	4,960,506.600	228.96	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7H	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,456.600	4,960,504.600	228.99	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7I	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,456.700	4,960,502.900	229.01	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,456.900	4,960,501.000	229.04	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7K	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,457.200	4,960,499.300	229.06	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7L	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,457.300	4,960,497.200	229.09	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7M	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,457.600	4,960,495.200	229.12	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7N	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,457.800	4,960,493.600	229.14	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7O	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,458.200	4,960,491.500	229.18	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7P	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,458.400	4,960,489.800	229.21	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7Q	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,458.900	4,960,488.000	229.24	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7R	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,459.400	4,960,485.700	229.27	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7S	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,459.900	4,960,483.900	229.29	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI035	RAHRSV7T	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,460.100	4,960,481.900	229.31	2.21E-02	0.00279	24.994	341.483	4.09956	1.579	17009.74	Nearby Source - Rahr	
EQUI193	RAHSV075	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,455.110	4,960,391.770	230.33	4.66E-01	0.0587	24.38	465.93	21.65	1.22	53625.80	Nearby Source - Rahr	
EQUI202	RAHSV078	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,456.290	4,960,382.250	230.43	4.66E-01	0.0587	24.38	465.93	21.65	1.22	53625.80	Nearby Source - Rahr	
EQUI198-201; EQUI207-208	RAHSV079	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,686.000	4,960,671.000	225.07	1.06E+00	0.133	4.57	294.26	17.15	0.51	7423.36	Nearby Source - Rahr	
EQUI269-283	RAHSV080	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,742.000	4,960,654.000	226.13	8.49E-01	0.107	9.14	294.26	23.19	0.62	14834.75	Nearby Source - Rahr	
EQUI203	RAHSV76A	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,497.300	4,960,352.600	230.74	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76B	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,500.970	4,960,353.210	230.79	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76C	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,504.630	4,960,353.820	230.83	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76D	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,508.300	4,960,354.430	230.87	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76E	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,511.970	4,960,355.040	230.91	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	

Permit	AERMOD	Pollutant	Averaging Time	Operating scenario	Scalar/Variable emissions_type	Release_Type	Easting X1	Northing Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	Exit_Temp	Exit_Vel	Diam	Flow rate	Description	SO EMISFACT Description
EQUI203	RAHSV76F	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,515.630	4,960,355.660	230.95	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76G	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,519.300	4,960,356.270	230.99	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76H	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,522.970	4,960,356.880	231.04	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76I	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,526.630	4,960,357.490	231.09	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI203	RAHSV76J	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,530.300	4,960,358.100	231.14	7.83E-02	0.00987	19.81	305.37	5.49	2.48	56191.67	Nearby Source - Rahr	
EQUI194-195; EQUI205-206	RAHSV077	PM2.5	24-hr; Annual	(Screened Out with Background)		Vertical	457,481.700	4,960,381.250	230.75	8.25E-02	0.0104	13.72	294.26	14.37	0.46	5060.21	Nearby Source - Rahr	

MINNESOTA POLLUTION CONTROL AGENCY
520 Lafayette Road North
St. Paul, MN 55155-4194

AQDM-02

Air Quality Dispersion Modeling (AQDM) protocol spreadsheet

(Previously AQDMPS-01)

Doc Type: Air Dispersion Modeling

Note: Permit applicants may create their own spreadsheet tabs.

AQ Facility ID number:	13900010
Facility name:	Xcel Energy - Blue Lake
Facility address:	1200 70th Street S Shakopee, MN 55379-2100
Facility contact:	Michael Aasen

						Easting	Northing					Lateral dimension	Vertical dimension		
Permit	AERMOD	Pollutant	Averaging time	Operating scenario	Scalar/Variable emissions_type	X1	Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	SigmaY	SigmaZ	Length_X	
ID	ID					[m]	[m]	[m]	(lb/hr)	(g/sec)	[m]	[m]	[m]	[m]	Description
EQUI30	AGCEQUI30	NOX	1-hour	NAAQS		463,218.000	4,960,435.000	225.31	3.43E-01	4.32E-02	3.96	1.07	3.69		Nearby Source - Anchor Glass (No EQUI30 or EQUI31 listed in current air permit. Assume this is space heating emissions?)
EQUI31	AGCEQUI31	NOX	1-hour	NAAQS		463,040.000	4,960,462.000	225	5.34E-01	6.73E-02	3.96	1.07	3.69		Nearby Source - Anchor Glass (No EQUI30 or EQUI31 listed in current air permit. Assume this is space heating emissions?)
No EQUI in Permit	KESVL001	NOX	1-hour	(Screened Out)		457,406.200	4,960,362.500	230.58	1.10E-01	1.39E-02	9.84	4.19	19.66		Nearby Source - Koda Energy (BoilerHouse Heater Emissions per input file)
No EQUI in Permit	KESVL002	NOX	1-hour	(Screened Out)		457,414.500	4,960,348.000	230.43	9.00E-02	1.13E-02	2.82	1.60	5.64		Nearby Source - Koda Energy (Ash Building Heater Emissions per input file)
EQUI30	AGCEQUI30	PM2.5	24-hour; Annual	NAAQS		463,218.000	4,960,435.000	225.310	2.60E-02	3.28E-03	3.96	1.07	3.69		Nearby Source - Anchor Glass (No EQUI30 or EQUI31 listed in current air permit. Assume this is space heating emissions?)
EQUI31	AGCEQUI31	PM2.5	24-hour; Annual	NAAQS		463,040.000	4,960,462.000	225.000	4.10E-02	5.17E-03	3.96	1.07	3.69		Nearby Source - Anchor Glass (No EQUI30 or EQUI31 listed in current air permit. Assume this is space heating emissions?)
EU013	AGCEU013	PM2.5	24-hour; Annual	NAAQS		462,962.000	4,960,543.000	225.040	4.35E-02	5.48E-03	3.96	2.84	3.69		Nearby Source - Anchor Glass No EU13 listed in current air permit. Assume this is a raw material handling source)
EU003	AGCEU003	PM2.5	24-hour; Annual	NAAQS		462,928.000	4,960,561.000	224.740	5.86E-01	7.38E-02	17.07	2.47	15.88		Nearby Source - Anchor Glass (Raw materials unloading; fugitive component not captured by baghouse)

MINNESOTA POLLUTION CONTROL AGENCY
520 Lafayette Road North
St. Paul, MN 55155-4194

AQDM-02

Air Quality Dispersion Modeling (AQDM) protocol spreadsheet

(Previously AQDMPS-01)

Doc Type: Air Dispersion Modeling

Note: Permit applicants may create their own spreadsheet tabs.

AQ Facility ID number:	
Facility name:	
Facility address:	
Facility contact:	

Model Input Key

Parameters	Units	Description
Permit ID		ID given in Permit or contact MPCA permit engineer
AERMOD ID		3-character facility ID plus AREA source ID used in Modeling (up to 8 characters), e.g. FACFS001
Pollutant		Criteria pollutant modeled, PM2.5, PM10, SO2, NO2, CO, Pb, O3
Averaging time		Modeling Period for pollutant, 1-HR, 24-HR, Annual, etc.
Operating scenario	[#]	A number indicating the operating condition, described in the Emission Calculations tab, for which the emission rate will be modeled.
Scalar/Variable emissions_type		By Season (SEASON); By Month (MONTH); By Hour-of-Day (HROFDY); By Wind Speed (WSPEED); By Season/Hour (SEASHR); By Season/Hour/Day (SHRDOW); By Season/Hour/Seven Days (SHRDOW7); By Month/Hour/Day (MHRDOW); By Month/Hour/Seven Days (MHRDOW7); By Hour/Seven Days (HRDOW7); By Hour/Day (HRDOW)
X1 =	[m]	X coordinate of source location [m] Enter here the X coordinate for the vertex of the area source that occurs in the southwest quadrant of the source.
Y1 =	[m]	Y coordinate of source location [m] Enter here the Y coordinate for the vertex of the area source that occurs in the southwest quadrant of the source.
Base_Elev =	[m]	Source base elevation above mean sea level
Emission_Rate =	[g/s/m2]	Emission rate (g/s for POINT, POINTCAP, POINTHOR, and VOLUME; g/s/m^2 for AREA, AREAPOLY, AREACIRC, and OPENPIT)
Height =	[m]	Release height above ground
Length_X =	[m]	X side length of the AREA
Length_Y =	[m]	Y side length of the AREA
Rotation angle	[deg]	
SigmaZ =	[m]	Initial sigma Z (optional for all AREA)
Num_Coords =		Number of coordinate pairs (POINT = 1, VOLUME = 1, OPENPIT = 1, AREA = 1, AREA_CIRC = 1, AREA_POLY >= 3)
Desc =		Optional description
SO EMISFACT Description		Scalar/Variable emissions description

EXAMPLE

Permit	AERMOD	Pollutant	Averaging time	Operating scenario	Scalar/Variable emissions_type	X1	Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	Length_X	Length_Y	Rotation_Angle	sigma z	Description
ID	ID					[m]	[m]	[m]	(g/sec/m^2)	(lb/hr/ft^2)	[m]	[m]	[m]	[deg]	[m]	
FS001	FACCONCWE	PM10	24-hr	2		483,070.730	5,247,239.030	469.24	1		0	200	500	0		parking lot
FS002	FACOXPILE	PM2.5	24-hr	1	WSPEED	483,070.730	5,247,239.030	469.24	0.00000536		0	50	100	0		talings basin

Permit	AERMOD	Pollutant	Averaging time	Operating scenario	Scalar/Variable emissions_type	X1	Y1	Base_Elev	Emission_Rate	Emission_Rate	Height	Length_X	Length_Y	Rotation_Angle	Number of Vertices	Description
ID	ID			#		[m]	[m]	[m]	(g/sec/m^2)	(lb/hr/ft^2)	[m]	[m]	[m]	[deg]		
FS001 FS002	AGCFS001_2	PM2.5	24-hour; Annual	NAAQS		462,917.550	4,960,556.480	224.87	1.71E-07	1.26E-07	6.096				5	Nearby Source - Anchor Glass (No FS or FUGI listed in air permit. Assume these sources are raw material stockpiles containing sand, soda-ash, feldspar, aragonite and cullet)
FUGI13	AGCFUG13	PM2.5	24-hour; Annual	NAAQS		463,010.000	4,960,535.140	225.1	8.00E-06	5.90E-06	6.096				4	Nearby Source - Anchor Glass (No FS or FUGI listed in air permit. Assume these sources are raw material stockpiles containing sand, soda-ash, feldspar, aragonite and cullet)

VOC emissions from vertical, fixed roof tank #1

Enter tank specific information in all blue cells.

Tank information

Tank identification	Diesel Tank #1
Description	Diesel Tank #1
Location (city)	Shakopee, MN

Property	Value	Units	Description
Fuel type	Diesel	select one	Type of fuel stored in the tank.
Type of roof	Dome	select one	Fixed roof structure.
Actual throughput	7,500,582	gal/yr	Gallons stored in his tank over the period of 12 consecutive months.
Actual hours operated	8760	hours/year	Number of hours the tank is being used.
Potential throughput	9,750,757	gal/yr	Calculated based on actual tank throughput divided by the hours operated and multiplied by 8760 hours/day.
VOC actual emissions	**0.03**	ton/yr	Amount of VOC actually released over the 12-month period.
VOC potential emissions	**0.03**	ton/yr	Amount of VOCs potentially released over a 12-month period.

Physical properties of the tank

Property		Value	Units	Description
Shell height	H_S	40	feet	This is actual length of the tank.
Shell diameter	D	21	feet	This is the width of the cylindrical shell.
Shell radius	R_S	10.5	feet	Calculated radius
Maximum liquid height	H_{LX}	37	feet	Maximum height of the liquid within the tank shell.
Average liquid height	H_L	18.5	feet	Average height of the liquid within the tank shell.
Working volume		95858.8	gallons	Calculated volume
Turnovers per year (actual)	N	78.2	dimensionless	Calculated number the tank is emptied and refilled, annually.
Turnovers per year (potential)	N	101.7	dimensionless	Calculated number the tank could be emptied and refilled, annually.
Shell color/shade		White/NA	select one	Tank shell color and shade are used to identify **paint solar absorptance**.
Shell condition		Average	select one	Tank condition is used to identify **paint solar absorptance**.
Paint solar absorptance	α	0.25	dimensionless	**Insert value from table 7.1-6.** Paint effectiveness in absorbing radiant energy.
Roof height	H_R	3.69	feet	Calculated roof height.
Dome roof radius	R_R	16.80	feet	Calculated radius. Only applies to a "Dome" roof.
Cone roof slope	S_R	--	ft/ft	If unknown = 0.0625. If known, insert value. Only applies to a "Cone" roof.
Vacuum setting	P_{BV}	-0.03	psig	Vacuum setting is a value set for the tank at the facility.
Pressure setting	P_{BP}	0.03	psig	Breather vent pressure is a reading from the tank monitoring system.

Weather data

Property		Value	Units	Description
Nearest major city		Minneapolis - St. Paul	Select one	Nearest major city to the tank location.
Average annual maximum temperature	T_{AX}	54.2	°F	Average over a calendar year.
Average annual minimum temperature	T_{AN}	35.2	°F	Average over a calendar year.
Atmospheric pressure	P_A	14.26	psia	Average for the location.
Solar insolation	I	1170.00	Btu/(ft^2·day)	Total for a horizontal surface.

Calculation of VOC Emission = Total Losses (L_T)

Variable		Calculated value		Notes (equations are from AP-42, Chapter 7)
Total losses (VOC actual emissions)	L_T	**64.26**	lb/yr	Equation 1-1
Total losses (VOC potential emissions)	L_T	**69.21**	lb/yr	Equation 1-1
Standing storage losses	L_S	9.80	lb/yr	Equation 1-2
Working losses (actual)	L_W	54.46	lb/yr	Equation 1-35
Working losses (potential)	L_W	59.41	lb/yr	Equation 1-35
Annual net throughput (actual)	Q	178585.29	bbl/yr	Based on actual throughput entered by user (gal/year) / 42 bbl/gal
Annual net throughput (potential)	Q	232160.87	bbl/yr	Based on calculated potential throughput (gal/year) / 42 bbl/gal
Working loss turnover factor (actual)	K_N	0.55	dimensionless	Saturation; turnovers >36 = (180 + N) / 6 * N; turnovers at 36 or lower = 1; Equation 1-
Working loss turnover factor (potential)	K_N	0.46	dimensionless	Saturation; turnovers >36 = (180 + N) / 6 * N; turnovers at 36 or lower = 1
Stock vapor density	W_V	0.00	lb/ft^3	Equation 1-22
Vapor Molecular Weight at 60 °F	M_V	130	lb/lb-mole	Table 7.1-2
Vapor pressure at 60 °F	P_{VA}	0.004135096	psia	Equation 1-25, P_{VA} based on T_{LA}
Vapor space volume	V_V	8111.22	ft^3	Equation 1-3
Vapor space roof outage	H_{RO}	1.92	feet	Equation 1-17 Cone; Equation 1-19 Dome
Vapor space tank outage	H_{VO}	23.42	feet	Equation 1-16, vertical
Vapor space expansion factor	K_E	0.03		Equation 1-5
Vented vapor saturation factor	K_S	0.99	dimensionless	Equation 1-21
Working loss product factor	K_P	1	dimensionless	Assume value of 1 for gasoline or diesel.
Ideal gas constant	R	10.731	psia*ft^3/lb-mole*°R	Constant, Equation 1-22
Average vapor temperature	T_V	507.30	°R	Equation 1-33
Daily average liquid surface temperature	T_{LA}	506.39	°R	Equation 1-28
Daily vapor temperature range	ΔT_V	19.15	°R	Equation 1-7
Daily ambient temperature range	ΔT_A	19.00	°R	Equation 1-11
Daily maximum ambient temperature	T_{AX}	513.90	°R	Table 7-1-7. Conversion factor: Rankine = Fahrenheit + 459.7
Daily minimum ambient temperature	T_{AN}	494.90	°R	Table 7-1-7. Conversion factor: Rankine = Fahrenheit + 459.7
Daily average ambient temperature	T_{AA}	504.40	°R	Equation 1-30
Liquid bulk temperature	T_B	505.28	°R	Equation 1-31
Daily vapor pressure range	ΔP_V	0.00	psia	Equation 1-9
Breather vent pressure setting range	ΔP_B	0.06	psi	Equation 1-10
Vapor pressure equation constant	A	12.101	dimensionless	Table 7.1-2

VOC emissions from vertical, fixed roof tank #1

Enter tank specific information in all blue cells.

Tank information

Tank identification	Diesel Tank #2
Description	Diesel Tank #2
Location (city)	Shakopee, MN

Property	Value	Units	Description
Fuel type	Diesel	select one	Type of fuel stored in the tank.
Type of roof	Dome	select one	Fixed roof structure.
Actual throughput	7,500,582	gal/yr	Gallons stored in his tank over the period of 12 consecutive months.
Actual hours operated	8760	hours/year	Number of hours the tank is being used.
Potential throughput	9,750,757	gal/yr	Calculated based on actual tank throughput divided by the hours operated and multiplied by 8760 hours/day.
VOC actual emissions	**0.03**	ton/yr	Amount of VOC actually released over the 12-month period.
VOC potential emissions	**0.03**	ton/yr	Amount of VOCs potentially released over a 12-month period.

Physical properties of the tank

Property		Value	Units	Description
Shell height	H_S	40	feet	This is actual length of the tank.
Shell diameter	D	21	feet	This is the width of the cylindrical shell.
Shell radius	R_S	10.5	feet	Calculated radius
Maximum liquid height	H_{LX}	37	feet	Maximum height of the liquid within the tank shell.
Average liquid height	H_L	18.5	feet	Average height of the liquid within the tank shell.
Working volume		95858.8	gallons	Calculated volume
Turnovers per year (actual)	N	78.2	dimensionless	Calculated number the tank is emptied and refilled, annually.
Turnovers per year (potential)	N	101.7	dimensionless	Calculated number the tank could be emptied and refilled, annually.
Shell color/shade		White/NA	select one	Tank shell color and shade are used to identify **paint solar absorptance**.
Shell condition		Average	select one	Tank condition is used to identify **paint solar absorptance**.
Paint solar absorptance	α	0.25	dimensionless	**Insert value from table 7.1-6.** Paint effectiveness in absorbing radiant energy.
Roof height	H_R	3.69	feet	Calculated roof height.
Dome roof radius	R_R	16.80	feet	Calculated radius. Only applies to a "Dome" roof.
Cone roof slope	S_R	--	ft/ft	If unknown = 0.0625. If known, insert value. Only applies to a "Cone" roof.
Vacuum setting	P_{BV}	-0.03	psig	Vacuum setting is a value set for the tank at the facility.
Pressure setting	P_{BP}	0.03	psig	Breather vent pressure is a reading from the tank monitoring system.

Weather data

Property		Value	Units	Description
Nearest major city		Minneapolis - St. Paul	Select one	Nearest major city to the tank location.
Average annual maximum temperature	T_{AX}	54.2	°F	Average over a calendar year.
Average annual minimum temperature	T_{AN}	35.2	°F	Average over a calendar year.
Atmospheric pressure	P_A	14.26	psia	Average for the location.
Solar insolation	I	1170.00	Btu/(ft^2·day)	Total for a horizontal surface.

Calculation of VOC Emission = Total Losses (L_T)

Variable		Calculated value		Notes (equations are from AP-42, Chapter 7)
Total losses (VOC actual emissions)	L_T	**64.26**	lb/yr	Equation 1-1
Total losses (VOC potential emissions)	L_T	**69.21**	lb/yr	Equation 1-1
Standing storage losses	L_S	9.80	lb/yr	Equation 1-2
Working losses (actual)	L_W	54.46	lb/yr	Equation 1-35
Working losses (potential)	L_W	59.41	lb/yr	Equation 1-35
Annual net throughput (actual)	Q	178585.29	bbl/yr	Based on actual throughput entered by user (gal/year) / 42 bbl/gal
Annual net throughput (potential)	Q	232160.87	bbl/yr	Based on calculated potential throughput (gal/year) / 42 bbl/gal
Working loss turnover factor (actual)	K_N	0.55	dimensionless	Saturation; turnovers >36 = (180 + N) / 6 * N; turnovers at 36 or lower = 1; Equation 1-
Working loss turnover factor (potential)	K_N	0.46	dimensionless	Saturation; turnovers >36 = (180 + N) / 6 * N; turnovers at 36 or lower = 1
Stock vapor density	W_V	0.00	lb/ft^3	Equation 1-22
Vapor Molecular Weight at 60 °F	M_V	130	lb/lb-mole	Table 7.1-2
Vapor pressure at 60 °F	P_{VA}	0.004135096	psia	Equation 1-25, P_{VA} based on T_{LA}
Vapor space volume	V_V	8111.22	ft^3	Equation 1-3
Vapor space roof outage	H_{RO}	1.92	feet	Equation 1-17 Cone; Equation 1-19 Dome
Vapor space tank outage	H_{VO}	23.42	feet	Equation 1-16, vertical
Vapor space expansion factor	K_E	0.03		Equation 1-5
Vented vapor saturation factor	K_S	0.99	dimensionless	Equation 1-21
Working loss product factor	K_P	1	dimensionless	Assume value of 1 for gasoline or diesel.
Ideal gas constant	R	10.731	psia*ft^3/lb-mole*°R	Constant, Equation 1-22
Average vapor temperature	T_V	507.30	°R	Equation 1-33
Daily average liquid surface temperature	T_{LA}	506.39	°R	Equation 1-28
Daily vapor temperature range	ΔT_V	19.15	°R	Equation 1-7
Daily ambient temperature range	ΔT_A	19.00	°R	Equation 1-11
Daily maximum ambient temperature	T_{AX}	513.90	°R	Table 7-1-7. Conversion factor: Rankine = Fahrenheit + 459.7
Daily minimum ambient temperature	T_{AN}	494.90	°R	Table 7-1-7. Conversion factor: Rankine = Fahrenheit + 459.7
Daily average ambient temperature	T_{AA}	504.40	°R	Equation 1-30
Liquid bulk temperature	T_B	505.28	°R	Equation 1-31
Daily vapor pressure range	ΔP_V	0.00	psia	Equation 1-9
Breather vent pressure setting range	ΔP_B	0.06	psi	Equation 1-10
Vapor pressure equation constant	A	12.101	dimensionless	Table 7.1-2

VOC emission summary for vertical, fixed roof tanks

	VOC actual emissions (tons/year)	VOC potential emissions (tons/year)
Vertical tank 1	0.03	0.03
Vertical tank 2	0.03	0.03
Vertical tanks total	**0.06**	**0.07**

If there are more than 3 vertical tanks at the facility, you can copy/duplicate a blue tank tab:

i. Right-click on the tab name (example 'Vertical tank 3')
ii. Select 'Move or Copy'
iii. Check to box next to 'Create a Copy'

Step	# events	Duration per event (hours)	Total Duration (hours)	Load	Notes
Manufacturer Recommended Initial Start-Up Process (Including commissioning and Burn-in)					
Starts to Full Speed - No Load	25	0.1	2.1	No load	Test all safety protection functions and intial fuel control/safety validiation
Burn-in Run	1	6	6.0	Up to 100%	4-6 hours operating from no load up to full load - uncontrolled Bring entire system up to temp to eliminate catalyst damaging contaminants No catalyst, no urea

Emission Calculations

Pollutant	Cold Starts[a]	Burn in Run[b]					Total Emissions during Burn-In Per Engine	Total Emissions for Burn-In for all Engines	Normal Operation	Equivalent Time in Normal Operation
	Cold Start Emissions (tons)	Low Load Emissions (tons)	40% Load Emissions (tons)	75% Load Emissions (tons)	100% Load Emissions (tons)	Total (tons)	tons	tons	lb/hr	hrs
NOx	9.38E-02	8.50E-01	5.74E-02	1.13E-01	1.95E-01	1.22E+00	1.31	3.93	10.86	241
CO	2.19E-02	2.07E-01	2.13E-02	3.79E-02	4.36E-02	3.10E-01	0.33	0.99	3.78	175
VOC	6.71E-03	5.06E-02	5.96E-03	1.11E-02	1.43E-02	8.20E-02	0.09	0.27	4.33	41
$PM/PM_{10}/PM_{2.5}$ (total)	1.04E-02	5.95E-03	1.96E-03	2.57E-03	3.40E-03	1.39E-02	2.43E-02	0.07	4.76	10
SO_2	2.51E-04	9.04E-05	9.04E-05	9.04E-05	9.04E-05	3.62E-04	6.13E-04	0.00	0.12	10
CO_2	13.33	8.27			8.27	1.65E+01		89.64		
CH_4		3.95E-04			3.95E-04	7.90E-04		0.00		
NO_2		7.90E-05			7.90E-05	1.58E-04		0.00		
CO_2e		8.31			8.31	1.66E+01		49.85		

(a) The 5 minute starts are considered cold-starts for the purpose of these calculations

(b) The NOx, CO, and VOC emission factors have been adjusted to reflect the absense of control devices and their respective control efficiencies.

Fuel Oil Start-up/Shutdown

Component	Emissions per Start[A]	Emissions per Shutdown[B]
	lb	lb
NOx	45.0	0.20
CO	10.5	0.10
VOC as CH4 equivalent	3.2	0.10
PM/PM10/PM2.5 (total)	5.0	0.05
SO2	0.12	0.004
CO2	6,398	213.00

Control Efficiencies				
Pollutant	100% Load	75% Load	50% Load	Method
NOx	0.96	0.95	0.93	SCR
CO	0.94	0.94	0.94	Oxidation Catalyst
VOC	0.77	0.78	0.76	Oxidation Catalyst

Emission Calculations

Pollutant	lb/hr per engine			
	FO Low Load	FO 100%	FO 75%	FO 40%
NO_x	79.37	10.86	8.22	5.36
CO	15.87	3.35	2.86	1.63
VOC	15.87	4.33	3.28	1.87
VOC (without gas fluctuations)	15.87	4.33	3.28	1.87
$PM/PM_{10}/PM_{2.5}$ (total)	7.94	4.53	3.43	2.61
SO_2[4]	0.12	0.12	0.12	0.12
CO_2[5]	11,033	11,033		
CH_4[5]	0.53	0.53		
NO_2[5]	0.11	0.11		
CO_2e[6]	11,077	11,077		

Attachment 2 - Subject Item Inventory and Requirements Report

SI List

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	
Activity	Insignificant Air Emissions Activity	ACTV 1	Null	All IAs	
Agency Interest	Conventional Site	AISI 1860	Null	Null	
Component Group	Air Component Group	COMG 2	GP002	NG-Fired GE 7FA Combustion Turbines	
		COMG 4	GP003	NOx CEMS for EQUI 7 and EQUI 8	
		COMG 5	GP005	HAPs Limits	
		COMG 7	Null	CO CEMS for EQUI 7 and EQUI 8	
		COMG 8	Null	Transport Rule/CSAPR for EQUI 1 through 4 and NG CTs EQUI 7 and 8	
		COMG 9	Null	O2 CEMS for EQUI 7 and EQUI 8	
Equipment	Aboveground Storage Tank	EQUI 32	Null	Diesel Tank #1	
		EQUI 33	Null	Diesel Tank #2	
	Continuous Emission Monitor	EQUI 9	MR001	NOx CEMS for EQUI 7	
		EQUI 10	MR002	CO CEMS for EQUI 7	
		EQUI 11	MR003	NOx CEMS for EQUI 8	
		EQUI 12	MR004	CO CEMS for EQUI 8	
		EQUI 30	Null	EQUI 7 O2 CEMS (diluent)	
		EQUI 31	Null	EQUI 8 O2 CEMS (diluent)	
	Data Acquisition System	EQUI 16	Null	Stackvision Data Acquisition System	
	Parametric Monitor	EQUI 21	Null	Fuel usage parametric monitor for EQUI 7	
		EQUI 22	Null	Fuel usage parametric monitor for EQUI 8	
		EQUI 34	Null	EQUI 23 SCR and Oxidation Catalyst Inlet Temperature	
		EQUI 35	Null	EQUI 23 SCR and Oxidation Catalyst Inlet Pressure	
		EQUI 36	Null	EQUI 23 SCR and Oxidation Catalyst Outlet Pressure	
		EQUI 37	Null	EQUI 24 SCR and Oxidation Catalyst Inlet Temperature	
		EQUI 38	Null	EQUI 24 SCR and Oxidation Catalyst Inlet Pressure	
		EQUI 39	Null	EQUI 24 SCR and Oxidation Catalyst Outlet Pressure	
		EQUI 40	Null	EQUI 25 SCR and Oxidation Catalyst Inlet Temperature	
		EQUI 41	Null	EQUI 25 SCR and Oxidation Catalyst Inlet Pressure	
		EQUI 42	Null	EQUI 25 SCR and Oxidation Catalyst Outlet Pressure	
	Reciprocating IC Engine	EQUI 5	EU005	Emergency Engine/Generator	
		EQUI 23	Null	Engine Generator 1	
		EQUI 24	Null	Engine Generator 2	
		EQUI 25	Null	Engine Generator 3	
		EQUI 26	Null	Emergency Generator 2	
		EQUI 27	Null	Emergency Generator 3	
		EQUI 28	Null	Emergency Generator 4	
		EQUI 29	Null	Emergency Generator 5	
		EQUI 43	Null	Emergency Generator 6	
	Turbine	EQUI 1	EU001	Combustion Turbine 1 (50 MW) - Turbine	
		EQUI 2	EU002	Combustion Turbine 2 (50 MW) - Turbine	
		EQUI 3	EU003	Combustion Turbine 3 (50 MW) - Turbine	
		EQUI 4	EU004	Combustion Turbine 4 (55 MW) - Turbine	
		EQUI 7	EU007	GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	
		EQUI 8	EU008	GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	
Fugitive	Paved Road	FUGI 1	Null	Engine generator fuel deliveries on paved road	
Structure	Building	STRU 1	BG002	Substation Generator Building	
		STRU 2	BG003	Foam House	
		STRU 3	BG004	Gas Turbine Building	
		STRU 4	BG005	Operations Building	
		STRU 5	BG006	Fuel Forwarding Building	
		STRU 6	BG007	Fire Foam Equipment Building	
		STRU 7	BG008	Fuel Oil Tank	
		STRU 8	BG009	Fuel Oil Tank	
		STRU 9	BG010	Warehouse	
		STRU 10	BG011	Gas Turbine 7 Structure	
		STRU 11	BG012	Gas Turbine 8 Structure	
		STRU 20	BG001	Substation controls building	
		STRU 31	Null	Rice #1 Equipment	
		STRU 32	Null	Rice #2 Equipment	
		STRU 33	Null	Rice #3 Equipment	
		STRU 34	Null	Rice Building Tier 1	
		STRU 35	Null	Rice Building Tier 2	
		STRU 36	Null	West Fuel Oil Tank #1	
		STRU 37	Null	West Fuel Oil Tank #2	
	Stack/Vent	STRU 12	SV007	Combustion Turbine 7 (EQUI 7)	
		STRU 13	SV008	Combustion Turbine 8 (EQUI 8)	
		STRU 14	SV005	Substation engine/generator stack	
		STRU 16	SV001	Combustion Turbine 1	
		STRU 17	SV002	Combustion Turbine 2	
		STRU 18	SV003	Combustion Turbine 3	
		STRU 19	SV004	Combustion Turbine 4	
		STRU 24	Null	EQUI 23 Stack	
		STRU 25	Null	EQUI 24 Stack	
		STRU 26	Null	EQUI 25 Stack	

SI List

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	
Structure	Stack/Vent	STRU 27	Null	EQUI 26 Stack	
		STRU 28	Null	EQUI 27 Stack	
		STRU 29	Null	EQUI 28 Stack	
		STRU 30	Null	EQUI 29 Stack	
		STRU 38	Null	EQUI 43 Stack	
Total Facility	Air Quality Total Facility	TFAC 1	13900010	Xcel Energy - Blue Lake	
Treatment	139-SCR (Selective Catalytic Reduction)	TREA 2	Null	Selective Catalytic Reduction	
		TREA 4	Null	Selective Catalytic Reduction	
		TREA 6	Null	Selective Catalytic Reduction	
	312-Oxidation Catalyst	TREA 1	Null	Oxidation Catalyst	
		TREA 3	Null	Oxidation Catalyst	
		TREA 5	Null	Oxidation Catalyst	

Insignificant Activities

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Status Description	Sub Attribute Description	
Activity	Insignificant Air Emissions Activity	Active / Existing	Minn. R. 7007.1300, subp. 3(A)	
			Minn. R. 7007.1300, subp. 3(E)	
			Minn. R. 7007.1300, subp. 4	
			Minn. R. 7008.4100	
			Minn. R. 7008.4110	

Emission Units 1

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Type	Subject Item ID	Delta Designation	Description	Manufacturer	Model	Max Design Capacity	Max Design Capacity Units	Material	Firing Method	Subject to CSAPR?	Electric Generating Capacity (MW)	Construction Start Date	Operation Start Date	Modification Date	
Turbine	EQUI 1	EU001	Combustion Turbine 1 (50 MW) - Turbine	Turbodyne	Megapack GT-55	50	megawatts/hours	Electrical Energy	Null	Null	Null	1/1/1974	1/1/1974	Null	
	EQUI 2	EU002	Combustion Turbine 2 (50 MW) - Turbine	Turbodyne	Megapack GT-55	50	megawatts/hours	Electrical Energy	Null	Null	Null	1/1/1974	1/1/1974	Null	
	EQUI 3	EU003	Combustion Turbine 3 (50 MW) - Turbine	Turbodyne	Megapack GT-55	50	megawatts/hours	Electrical Energy	Null	Null	Null	1/1/1974	1/1/1974	Null	
	EQUI 4	EU004	Combustion Turbine 4 (55 MW) - Turbine	Turbodyne	Megapack GT-55	55	megawatts/hours	Electrical Energy	Null	Null	Null	1/1/1974	1/1/1974	Null	
	EQUI 7	EU007	GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	General Electric	7F	174.1	megawatts/hours	Electrical Energy	Null	Null	Null	5/1/2004	5/15/2004	Null	
	EQUI 8	EU008	GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	General Electric	7F	174.1	megawatts/hours	Electrical Energy	Null	Null	Null	5/1/2004	5/31/2004	Null	

Emission Units 2

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Type	Subject Item ID	Delta Designation	Description	Manufacturer	Model	Max Design Capacity	Max Design Capacity Units	Material	Engine Use	Firing Method	Engine Displacement	Engine Displacement Units	Construction Start Date	Operation Start Date	Modification Date	
Reciprocating IC Engine	EQUI 5	EU005	Emergency Engine/ Generator	Caterpillar	3304	157	horsepower/each	Electrical Energy	Emergency/blacks..	CI	1.7	liters per cylinder	8/1/1993	8/1/1993	Null	
	EQUI 23	Null	Engine Generator 1	Wartsila	20V34DF	77.7	million British thermal units/hours	Fuel	Unlimited use	CI	36.3	liters per cylinder	4/1/2024	4/1/2024	Null	
	EQUI 24	Null	Engine Generator 2	Wartsila	20V34DF	77.7	million British thermal units/hours	Fuel	Unlimited use	CI	36.3	liters per cylinder	4/1/2024	4/1/2024	Null	
	EQUI 25	Null	Engine Generator 3	Wartsila	20V34DF	77.7	million British thermal units/hours	Fuel	Unlimited use	CI	36.3	liters per cylinder	4/1/2024	4/1/2024	Null	
	EQUI 26	Null	Emergency Generator 2	CAT	C18 750 kW	7.59	million British thermal units/hours	Fuel	Emergency/blacks..	CI	3	liters per cylinder	TBD	TBD	Null	
	EQUI 27	Null	Emergency Generator 3	CAT	C18 750 kW	7.59	million British thermal units/hours	Fuel	Emergency/blacks..	CI	3	liters per cylinder	TBD	TBD	Null	
	EQUI 28	Null	Emergency Generator 4	CAT	C18 750 kW	7.59	million British thermal units/hours	Fuel	Emergency/blacks..	CI	3	liters per cylinder	TBD	TBD	Null	
	EQUI 29	Null	Emergency Generator 5	CAT	C18 550 kW	5.59	million British thermal units/hours	Fuel	Emergency/blacks..	CI	3	liters per cylinder	TBD	TBD	Null	
	EQUI 43	Null	Emergency Generator 6	CAT	C18 550 kW	5.59	million British thermal units/hours	Fuel	Emergency/blacks..	CI	3	liters per cylinder	TBD	TBD	Null	

Component Groups

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item ID	Delta Designation	Description	Group Member ID	
COMG 2	GP002	NG-Fired GE 7FA Combustion Turbines	EQUI 7	
			EQUI 8	
COMG 4	GP003	NOx CEMS for EQUI 7 and EQUI 8	EQUI 9	
			EQUI 11	
COMG 5	GP005	HAPs Limits	EQUI 1	
			EQUI 2	
			EQUI 3	
			EQUI 4	
			EQUI 7	
			EQUI 8	
			EQUI 23	
			EQUI 24	
			EQUI 25	
			EQUI 26	
			EQUI 27	
			EQUI 28	
			EQUI 29	
			EQUI 43	
COMG 7	Null	CO CEMS for EQUI 7 and EQUI 8	EQUI 10	
			EQUI 12	
COMG 8	Null	Transport Rule/CSAPR for EQUI 1 through 4 and NG CTs EQUI 7 and 8	EQUI 1	
			EQUI 2	
			EQUI 3	
			EQUI 4	
			EQUI 7	
			EQUI 8	
COMG 9	Null	O2 CEMS for EQUI 7 and EQUI 8	EQUI 30	
			EQUI 31	

PTE by SI

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Pollutant	Potential (lbs/hr)	Unrestricted Potential (tons/yr)	Potential Limited (tons/yr)	Actual Emissions (tons/yr)
Component Group	Air Component Group	COMG 2	GP002	NG-Fired GE 7FA Combust..	Carbon Monoxide	0	0	310.8	
		COMG 5	GP005	HAPs Limits	HAPs - Single			9	
					HAPs - Total			22.5	
Equipment	Aboveground Storage Tank	EQUI 32	Null	Diesel Tank #1	Volatile Organic Compounds	0.007	0.03	0.03	
		EQUI 33	Null	Diesel Tank #2	Volatile Organic Compounds	0.007	0.03	0.03	
	Reciprocating IC Engine	EQUI 5	EU005	Emergency Engine/Generator	1,3-Butadiene	4.3e-05	0.000188	1.08e-05	
					Acetaldehyde	0.000844	0.0037	0.000211	
					Acrolein	0.000102	0.000446	2.54e-05	
					Benzene	0.00103	0.0045	0.000257	
					Carbon Dioxide	179	786	44.84	
					Carbon Dioxide Equivalent	180	788	45	
					Carbon Monoxide	1.05	4.58	0.261	
					Formaldehyde	0.0013	0.00569	0.000325	
					Methane	0.00728	0.0319	0.00182	
					Naphthalene	9.33e-05	0.000409	2.33e-05	
					Nitrogen Oxides	4.85	21.2	1.21	
					Nitrous Oxide	0.00146	0.00637	0.000364	
					Particulate Matter	0.341	1.49	0.0853	
					PM < 2.5 micron	0.341	1.49	0.0853	
					PM < 10 micron	0.341	1.49	0.0853	
					Propylene oxide	0.00284	0.0124	0.00071	
					Sulfur Dioxide	0.00165	0.00723	0.000413	
					Toluene	0.00045	0.00197	0.000112	
					Volatile Organic Compounds	0.385	1.69	0.0963	
					Xylenes, Total	0.000314	0.001373	7.84e-05	
		EQUI 23	Null	Engine Generator 1	1,1-Dichloroethane	0.00183	0.00803	0.00803	
					1,1,2-Trichloroethane	0.00247	0.0108	0.0108	
					1,1,2,2-Tetrachloroethane	0.00311	0.0136	0.0136	
					1,2-Dibromoethane (Ethylene dibromide); EDB	0.00344	0.0151	0.0151	
					1,2-Dichloroethane	0.00183	0.00803	0.00803	
					1,2-Dichloropropane	0.00209	0.00915	0.00915	
					1,2,4-Trimethylbenzene	0.00111	0.00487	0.00487	
					1,3-Butadiene	0.0207	0.0909	0.0909	
					1,3-Dichloropropene	0.00205	0.00898	0.00898	
					2-Methylnaphthalene	0.00258	0.0113	0.0113	
					Acenaphthene	9.71e-05	0.000425	0.000425	
					Acenaphthylene	0.00043	0.00188	0.00188	
					Acetaldehyde	0.65	2.85	2.85	
					Acrolein	0.399	1.75	1.75	
					Benzene	0.0618	0.271	0.271	
					Benzo(b)fluoranthene	1.29e-05	5.65e-05	5.65e-05	
					Benzo(e)pyrene	3.22e-05	0.000141	0.000141	
					Benzo(ghi)perylene	3.22e-05	0.000141	0.000141	
					Biphenyl	0.0165	0.0721	0.0721	
					Carbon Dioxide	16,540	72,445.2	72,445.2	
					Carbon Dioxide Equivalent	16,584	72,640	72,640	
					Carbon Monoxide	3.78	20	20	
					Carbon tetrachloride	0.00285	0.0125	0.0125	
					Chlorobenzene (Monochlorobenzene)	0.00236	0.0103	0.0103	
					Chloroethane	0.000145	0.000636	0.000636	
					Dichloromethane (Methylene chloride)	0.00155	0.00681	0.00681	
					Ethylbenzene	0.00308	0.0135	0.0135	
					Fluoranthene	8.62e-05	0.000378	0.000378	
					Fluorene	0.000441	0.00193	0.00193	
					Formaldehyde	0.000441	1.1	1.1	
					Hexane	0.0862	0.378	0.378	
					Methane	0.53	2.31	2.31	
					Methanol	0.194	0.851	0.851	
					Naphthalene	0.0103	0.0453	0.0453	
					Nitrogen Oxides	10.86	63.32	63.32	
					Nitrous Oxide	0.11	0.46	0.46	
					Particulate Matter	4.78	20.92	20.92	
					Phenanthrene	0.000808	0.00354	0.00354	
					Phenol	0.00186	0.00817	0.00817	
					PM < 2.5 micron	4.78	20.92	20.92	
					PM < 10 micron	4.78	20.92	20.92	
					Pyrene	0.000106	0.000463	0.000463	
					Styrene	0.00183	0.00803	0.00803	
					Sulfur Dioxide	0.12059	0.53	0.53	
					Toluene	0.0317	0.139	0.139	
					Total Polycyclic aromatic hydrocarbons	0.0169	0.0739	0.0739	
					Vinyl chloride (chloroethene)	0.00116	0.00507	0.00507	
					Volatile Organic Compounds	4.33	19.4	19.4	
					Xylenes, Total	0.0143	0.0626	0.0626	
		EQUI 24	Null	Engine Generator 2	1,1-Dichloroethane	0.00183	0.00803	0.00803	

PTE by SI

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Pollutant	Potential (lbs/hr)	Unrestricted Potential (tons/yr)	Potential Limited (tons/yr)	Actual Emissions (tons/yr)
Equipment	Reciprocating IC Engine	EQUI 24	Null	Engine Generator 2	1,1,2-Trichloroethane	0.00247	0.0108	0.0108	
					1,1,2,2-Tetrachloroethane	0.00311	0.0136	0.0136	
					1,2-Dibromoethane (Ethylene dibromide); EDB	0.00344	0.0151	0.0151	
					1,2-Dichloroethane	0.00183	0.00803	0.00803	
					1,2-Dichloropropane	0.00209	0.00915	0.00915	
					1,2,4-Trimethylbenzene	0.00111	0.00487	0.00487	
					1,3-Butadiene	0.0207	0.0909	0.0909	
					1,3-Dichloropropene	0.00205	0.00898	0.00898	
					2-Methylnaphthalene	0.00258	0.0113	0.0113	
					Acenaphthene	9.71e-05	0.000425	0.000425	
					Acenaphthylene	0.00043	0.00188	0.00188	
					Acetaldehyde	0.00201	0.00879	0.00879	
					Acrolein	0.399	1.75	1.75	
					Benzene	0.0342	0.15	0.15	
					Benzo(b)fluoranthene	1.29e-05	5.65e-05	5.65e-05	
					Benzo(e)pyrene	3.22e-05	0.000141	0.000141	
					Benzo(ghi)perylene	3.22e-05	0.000141	0.000141	
					Biphenyl	0.0165	0.0721	0.0721	
					Carbon Dioxide	16,500	72,400	72,400	
					Carbon Dioxide Equivalent	16,540	72,445	72,445	
					Carbon Monoxide	3.78	20	20	
					Carbon tetrachloride	0.00285	0.0125	0.0125	
					Chlorobenzene (Monochlorobenzene)	0.00236	0.0103	0.0103	
					Chloroethane	0.000145	0.000636	0.000636	
					Chloroform	0.00221	0.0097	0.0097	
					Dichloromethane (Methylene chloride)	0.00155	0.00681	0.00681	
					Ethylbenzene	0.00308	0.0135	0.0135	
					Fluoranthene	8.62e-05	0.000378	0.000378	
					Fluorene	0.000441	0.00193	0.00193	
					Formaldehyde	0.252	1.1	1.1	
					Hexane	0.0862	0.378	0.378	
					Methane	0.526	2.31	2.31	
					Methanol	0.194	0.851	0.851	
					Naphthalene	0.0103	0.0453	0.0453	
					Nitrogen Oxides	10.9	63.3	63.3	
					Nitrous Oxide	0.105	0.461	0.461	
					Particulate Matter	4.78	20.92	20.92	
					Phenanthrene	0.000808	0.00354	0.00354	
					Phenol	0.00186	0.00817	0.00817	
					PM < 2.5 micron	4.78	20.92	20.92	
					PM < 10 micron	4.78	20.92	20.92	
					Pyrene	0.000106	0.000463	0.000463	
					Styrene	0.00183	0.00803	0.00803	
					Sulfur Dioxide	0.121	0.528	0.528	
					Toluene	0.0224	0.098	0.098	
					Total Polycyclic aromatic hydrocarbons	0.0169	0.0739	0.0739	
					Vinyl chloride (chloroethene)	0.00116	0.00507	0.00507	
					Volatile Organic Compounds	4.33	19.4	19.4	
					Xylenes, Total	0.0154	0.0673	0.0673	
		EQUI 25	Null	Engine Generator 3	1,1-Dichloroethane	0.00183	0.00803	0.00803	
					1,1,2-Trichloroethane	0.00247	0.0108	0.0108	
					1,1,2,2-Tetrachloroethane	0.00311	0.0136	0.0136	
					1,2-Dibromoethane (Ethylene dibromide); EDB	0.00344	0.0151	0.0151	
					1,2-Dichloroethane	0.00183	0.00803	0.00803	
					1,2-Dichloropropane	0.00209	0.00915	0.00915	
					1,2,4-Trimethylbenzene	0.00111	0.00487	0.00487	
					1,3-Butadiene	0.0207	0.0909	0.0909	
					1,3-Dichloropropene	0.00205	0.00898	0.00898	
					2-Methylnaphthalene	0.00258	0.0113	0.0113	
					Acenaphthene	9.71e-05	0.000425	0.00425	
					Acenaphthylene	0.00043	0.00188	0.00188	
					Acetaldehyde	0.65	2.85	2.85	
					Acrolein	0.399	1.75	1.75	
					Benzene	0.0618	0.271	0.271	
					Benzo(b)fluoranthene	1.29e-05	5.65e-05	5.65e-05	
					Benzo(e)pyrene	3.22e-05	0.000141	0.000141	
					Benzo(ghi)perylene	3.22e-05	0.000141	0.000141	
					Biphenyl	0.0165	0.0721	0.0721	
					Carbon Dioxide	16,540	72,445	72,445	
					Carbon Dioxide Equivalent	16,540	72,445	72,445	
					Carbon Monoxide	3.78	20	20	
					Carbon tetrachloride	0.00285	0.0125	0.0125	
					Chlorobenzene (Monochlorobenzene)	0.00236	0.0103	0.0103	
					Chloroethane	0.000145	0.000636	0.000636	
					Chloroform	0.00221	0.0097	0.0097	

PTE by SI

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Pollutant	Potential (lbs/hr)	Unrestricted Potential (tons/yr)	Potential Limited (tons/yr)	Actual Emissions (tons/yr)
Equipment	Reciprocating IC Engine	EQUI 25	Null	Engine Generator 3	Dichloromethane (Methylene chloride)	0.00155	0.00681	0.00681	
					Ethylbenzene	0.00308	0.0135	0.0135	
					Fluoranthene	8.62e-05	0.000378	0.000378	
					Fluorene	0.000441	0.00193	0.00193	
					Formaldehyde	0.252	1.1	1.1	
					Hexane	0.0862	0.378	0.378	
					Methane	0.526	2.31	2.31	
					Methanol	0.194	0.851	0.851	
					Naphthalene	0.0103	0.0453	0.0453	
					Nitrogen Oxides	10.9	63.3	63.3	
					Nitrous Oxide	0.105	0.461	0.461	
					Particulate Matter	4.78	20.92	20.92	
					Phenanthrene	0.000808	0.00354	0.00354	
					Phenol	0.00186	0.00817	0.00817	
					PM < 2.5 micron	4.78	20.92	20.92	
					PM < 10 micron	4.78	20.92	20.92	
					Pyrene	0.000106	0.000463	0.000463	
					Styrene	0.00183	0.00803	0.00803	
					Sulfur Dioxide	0.12	0.528	0.528	
					Toluene	0.0317	0.139	0.139	
					Total Polycyclic aromatic hydrocarbons	0.0169	0.0739	0.0739	
					Vinyl chloride (chloroethene)	0.00116	0.00507	0.00507	
					Volatile Organic Compounds	4.33	19.4	19.4	
					Xylenes, Total	0.0154	0.0673	0.0673	
		EQUI 26	Null	Emergency Generator 2	1,3-Butadiene	0.000986	0.000247	0.000247	
					Acetaldehyde	0.000191	4.78e-05	4.78e-05	
					Acrolein	5.98e-05	1.49e-05	1.49e-05	
					Carbon Dioxide	1,252.02	313.01	313.01	
					Carbon Dioxide Equivalent		314	314	
					Carbon Monoxide	6.03	1.51	1.51	
					Formaldehyde	0.000599	0.00015	0.00015	
					Methane	0.05	0.01	0.01	
					Naphthalene	0.000986	0.000247	0.000247	
					Nitrogen Oxides	11.03	2.76	2.76	
					Nitrous Oxide	0.01	0.003	0.003	
					Particulate Matter	0.34	0.09	0.09	
					PM < 2.5 micron	0.39	0.1	0.1	
					PM < 10 micron	0.39	0.1	0.1	
					Sulfur Dioxide	0.01	0.003	0.003	
					Toluene	0.00213	0.000533	0.000533	
					Total Polycyclic aromatic hydrocarbons	0.00161	0.000402	0.000402	
					Volatile Organic Compounds	0.68	0.17	0.17	
					Xylenes, Total	0.00146	0.000366	0.000366	
		EQUI 27	Null	Emergency Generator 3	1,3-Butadiene	0.000986	0.000247	0.000247	
					Acetaldehyde	0.000191	4.78e-05	4.78e-05	
					Acrolein	5.98e-05	1.49e-05	1.49e-05	
					Carbon Dioxide	1,252.02	313.01	313.01	
					Carbon Dioxide Equivalent		314	314	
					Carbon Monoxide	6.03	1.51	1.51	
					Formaldehyde	0.000599	0.00015	0.00015	
					Methane	0.05	0.01	0.01	
					Naphthalene	0.000986	0.000247	0.000247	
					Nitrogen Oxides	11.03	2.76	2.76	
					Nitrous Oxide	0.01	0.003	0.003	
					Particulate Matter	0.34	0.09	0.09	
					PM < 2.5 micron	0.39	0.1	0.1	
					PM < 10 micron	0.39	0.1	0.1	
					Sulfur Dioxide	0.01	0.003	0.003	
					Toluene	0.00213	0.000533	0.000533	
					Total Polycyclic aromatic hydrocarbons	0.00161	0.000402	0.000402	
					Volatile Organic Compounds	0.68	0.17	0.17	
					Xylenes, Total	0.00146	0.000366	0.000366	
		EQUI 28	Null	Emergency Generator 4	1,3-Butadiene	0.000986	0.000247	0.000247	
					Acetaldehyde	0.000191	4.78e-05	4.78e-05	
					Acrolein	5.98e-05	1.49e-05	1.49e-05	
					Carbon Dioxide	1,252.02	313.01	313.01	
					Carbon Dioxide Equivalent		314	314	
					Carbon Monoxide	6.03	1.51	1.51	
					Formaldehyde	0.000599	0.00015	0.00015	
					Methane	0.05	0.01	0.01	
					Naphthalene	0.000986	0.000247	0.000247	
					Nitrogen Oxides	11.03	2.76	2.76	
					Nitrous Oxide	0.01	0.003	0.003	
					Particulate Matter	0.34	0.09	0.09	
					PM < 2.5 micron	0.39	0.1	0.1	

PTE by SI

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Pollutant	Potential (lbs/hr)	Unrestricted Potential (tons/yr)	Potential Limited (tons/yr)	Actual Emissions (tons/yr)
Equipment	Reciprocating IC Engine	EQUI 28	Null	Emergency Generator 4	PM < 10 micron	0.39	0.1	0.1	
					Sulfur Dioxide	0.01	0.003	0.003	
					Toluene	0.00213	0.000533	0.000533	
					Total Polycyclic aromatic hydrocarbons	0.00161	0.000402	0.000402	
					Volatile Organic Compounds	0.68	0.17	0.17	
					Xylenes, Total	0.00146	0.000366	0.000366	
		EQUI 29	Null	Emergency Generator 5	1,3-Butadiene	0.000726	0.000182	0.000182	
					Acetaldehyde	0.000141	3.52e-05	3.52e-05	
					Acrolein	4.4e-05	1.1e-05	1.1e-05	
					Carbon Dioxide	921.69	230.42	230.42	
					Carbon Dioxide Equivalent		231	231	
					Carbon Monoxide	4.44	1.11	1.11	
					Formaldehyde	0.000441	0.00011	0.00011	
					Methane	0.04	0.01	0.01	
					Naphthalene	0.000726	0.000182	0.000182	
					Nitrogen Oxides	8.12	2.03	2.03	
					Nitrous Oxide	0.01	0.002	0.002	
					Particulate Matter	0.25	0.06	0.06	
					PM < 2.5 micron	0.29	0.07	0.07	
					PM < 10 micron	0.29	0.07	0.07	
					Sulfur Dioxide	0.01	0.002	0.002	
					Toluene	0.00157	0.000392	0.000392	
					Total Polycyclic aromatic hydrocarbons	0.00118	0.000296	0.000296	
					Volatile Organic Compounds	0.5	0.13	0.13	
					Xylenes, Total	0.00108	0.00027	0.00027	
		EQUI 43	Null	Emergency Generator 6	1,3-Butadiene	0.000726	0.000182	0.000182	
					Acetaldehyde	0.000141	3.52e-05	3.52e-05	
					Acrolein	4.4e-05	1.1e-05	1.1e-05	
					Carbon Dioxide	921.69	230.42	230.42	
					Carbon Dioxide Equivalent		231	231	
					Carbon Monoxide	4.44	1.11	1.11	
					Formaldehyde	0.000441	0.00011	0.00011	
					Methane	0.04	0.01	0.01	
					Naphthalene	0.000726	0.000182	0.000182	
					Nitrogen Oxides	8.12	2.03	2.03	
					Nitrous Oxide	0.01	0.002	0.002	
					Particulate Matter	0.25	0.06	0.06	
					PM < 2.5 micron	0.29	0.07	0.07	
					PM < 10 micron	0.29	0.07	0.07	
					Sulfur Dioxide	0.01	0.002	0.002	
					Toluene	0.00157	0.000392	0.000392	
					Total Polycyclic aromatic hydrocarbons	0.00118	0.000296	0.000296	
					Volatile Organic Compounds	0.5	0.13	0.13	
					Xylenes, Total	0.00108	0.00027	0.00027	
	Turbine	EQUI 1	EU001	Combustion Turbine 1 (50 MW) - Turbine	1,3-Butadiene	0.0104	0.0454	0.0454	
					Arsenic compounds	0.00713	0.0312	0.0312	
					Benzene	0.0356	0.156	0.156	
					Beryllium Compounds	0.000201	0.00088	0.00088	
					Cadmium compounds	0.00713	0.0312	0.0312	
					Carbon Dioxide	106,000	463,000	463,000	
					Carbon Dioxide Equivalent	106,000	464,000	464,000	
					Carbon Monoxide	2.14	9.37	9.37	
					Chromium compounds	0.00713	0.0312	0.0312	
					Formaldehyde	0.181	0.795	0.795	
					Lead Compounds	0.00907	0.0397	0.0397	
					Manganese compounds	0.512	2.2422	2.24	
					Mercury Compounds	0.000778	0.00341	0.00341	
					Methane	4.29	18.8	18.8	
					Naphthalene	0.0227	0.0993	0.0993	
					Nickel compounds	0.00298	0.0131	0.0131	
					Nitrogen Oxides	835	3,660	3,660	
					Nitrous Oxide	0.857	3.75	3.75	
					Particulate Matter	7.78	34.1	34.1	
					PM < 2.5 micron	7.78	34.1	34.1	
					PM < 10 micron	7.78	34.1	34.1	
					Selenium compounds	0.0162	0.071	0.071	
					Sulfur Dioxide	0.972	4.26	4.26	
					Total Polycyclic aromatic hydrocarbons	0.0259	0.114	0.114	
					Volatile Organic Compounds	0.266	1.16	1.16	
		EQUI 2	EU002	Combustion Turbine 2 (50 MW) - Turbine	1,3-Butadiene	0.0104	0.0454	0.0454	
					Arsenic compounds	0.00713	0.0312	0.0312	
					Benzene	0.0356	0.156	0.156	
					Beryllium Compounds	0.000201	0.00088	0.00088	
					Cadmium compounds	0.00311	0.0136	0.0136	
					Carbon Dioxide	106,000	463,000	463,000	

PTE by SI

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Pollutant	Potential (lbs/hr)	Unrestricted Potential (tons/yr)	Potential Limited (tons/yr)	Actual Emissions (tons/yr)
Equipment	Turbine	EQUI 2	EU002	Combustion Turbine 2 (50 MW) - Turbine	Carbon Dioxide Equivalent	106,000	464,000	464,000	
					Carbon Monoxide	2.14	9.37	9.37	
					Chromium compounds	0.00713	0.0312	0.0312	
					Formaldehyde	0.181	0.795	0.795	
					Lead Compounds	0.00907	0.0397	0.0397	
					Manganese compounds	0.512	2.2422	2.24	
					Mercury Compounds	0.000778	0.00341	0.00341	
					Methane	4.29	18.8	18.8	
					Naphthalene	0.0227	0.0993	0.0993	
					Nickel compounds	0.00298	0.0131	0.0131	
					Nitrogen Oxides	866	3,792	3,792	
					Nitrous Oxide	0.857	3.75	3.75	
					Particulate Matter	7.78	34.1	34.1	
					PM < 2.5 micron	7.78	34.1	34.1	
					PM < 10 micron	7.78	34.1	34.1	
					Selenium compounds	0.0162	0.071	0.071	
					Sulfur Dioxide	0.972	4.26	4.26	
					Total Polycyclic aromatic hydrocarbons	0.0259	0.114	0.114	
					Volatile Organic Compounds	0.266	1.16	1.16	
		EQUI 3	EU003	Combustion Turbine 3 (50 MW) - Turbine	1,3-Butadiene	0.0104	0.0454	0.0454	
					Arsenic compounds	0.00713	0.0312	0.0312	
					Benzene	0.0356	0.156	0.156	
					Beryllium Compounds	0.000201	0.00088	0.00088	
					Cadmium compounds	0.00311	0.0136	0.0136	
					Carbon Dioxide	105,658	462,781	462,781	
					Carbon Dioxide Equivalent	106,000	464,000	464,369	
					Carbon Monoxide	2.14	9.37	9.37	
					Chromium compounds	0.00713	0.0312	0.0312	
					Formaldehyde	0.181	0.795	0.795	
					Lead Compounds	0.00907	0.0397	0.0397	
					Manganese compounds	0.512	2.242	2.242	
					Mercury Compounds	0.000778	0.00341	0.00341	
					Methane	4.29	18.8	18.8	
					Naphthalene	0.0227	0.0993	0.0993	
					Nickel compounds	0.00298	0.0131	0.0131	
					Nitrogen Oxides	1,035	4,535	4,535	
					Nitrous Oxide	0.857	3.75	3.75	
					Particulate Matter	7.78	34.1	34.1	
					PM < 2.5 micron	7.78	34.1	34.06	
					PM < 10 micron	7.78	34.1	34.1	
					Selenium compounds	0.0162	0.071	0.071	
					Sulfur Dioxide	0.972	4.26	4.26	
					Total Polycyclic aromatic hydrocarbons	0.0259	0.114	0.114	
					Volatile Organic Compounds	0.266	1.16	1.16	
		EQUI 4	EU004	Combustion Turbine 4 (55 MW) - Turbine	1,3-Butadiene	0.0118	0.0519	0.0519	
					Arsenic compounds	0.00814	0.0357	0.0357	
					Benzene	0.0407	0.178	0.178	
					Beryllium Compounds	0.000229	0.001	0.001	
					Cadmium compounds	0.00355	0.0156	0.0156	
					Carbon Dioxide	121,000	528,000	528,000	
					Carbon Dioxide Equivalent	121,000	530,000	530,000	
					Carbon Monoxide	2.44	10.7	10.7	
					Chromium compounds	0.00814	0.0357	0.0357	
					Formaldehyde	0.207	0.908	0.908	
					Lead Compounds	0.0104	0.0454	0.0454	
					Manganese compounds	0.585	2.56	2.56	
					Mercury Compounds	0.000888	0.00389	0.00389	
					Methane	4.89	21.4	21.4	
					Naphthalene	0.0259	0.113	0.113	
					Nickel compounds	0.0034	0.0149	0.0149	
					Nitrogen Oxides	1,160	5,082	5,082	
					Nitrous Oxide	0.979	4.29	4.29	
					Particulate Matter	8.88	38.9	38.9	
					PM < 2.5 micron	8.88	38.9	38.9	
					PM < 10 micron	8.88	38.9	38.9	
					Selenium compounds	0.0185	0.081	0.081	
					Sulfur Dioxide	1.11	4.86	4.86	
					Total Polycyclic aromatic hydrocarbons	0.0296	0.13	0.13	
					Volatile Organic Compounds	0.303	1.33	1.33	
		EQUI 7	EU007	GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	1,3-Butadiene	0.000695	0.00304	0.00304	
					Acetaldehyde	0.0646	0.283	0.283	
					Acrolein	0.0103	0.0453	0.0453	
					Benzene	0.0194	0.0849	0.0849	
					Carbon Dioxide	224,664	984,028	984,028	
					Carbon Dioxide Equivalent	225,237	986,539	986,539	

PTE by SI

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Pollutant	Potential (lbs/hr)	Unrestricted Potential (tons/yr)	Potential Limited (tons/yr)	Actual Emissions (tons/yr)
Equipment	Turbine	EQUI 7	EU007	GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	Carbon Monoxide	38.8	196.28	0	
					Ethylbenzene	0.0517	0.226	0.226	
					Formaldehyde	1.15	5.02	5.02	
					Methane	17.56	76.93	76.93	
					Naphthalene	0.0021	0.0092	0.0092	
					Nitrogen Oxides	73.51	330.1	330.1	
					Nitrous Oxide	0.45	1.97	1.97	
					Particulate Matter	13.48	59.04	59.04	
					PM < 2.5 micron	13.48	59.04	59.04	
					PM < 10 micron	13.48	59.04	59.04	
					Propylene oxide	0.0469	0.205	0.205	
					Sulfur Dioxide	1.17	5.11	5.11	
					Toluene	0.21	0.92	0.92	
					Total Polycyclic aromatic hydrocarbons	0.00355	0.0156	0.0156	
					Volatile Organic Compounds	10.03	76.73	76.73	
					Xylenes, Total	0.103	0.453	0.453	
		EQUI 8	EU008	GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	1,3-Butadiene	0.000695	0.00304	0.00304	
					Acetaldehyde	0.0646	0.283	0.283	
					Acrolein	0.0103	0.0453	0.0453	
					Benzene	0.0194	0.0849	0.0849	
					Carbon Dioxide	224,664	984,028	984,028	
					Carbon Dioxide Equivalent	225,237	986,539	986,539	
					Carbon Monoxide	38.8	196.28	0	
					Ethylbenzene	0.0517	0.226	0.226	
					Formaldehyde	1.15	5.02	5.02	
					Methane	17.56	76.93	76.93	
					Naphthalene	0.0021	0.0092	0.0092	
					Nitrogen Oxides	73.51	330.1	330.1	
					Nitrous Oxide	0.45	1.97	1.97	
					Particulate Matter	13.48	59.04	59.04	
					PM < 2.5 micron	13.48	59.04	59.04	
					PM < 10 micron	13.48	59.04	59.04	
					Propylene oxide	0.0469	0.205	0.205	
					Sulfur Dioxide	1.17	5.11	5.11	
					Toluene	0.21	0.92	0.92	
					Total Polycyclic aromatic hydrocarbons	0.00355	0.0156	0.0156	
					Volatile Organic Compounds	10.03	76.73	76.73	
					Xylenes, Total	0.103	0.453	0.453	

Relationships

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Relationship	Related SI ID	% Flow	Related SI Type	Related Delta Designation	Relationship Start Date	Relationship End Date	
Equipment	Data Acquisition System	EQUI 16	Null	Stackvision Data Acquisition System	receives from	EQUI 9	Null	Continuous Emission Monitor	MR001	11/2/2022	Null	
						EQUI 10	Null	Continuous Emission Monitor	MR002	11/2/2022	Null	
						EQUI 11	Null	Continuous Emission Monitor	MR003	11/2/2022	Null	
						EQUI 12	Null	Continuous Emission Monitor	MR004	11/2/2022	Null	
						EQUI 21	Null	Parametric Monitor	Null	9/3/2019	Null	
						EQUI 22	Null	Parametric Monitor	Null	9/3/2019	Null	
						EQUI 30	Null	Continuous Emission Monitor	Null	11/2/2022	Null	
						EQUI 31	Null	Continuous Emission Monitor	Null	11/2/2022	Null	
						EQUI 34	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 35	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 36	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 37	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 38	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 39	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 40	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 41	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 42	Null	Parametric Monitor	Null	5/17/2024	Null	
	Reciprocating IC Engine	EQUI 5	EU005	Emergency Engine/Generator	sends to	STRU 14	Null	Stack/Vent	SV005	9/12/2019	Null	
		EQUI 23	Null	Engine Generator 1	is controlled by	TREA 1	100	312-Oxidation Catalyst	Null	4/1/2024	Null	
						TREA 2	100	139-SCR (Selective Catalytic Reduction)	Null	4/1/2024	Null	
					sends to	STRU 24	100	Stack/Vent	Null	4/1/2024	Null	
		EQUI 24	Null	Engine Generator 2	is controlled by	TREA 3	100	312-Oxidation Catalyst	Null	4/1/2024	Null	
						TREA 4	100	139-SCR (Selective Catalytic Reduction)	Null	4/1/2024	Null	
					sends to	STRU 25	100	Stack/Vent	Null	4/1/2024	Null	
		EQUI 25	Null	Engine Generator 3	is controlled by	TREA 5	100	312-Oxidation Catalyst	Null	4/1/2024	Null	
						TREA 6	100	139-SCR (Selective Catalytic Reduction)	Null	4/1/2024	Null	
					sends to	STRU 26	100	Stack/Vent	Null	4/1/2024	Null	
		EQUI 26	Null	Emergency Generator 2	sends to	STRU 27	100	Stack/Vent	Null	4/1/2024	Null	
		EQUI 27	Null	Emergency Generator 3	sends to	STRU 28	100	Stack/Vent	Null	4/1/2024	Null	
		EQUI 28	Null	Emergency Generator 4	sends to	STRU 29	100	Stack/Vent	Null	4/1/2024	Null	
		EQUI 29	Null	Emergency Generator 5	sends to	STRU 30	100	Stack/Vent	Null	4/1/2024	Null	
		EQUI 43	Null	Emergency Generator 6	sends to	STRU 38	100	Stack/Vent	Null	6/17/2024	Null	
	Turbine	EQUI 1	EU001	Combustion Turbine 1 (50 MW) - Turbine	sends to	STRU 16	100	Stack/Vent	SV001	3/16/2000	Null	
		EQUI 2	EU002	Combustion Turbine 2 (50 MW) - Turbine	sends to	STRU 17	100	Stack/Vent	SV002	3/16/2000	Null	
		EQUI 3	EU003	Combustion Turbine 3 (50 MW) - Turbine	sends to	STRU 18	100	Stack/Vent	SV003	3/16/2000	Null	
		EQUI 4	EU004	Combustion Turbine 4 (55 MW) - Turbine	sends to	STRU 19	100	Stack/Vent	SV004	3/16/2000	Null	
		EQUI 7	EU007	GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	is monitored by	EQUI 9	Null	Continuous Emission Monitor	MR001	11/2/2022	Null	
						EQUI 10	Null	Continuous Emission Monitor	MR002	11/2/2022	Null	
						EQUI 21	Null	Parametric Monitor	Null	9/3/2019	Null	

Relationships

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

SI Category	SI Type	Subject Item ID	Delta Designation	Description	Relationship	Related SI ID	% Flow	Related SI Type	Related Delta Designation	Relationship Start Date	Relationship End Date	
Equipment	Turbine	EQUI 7	EU007	GE Dry Low NOx Burner Combustion Turbine 7 (174 MW)	is monitored by	EQUI 30	Null	Continuous Emission Monitor	Null	11/2/2022	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	9/11/2019	Null	
						STRU 12	100	Stack/Vent	SV007	8/9/2004	Null	
		EQUI 8	EU008	GE Dry Low NOx Burner Combustion Turbine 8 (174 MW)	is monitored by	EQUI 11	Null	Continuous Emission Monitor	MR003	11/2/2022	Null	
						EQUI 12	Null	Continuous Emission Monitor	MR004	11/2/2022	Null	
						EQUI 22	Null	Parametric Monitor	Null	9/3/2019	Null	
						EQUI 31	Null	Continuous Emission Monitor	Null	11/2/2022	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	9/11/2019	Null	
						STRU 13	100	Stack/Vent	SV008	8/9/2004	Null	
Treatment	139-SCR (Selective Catalytic Reduction)	TREA 2	Null	Selective Catalytic Reduction	is controlled in series by	TREA 1	100	312-Oxidation Catalyst	Null	4/1/2024	Null	
					is monitored by	EQUI 34	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 35	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 36	Null	Parametric Monitor	Null	5/17/2024	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	5/17/2024	Null	
		TREA 4	Null	Selective Catalytic Reduction	is controlled in series by	TREA 3	100	312-Oxidation Catalyst	Null	4/1/2024	Null	
					is monitored by	EQUI 37	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 38	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 39	Null	Parametric Monitor	Null	5/17/2024	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	5/17/2024	Null	
		TREA 6	Null	Selective Catalytic Reduction	is controlled in series by	TREA 5	100	312-Oxidation Catalyst	Null	4/1/2024	Null	
					is monitored by	EQUI 40	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 41	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 42	Null	Parametric Monitor	Null	5/17/2024	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	5/17/2024	Null	
	312-Oxidation Catalyst	TREA 1	Null	Oxidation Catalyst	is monitored by	EQUI 34	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 35	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 36	Null	Parametric Monitor	Null	5/17/2024	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	5/17/2024	Null	
		TREA 3	Null	Oxidation Catalyst	is monitored by	EQUI 37	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 38	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 39	Null	Parametric Monitor	Null	5/17/2024	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	5/17/2024	Null	
		TREA 5	Null	Oxidation Catalyst	is monitored by	EQUI 40	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 41	Null	Parametric Monitor	Null	5/17/2024	Null	
						EQUI 42	Null	Parametric Monitor	Null	5/17/2024	Null	
					sends to	EQUI 16	Null	Data Acquisition System	Null	5/17/2024	Null	

Aboveground Storage Tanks

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item ID	Delta Designation	Description	Capacity (gal)	Construction Type	Column Diameter (ft)	Number of Columns	Deck Type	Interior Diameter (ft)	Interior Height (ft)	Max True Vapor Pressure (psia)	Construction Type	Seal Type	Support Type	Construction or Installation Start Date	
EQUI 32	Null	Diesel Tank #1	100000	Fixed Roof	Null	Null	Null	21	40	0.01	Fixed Roof	Null	Null	TBD	
EQUI 33	Null	Diesel Tank #2	100000	Fixed Roof	Null	Null	Null	21	40	0.01	Fixed Roof	Null	Null	TBD	

CEMs

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item ID	Delta Designation	Description	Manufacturer	Model	Serial Number	Parameter	Primary or Backup?	Bypass Capability?	Install Date (CEMs/COMs)	Certification Date	Certification Basis	Span (ppm)	System Full Scale Value (ppm)	
EQUI 9	MR001	NOx CEMS for EQUI 7	TBD	TBD	TBD	Nitrogen Oxides	B	No	Null	Null	Null	Null	Null	
EQUI 10	MR002	CO CEMS for EQUI 7	TBD	TBD	TBD	Carbon Monoxide	B	No	Null	Null	Null	Null	Null	
EQUI 11	MR003	NOx CEMS for EQUI 8	TBD	TBD	TBD	Nitrogen Oxides	B	No	Null	Null	Null	Null	Null	
EQUI 12	MR004	CO CEMS for EQUI 8	TBD	TBD	TBD	Carbon Monoxide	B	No	Null	Null	Null	Null	Null	
EQUI 30	Null	EQUI 7 O2 CEMS (diluent)	Servomex	4900	200112	Oxygen	Primary	No	11/2/2022	Null	40 CFR Pt 75	0	25	
EQUI 31	Null	EQUI 8 O2 CEMS (diluent)	Servomex	4900	200112	Oxygen	Primary	No	11/2/2022	Null	40 CFR Pt 75	0	25	

PMs

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item ID	Delta Designation	Description	Manufacturer	Model	Serial Number	Parameter Monitored	Bypass Capability? (parametric)	Install Date (parametric)	
EQUI 21	Null	Fuel usage parametric monitor for EQUI 7	Rosemount	3095MA2CA0013AA	3051SMV	Fuel Usage	No	4/1/2014	
EQUI 22	Null	Fuel usage parametric monitor for EQUI 8	Rosemount	0060496	0408479	Fuel Usage	No	6/10/2014	
EQUI 34	Null	EQUI 23 SCR and Oxidation Catalyst Inlet Temperature	Null	Null	Null	Temperature	Null	5/17/2024	
EQUI 35	Null	EQUI 23 SCR and Oxidation Catalyst Inlet Pressure	Null	Null	Null	Pressure Drop	Null	5/17/2024	
EQUI 36	Null	EQUI 23 SCR and Oxidation Catalyst Outlet Pressure	Null	Null	Null	Pressure Drop	Null	5/17/2024	
EQUI 37	Null	EQUI 24 SCR and Oxidation Catalyst Inlet Temperature	Null	Null	Null	Temperature	Null	5/17/2024	
EQUI 38	Null	EQUI 24 SCR and Oxidation Catalyst Inlet Pressure	Null	Null	Null	Pressure Drop	Null	5/17/2024	
EQUI 39	Null	EQUI 24 SCR and Oxidation Catalyst Outlet Pressure	Null	Null	Null	Pressure Drop	Null	5/17/2024	
EQUI 40	Null	EQUI 25 SCR and Oxidation Catalyst Inlet Temperature	Null	Null	Null	Temperature	Null	5/17/2024	
EQUI 41	Null	EQUI 25 SCR and Oxidation Catalyst Inlet Pressure	Null	Null	Null	Pressure Drop	Null	5/17/2024	
EQUI 42	Null	EQUI 25 SCR and Oxidation Catalyst Outlet Pressure	Null	Null	Null	Pressure Drop	Null	5/17/2024	

DAS

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item ID	Delta Designation	Description	Manufacturer	Model	Serial Number	Primary or Backup? (DASs)	Install Date (DASs)	
EQUI 16	Null	Stackvision Data Acquisition System	Environmenal Systems Corp	StackVision	M79404	Primary	6/25/2007	

FUGI

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item Type	Subject Item ID	Delta Designation	Description	Install Year	Pollutants Emitted	
Paved Road	FUGI 1	Null	Engine generator fuel deliveries on paved road	2024	Particulate Matter	
					PM < 2.5 micron	
					PM < 10 micron	

Building

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item ID	Delta Designation	Description	Height	Units (height)	Length	Units (length)	Width	Units (width)	
STRU 1	BG002	Substation Generator Building	10	feet	15	feet	8	feet	
STRU 2	BG003	Foam House	10	feet	27	feet	27	feet	
STRU 3	BG004	Gas Turbine Building	14	feet	225	feet	85	feet	
STRU 4	BG005	Operations Building	16	feet	90	feet	40	feet	
STRU 5	BG006	Fuel Forwarding Building	10	feet	10	feet	8	feet	
STRU 6	BG007	Fire Foam Equipment Building	10	feet	10	feet	8	feet	
STRU 7	BG008	Fuel Oil Tank	40	feet	100	feet	Null	Null	
STRU 8	BG009	Fuel Oil Tank	40	feet	100	feet	Null	Null	
STRU 9	BG010	Warehouse	14	feet	53	feet	42	feet	
STRU 10	BG011	Gas Turbine 7 Structure	38.33	feet	92	feet	85	feet	
STRU 11	BG012	Gas Turbine 8 Structure	38.33	feet	92	feet	85	feet	
STRU 20	BG001	Substation controls building	16	feet	54	feet	18	feet	
STRU 31	Null	Rice #1 Equipment	28	feet	26	feet	10	feet	
STRU 32	Null	Rice #2 Equipment	28	feet	26	feet	10	feet	
STRU 33	Null	Rice #3 Equipment	28	feet	26	feet	10	feet	
STRU 34	Null	Rice Building Tier 1	20	feet	241	feet	72	feet	
STRU 35	Null	Rice Building Tier 2	40	feet	92	feet	72	feet	
STRU 36	Null	West Fuel Oil Tank #1	40	feet	27	feet	27	feet	
STRU 37	Null	West Fuel Oil Tank #2	40	feet	27	feet	27	feet	

Stack/Vents

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item ID	Delta Designation	Description	Stack Height (feet)	Stack Diameter (feet)	Stack Length (feet)	Stack Width (feet)	Stack Flow Rate (cubic ft/min)	Discharge Temperature (°F)	Flow Rate/Temp Information Source	Discharge Direction	
STRU 12	SV007	Combustion Turbine 7 (EQUI 7)	50	17.7	Null	Null	2,388,000	1,105	Manufacturer	Upwards with no cap on stack/vent	
STRU 13	SV008	Combustion Turbine 8 (EQUI 8)	50	17.7	Null	Null	2,388,000	1,105	Manufacturer	Upwards with no cap on stack/vent	
STRU 14	SV005	Substation engine/generator stack	11	0.3	Null	Null	874	952	Manufacturer	Upwards with no cap on stack/vent	
STRU 16	SV001	Combustion Turbine 1	52	Null	15.3	15.3	1,360,000	852	Manufacturer	Upwards with no cap on stack/vent	
STRU 17	SV002	Combustion Turbine 2	52	Null	15.3	15.3	1,360,000	852	Manufacturer	Upwards with no cap on stack/vent	
STRU 18	SV003	Combustion Turbine 3	52	Null	15.3	15.3	1,360,000	852	Manufacturer	Upwards with no cap on stack/vent	
STRU 19	SV004	Combustion Turbine 4	52	Null	15.3	15.3	1,360,000	950	Manufacturer	Upwards with no cap on stack/vent	
STRU 24	Null	EQUI 23 Stack	95	4	Null	Null	58,703	708.4	Manufacturer	Upwards with no cap on stack/vent	
STRU 25	Null	EQUI 24 Stack	95	4	Null	Null	58,703	708.4	Manufacturer	Upwards with no cap on stack/vent	
STRU 26	Null	EQUI 25 Stack	95	4	Null	Null	58,703	708.4	Manufacturer	Upwards with no cap on stack/vent	
STRU 27	Null	EQUI 26 Stack	8.75	1.05	Null	Null	6,028	847.2	Manufacturer	Upwards with no cap on stack/vent	
STRU 28	Null	EQUI 27 Stack	8.75	1.05	Null	Null	6,028	847.2	Manufacturer	Upwards with no cap on stack/vent	
STRU 29	Null	EQUI 28 Stack	8.75	1.05	Null	Null	6,028	847.2	Manufacturer	Upwards with no cap on stack/vent	
STRU 30	Null	EQUI 29 Stack	9.4	1.03	Null	Null	4,551.5	969.1	Manufacturer	Upwards with no cap on stack/vent	
STRU 38	Null	EQUI 43 Stack	9.4	1.03	Null	Null	4,551.5	969.1	Manufacturer	Upwards with no cap on stack/vent	

Other Controls

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item Type	Subject Item ID	Delta Designation	Description	Manufacturer (Model #)	Installation Start Date	Pollutants Controlled	Capture Efficiency (%)	Destruction/ Collect Efficiency (%)	Subject to CAM?	Large or Other PSEU?	Efficiency Basis	Other Basis Explanation	Other operating parameters?	Other operating parameters description
139-SCR (Selective Catalytic Reduction)	TREA 2	Null	Selective Catalytic Reduction	Custom (Custom)	4/1/2024	Nitrogen Oxides	100	90	Yes	Other	Mfr/ Vendor data	Null	Yes	annual stack testing, operate per manufacturer's specifications. SCR operating parameters controlled by engine computer.
	TREA 4	Null	Selective Catalytic Reduction	Custom (Custom)	4/1/2024	Nitrogen Oxides	100	90	Yes	Other	Mfr/ Vendor data	Null	Yes	annual stack testing, operate per manufacturer's specifications. SCR operating parameters controlled by engine computer.
	TREA 6	Null	Selective Catalytic Reduction	Custom (Custom)	4/1/2024	Nitrogen Oxides	100	90	Yes	Other	Mfr/ Vendor data	Null	Yes	annual stack testing, operate per manufacturer's specifications. SCR operating parameters controlled by engine computer.

Catalysts

AI ID (Name): 1860 (Xcel Energy - Blue Lake)
Activity: IND20220001

Subject Item Type	Subject Item ID	Delta Designation	Description	Manufacturer (Model #)	Installation Start Date	Pollutants Controlled	Capture Efficiency (%)	Destruction/ Collect Efficiency (%)	Subject to CAM?	Large or Other PSEU?	Efficiency Basis	Other Basis Explanation	Catalyst Inlet Temp (°F)	Catalyst Outlet Temp (°F)	
312-Oxidation Catalyst	TREA 1	Null	Oxidation Catalyst	Custom (Custom)	4/1/2024	Carbon Monoxide	100	90	Yes	Other	Mfr/ Vendor data	Null	484	1,350	
						Volatile Organic Compounds	100	90	Yes	Other	Mfr/ Vendor data	Null	484	1,350	
	TREA 3	Null	Oxidation Catalyst	Custom (Custom)	4/1/2024	Carbon Monoxide	100	90	Yes	Other	Mfr/ Vendor data	Null	484	1,350	
						Volatile Organic Compounds	100	90	Yes	Other	Mfr/ Vendor data	Null	484	1,350	
	TREA 5	Null	Oxidation Catalyst	Custom (Custom)	4/1/2024	Carbon Monoxide	100	90	Yes	Other	Mfr/ Vendor data	Null	484	1,350	
						Volatile Organic Compounds	100	90	Yes	Other	Mfr/ Vendor data	Null	484	1,350	

SI Id	Sequence	ID	Requirement
TFAC 1	1	1330929	Comply with all acid rain requirements. These are included in Section 5 of the permit and also in the acid rain permit application attached as Appendix B. [40 CFR pt. 72, 40 CFR pt. 73, 40 CFR pt. 75, 40 CFR pt. 76, Minn. R. 7007.1075]
TFAC 1	2	1327462	Emissions from the stationary source cannot exceed any allowances that the source lawfully holds under federal acid rain regulations, except as allowed by Minn. R. 7007.0800, subp. 7. [Minn. R. 7007.0800, subp. 7]
TFAC 1	3	1524618	Keep the certificate of representation, all emissions monitoring information, copies of all reports, compliance certifications and related submissions and all records made or required under the Acid Rain Program on site for a period of 5 years from the date the document was created. [40 CFR 72.9(f), Minn. R. 7007.1075]
TFAC 1	4	1524619	Hold allowances after January 1, 2001, as of the allowance transfer deadline, in the affected unit's compliance subaccount. Allowances may not be less than the total annual emissions of sulfur dioxide from the previous calendar year from the unit. [40 CFR 72.9(c), Minn. R. 7007.1075]
TFAC 1	1240	1524625	Permit Appendices: This permit contains appendices as listed in the permit Table of Contents. The Permittee shall comply with all requirements contained in Appendix A - Insignificant Activities and General Applicable Requirements; Appendix B - Acid Rain Permit Renewal Application; Appendix C - 40 CFR Part 60 Subpart A, General Provisions; Appendix D - 40 CFR Part 63, subp. A, General Provisions; Appendix E - 40 CFR Part 63 Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines; Appendix F - Transport Rule (TR) Trading Program Title V Requirements; Appendix G - 40 CFR Part 60 Subpart IIII Standards of Performance for Stationary Compression Ignition Internal Combustion Engines; Appendix H - Fugitive Dust Control Plan; Appendix I - General Public Preclusion Plan; Appendix K - 40 CFR Part 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. Modeling parameters in Appendix J - Modeling Parameters are included for reference only as described elsewhere in this permit. [Minn. R. 7007.0800, subp. 2(A) & (B)]
TFAC 1	1245	1444571	The Permittee must comply with Minn. Stat. 116.385. The Permittee may not use trichloroethylene at its permitted facility including in any manufacturing, processing, or cleaning processes, except as described in Minn. Stat. 116.385, subd. 2(b) and 4. This is a state-only requirement and is not enforceable by the U.S. Environmental Protection Agency (EPA) Administrator and citizens under the Clean Air Act. [Minn. R. 7007.0100, subp. 7(X), Minn. Stat. 116.385]
TFAC 1	1260	1262799	PERMIT SHIELD: Subject to the limitations in Minn. R. 7007.1800, compliance with the conditions of this permit shall be deemed compliance with the specific provision of the applicable requirement identified in the permit as the basis of each condition. Subject to the limitations of Minn. R. 7007.1800 and 7017.0100, subp. 2, notwithstanding the conditions of this permit specifying compliance practices for applicable requirements, any person (including the Permittee) may also use other credible evidence to establish compliance or noncompliance with applicable requirements. This permit shall not alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of permit issuance. [Minn. R. 7007.1800(A)(2)]
TFAC 1	1280	1526153	Comply with Fugitive Emission Control Plan: The Permittee shall follow the actions and recordkeeping specified in the fugitive dust control plan in Appendix H of this permit. If the Commissioner determines the Permittee is out of compliance with Minn. R. 7011.0150 or the fugitive control plan, then the Permittee may be required to amend the control plan and/or to install and operate particulate matter ambient monitors as requested by the Commissioner. [Minn. R. 7007.0800, subp. 2(A), Minn. R. 7009.0020, Minn. R. 7011.0150, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	1290	1346407	The Permittee shall comply with National Primary and Secondary Ambient Air Quality Standards, 40 CFR pt. 50, and the Minnesota Ambient Air Quality Standards, Minn. R. 7009.0010 to 7009.0090. Compliance shall be demonstrated upon written request by the MPCA. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	1380	1030618	Circumvention: Do not install or use a device or means that conceals or dilutes emissions, which would otherwise violate a federal or state air pollution control rule, without reducing the total amount of pollutant emitted. [Minn. R. 7011.0020]
TFAC 1	1390	1479361	The Permittee must at all times properly operate and maintain the facilities and systems of treatment and control and the appurtenances related to them that are installed or used by the Permittee to achieve compliance with the conditions of the permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. [Minn. R. 7007.0800, subp. 16(J)]

SI Id	Sequence	ID	Requirement
TFAC 1	1400	1059092	Operation and Maintenance Plan: Retain at the stationary source an operation and maintenance plan for all air pollution control equipment. At a minimum, the O & M plan shall identify all air pollution control equipment and control practices and shall include a preventative maintenance program for the equipment and practices, a description of (the minimum but not necessarily the only) corrective actions to be taken to restore the equipment and practices to proper operation to meet applicable permit conditions, a description of the employee training program for proper operation and maintenance of the control equipment and practices, and the records kept to demonstrate plan implementation. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subp. 16(J)]
TFAC 1	1410	1440483	Operation Changes: In any shutdown, breakdown, or deviation the Permittee must immediately or as soon as possible considering plant and personnel safety take all practical steps to modify operations to reduce the emission of any regulated air pollutant. No emissions units that have an unreasonable shutdown or breakdown frequency of process or control equipment are permitted to operate. [Minn. R. 7019.1000, subp. 4]
TFAC 1	1420	1030622	Fugitive Emissions: Do not cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne. Comply with all other requirements listed in Minn. R. 7011.0150. [Minn. R. 7011.0150]
TFAC 1	1430	1030623	Noise: The Permittee shall comply with the noise standards set forth in Minn. R. 7030.0010 to 7030.0080 at all times during the operation of any emission units. This is a state only requirement and is not enforceable by the EPA Administrator or citizens under the Clean Air Act. [Minn. R. 7030.0010-7030.0080]
TFAC 1	1440	1030624	Inspections: The Permittee shall comply with the inspection procedures and requirements as found in Minn. R. 7007.0800, subp. 9(A). [Minn. R. 7007.0800, subp. 9(A)]
TFAC 1	1450	1030625	The Permittee shall comply with the General Conditions listed in Minn. R. 7007.0800, subp. 16. [Minn. R. 7007.0800, subp. 16]
TFAC 1	1460	1091249	Performance Testing: Conduct all performance tests in accordance with Minn. R. ch. 7017 unless otherwise noted in this permit. [Minn. R. ch. 7017]
TFAC 1	1470	1517542	Performance Test Notifications and Submittals: Performance Test Notification and Plan: due 30 days before each Performance Test Performance Test Pre-test Meeting: due seven days before each Performance Test Performance Test Report: due 45 days after each Performance Test The Notification, Test Plan, and Test Report must be submitted in a format specified by the commissioner. [Minn. R. 7017.2017, Minn. R. 7017.2030, subps. 1-4, Minn. R. 7017.2035, subps. 1-2]
TFAC 1	1480	1030628	Limits set as a result of a performance test (conducted before or after permit issuance) apply until superseded as stated in the MPCA's Notice of Compliance letter granting preliminary approval. Preliminary approval is based on formal review of a subsequent performance test on the same unit as specified by Minn. R. 7017.2025, subp. 3. The limit is final upon issuance of a permit amendment incorporating the change. [Minn. R. 7017.2025, subp. 3]
TFAC 1	1490	1124511	Monitoring Equipment Calibration - The Permittee shall either: 1. Calibrate or replace required monitoring equipment every 12 months; or 2. Calibrate at the frequency stated in the manufacturer's specifications. For each monitor, the Permittee shall maintain a record of all calibrations, including the date conducted, and any corrective action that resulted. The Permittee shall include the calibration frequencies, procedures, and manufacturer's specifications (if applicable) in the Operations and Maintenance Plan. Any requirements applying to continuous emission monitors are listed separately in this permit. [Minn. R. 7007.0800, subp. 4(D)]
TFAC 1	1500	1030630	Operation of Monitoring Equipment: Unless noted elsewhere in this permit, monitoring a process or control equipment connected to that process is not necessary during periods when the process is shutdown, or during checks of the monitoring systems, such as calibration checks and zero and span adjustments. If monitoring records are required, they should reflect any such periods of process shutdown or checks of the monitoring system. [Minn. R. 7007.0800, subp. 4(D)]
TFAC 1	1510	1370544	Recordkeeping: Retain all records at the stationary source, unless otherwise specified within this permit, for five (5) years from the date of monitoring, sample, measurement, or report. Records which must be retained at this location include all calibration and maintenance records, all original recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. Records must conform to the requirements listed in Minn. R. 7007.0800, subp. 5(A). [Minn. R. 7007.0800, subp. 5(C)]

SI Id	Sequence	ID	Requirement
TFAC 1	1520	1030642	Recordkeeping: Maintain records describing any insignificant modifications (as required by Minn. R. 7007.1250, subp. 3) or changes contravening permit terms (as required by Minn. R. 7007.1350, subp. 2), including records of the emissions resulting from those changes. [Minn. R. 7007.0800, subp. 5(B)]
TFAC 1	1530	1524626	If the Permittee determines that no permit amendment or notification is required prior to making a change, the Permittee must retain records of all calculations required under Minn. R. 7007.1200. For expiring permits, these records shall be kept for a period of five years from the date the change was made or until permit reissuance, whichever is longer. The records shall be kept at the stationary source for the current calendar year of operation and may be kept at the stationary source or office of the stationary source for all other years. The records may be maintained in either electronic or paper format. [Minn. R. 7007.1200, subp. 4]
TFAC 1	1540	1487345	These following 40 CFR 52.21(r)(6) requirements apply if a reasonable possibility (RP) as defined in 40 CFR 52.21(r)(6)(vi) exists that a proposed project, analyzed using the actual-to-projected-actual (ATPA) test (either by itself or as part of the hybrid test at 40 CFR 52.21(a)(2)(iv)(f)) and found to not be part of a major modification, may result in a significant emissions increase (SEI). If the ATPA test is not used for the project, or if there is no RP that the proposed project could result in a SEI, these requirements do not apply to that project. The Permittee is only subject to the Preconstruction Documentation requirement for a project where a RP occurs only within the meaning of 40 CFR 52.21(r)(6)(vi)(b). Even though a particular modification is not subject to New Source Review (NSR), or where there isn't a RP that a proposed project could result in a SEI, a permit amendment, recordkeeping, or notification may still be required by Minn. R. 7007.1150 - 7007.1500. [Minn. R. 7007.0800, subp. 2(A), Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]
TFAC 1	1550	1487346	Preconstruction Documentation -- Before beginning actual construction on a project, the Permittee shall document the following: 1. Project description 2. Identification of any emission unit whose emissions of an NSR pollutant could be affected 3. Pre-change potential emissions of any affected existing emission unit, and the projected post-change potential emissions of any affected existing or new emission unit. 4. A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded due to increases not associated with the modification and that the emission unit could have accommodated during the baseline period, an explanation of why the amounts were excluded, and any creditable contemporaneous increases and decreases that were considered in the determination. The Permittee shall maintain records of this documentation. [Minn. R. 7007.0800, subps. 4-5, Minn. R. 7007.1200, subp. 4, Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]
TFAC 1	1560	1487347	The Permittee shall monitor the actual emissions of any regulated NSR pollutant that could increase as a result of the project and that were analyzed using the ATPA test, and the potential emissions of any regulated NSR pollutant that could increase as a result of the project and that were analyzed using potential emissions in the hybrid test. The Permittee shall calculate and maintain a record of the sum of the actual and potential (if the hybrid test was used in the analysis) emissions of the regulated pollutant, in tons per year on a calendar year basis, for a period of five years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit of any unit associated with the project. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]
TFAC 1	1570	1487348	The Permittee must submit a report to the Agency if the annual summed (actual, plus potential if used in hybrid test) emissions differ from the preconstruction projection and exceed the baseline actual emissions by a significant amount as listed at 40 CFR 52.21(b)(23). Such report shall be submitted to the Agency within 60 days after the end of the year in which the exceedances occur. The report shall contain: a. The name and ID number of the Facility, and the name and telephone number of the Facility contact person. b. The annual emissions (actual, plus potential if any part of the project was analyzed using the hybrid test) for each pollutant for which the preconstruction projection and significant emissions increase are exceeded. c. Any other information, such as an explanation as to why the summed emissions differ from the preconstruction projection. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(r)(6) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
TFAC 1	1610	1440484	Shutdown Notifications: Notify the commissioner at least 24 hours in advance of a planned shutdown of any control equipment or process equipment if the shutdown would cause any increase in the emissions of any regulated air pollutant. If the Permittee does not have advance knowledge of the shutdown, the Permittee must notify the commissioner as soon as possible after the shutdown. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 3. At the time of notification, the owner or operator must inform the commissioner of the cause of the shutdown and the estimated duration. The owner or operator must notify the commissioner when the shutdown is over. [Minn. R. 7019.1000, subp. 3]
TFAC 1	1620	1440485	Breakdown Notifications: Notify the commissioner within 24 hours of a breakdown of more than one hour of any control equipment or process equipment if the breakdown causes any increase in the emissions of any regulated air pollutant. The 24-hour time period starts when the breakdown was discovered or reasonably should have been discovered by the owner or operator. However, notification is not required in the circumstances outlined in items A, B, and C of Minn. R. 7019.1000, subp. 2. At the time of notification or as soon as possible thereafter, the Permittee must inform the commissioner of the cause of the breakdown and the estimated duration. The Permittee must notify the commissioner when the breakdown is over. [Minn. R. 7019.1000, subp. 2]
TFAC 1	1630	1440486	Notification of Deviations Endangering Human Health or the Environment: Immediately after discovery of the deviation or immediately after when the deviation reasonably should have been discovered, notify the commissioner either orally or by e-mail, or telephone the state duty officer at 800-422-0798 or 651-649-5451, of any deviation from permit conditions that could endanger human health or the environment. [Minn. R. 7019.1000, subp. 1]
TFAC 1	1640	1440487	Notification of Deviations Endangering Human Health or the Environment Report: Within two working days of discovery, notify the commissioner in writing of any deviation from permit conditions that could endanger human health or the environment. Include the following information in this written description: 1. the cause of the deviation; 2. the exact dates of the period of the deviation, if the deviation has been corrected; 3. whether or not the deviation has been corrected; 4. the anticipated time by which the deviation is expected to be corrected, if not yet corrected; and 5. steps taken or planned to reduce, eliminate, and prevent reoccurrence of the deviation. [Minn. R. 7019.1000, subp. 1]
TFAC 1	1650	1370545	The Permittee must submit a semiannual deviations report : Due semiannually, by the 30th of January and July. The first semiannual report submitted by the Permittee must cover the calendar half-year in which the permit is issued. The first report of each calendar year covers January 1 - June 30. The second report of each calendar year covers July 1 - December 31. Submit this on form DRF-2 (Deviation Reporting Form). If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(B)(2)]
TFAC 1	1670	1376486	Application for Permit Amendment: If a permit amendment is needed, submit an application in accordance with the requirements of Minn. R. 7007.1150 through Minn. R. 7007.1500. Submittal dates vary, depending on the type of amendment needed. Upon adoption of a new or amended federal applicable requirement, and if there are three or more years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150 - 7007.1500]
TFAC 1	1680	1030651	Extension Requests: The Permittee may apply for an Administrative Amendment to extend a deadline in a permit by no more than 120 days, provided the proposed deadline extension meets the requirements of Minn. R. 7007.1400, subp. 1(H). Performance testing deadlines from the General Provisions of 40 CFR pt. 60 and pt. 63 are examples of deadlines for which the MPCA does not have authority to grant extensions and therefore do not meet the requirements of Minn. R. 7007.1400, subp. 1(H). [Minn. R. 7007.1400, subp. 1(H)]
TFAC 1	1700	1370547	The Permittee must submit a compliance certification : Due annually, by the 31st of January (for the previous calendar year). Submit this on form CR-04 (Annual Compliance Certification Report). This report covers all deviations experienced during the calendar year. If no deviations have occurred, submit the signed report certifying that there were no deviations. [Minn. R. 7007.0800, subp. 6(D)]
TFAC 1	1703	1370548	Within 15 days of a request from the Commissioner, the Permittee must provide a complete summary of all performance tests required at the facility including the subject item, pollutant, most recent test date (if applicable), and the date of the next test in an approved format. [Minn. R. 7007.0800, subp. 16(L)]

SI Id	Sequence	ID	Requirement
TFAC 1	1710	1030634	The Permittee shall submit an application for permit reissuance : Due 180 calendar days before Permit Expiration Date. [Minn. R. 7007.0400, subp. 2]
TFAC 1	1730	1180641	Emission Inventory Report: due on or before April 1 of each calendar year following permit issuance. Submit in a format specified by the Commissioner. [Minn. R. 7019.3000-7019.3100]
TFAC 1	1740	1330471	Emission Fees: due 30 days after receipt of an MPCA bill. [Minn. R. 7002.0005-7002.0085]
TFAC 1	1860	1525807	Modeled Parameters for NO2: The parameters used in NO2 modeling for permit number 13900010-105 are listed in Appendix J of this permit. The parameters describe the operation of the facility at maximum permitted capacity. The purpose of listing the parameters in the appendix is to provide a benchmark for future changes. [Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
TFAC 1	1870	1524643	Modeled Parameters for PM2.5: The parameters used in PM2.5 modeling for permit number 13900010-105 are listed in Appendix J of this permit. The parameters describe the operation of the facility at maximum permitted capacity. The purpose of listing the parameters in the appendix is to provide a benchmark for future changes. [Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
TFAC 1	1880	1524644	Changes to Modeled Parameters for PM2.5: Any permit amendment that affects any modeled parameter or emission rate for PM2.5 listed in Appendix J must be a major amendment. Any addition to the information documented in Appendix J requires a major amendment. Any change in the location of the ambient air boundary documented in Appendix I requires a major amendment unless the new boundary completely encompasses the original boundary documented in Appendix I. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	3120	1524828	The Permittee is authorized to construct the following equipment: EQUI 23 (Engine Generator 1), EQUI 24 (Engine Generator 2), EQUI 25 (Engine Generator 3), EQUI 26 (Emergency Generator 2), EQUI 27 (Emergency Generator 3), EQUI 28 (Emergency Generator 4), EQUI 29 (Emergency Generator 5), EQUI 43 (Emergency Generator 6), TREA 1 (Oxidation Catalyst), TREA 2 (Selective Catalytic Reduction), TREA 3 (Oxidation Catalyst), TREA 4 (Selective Catalytic Reduction), TREA 5 (Oxidation Catalyst), and TREA 6 (Selective Catalytic Reduction). The construction authorization expires if construction does not commence within 18 months after Issuance of Air Emissions Permit No. 13900010-105, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. [40 CFR 52.21(r)(2)]
TFAC 1	3340	1285002	The Permittee shall submit excess emission/downtime report : Due by 30 days after the end of each calendar quarter following permit issuance. Submit this on form DRF-1 (Excess Emissions Reporting) as amended. The EER shall indicate all periods of monitor bypass and exceedances of the limit including those allowed by an applicable standard, i.e. during startup, shutdown, and malfunctions, as well as a summary of audit results and frequencies. If no excess emissions, downtime or bypasses occurred during the quarter, submit a signed report supplying the necessary monitor data needed to verify this. [Minn. R. 7017.1110, subp. 1-2]
TFAC 1	3340	1347481	If the Permittee elects to use CEMS, they shall submit excess emission/downtime report : Due by 30 days after the end of each calendar quarter following permit issuance. Submit this on form DRF-1 (Excess Emissions Reporting) as amended. The EER shall indicate all periods of monitor bypass and exceedances of the limit including those allowed by an applicable standard, i.e. during startup, shutdown, and malfunctions, as well as a summary of audit results and frequencies. If no excess emissions, downtime or bypasses occurred during the quarter, submit a signed report supplying the necessary monitor data needed to verify this. [Minn. R. 7017.1110, subp. 1-2]
TFAC 1	18910	1524649	Equivalent or Better Dispersion (EBD) Modeling Triggers (Modeling Required) for PM2.5: Changes that affect any modeled parameter or emission rate listed in Appendix J, or an addition to the information documented in Appendix J, trigger the EBD Modeling Submittal requirement. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	18920	1524650	EBD Modeling Submittal for PM2.5: For changes meeting the criteria in the EBD Modeling Triggers (Modeling Required) requirement, the Permittee shall submit an EBD modeling submittal in accordance with the current version of the MPCA modeling practices manual and shall wait for written approval (in the form of an issued permit amendment) before making such changes. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	18930	1524652	EBD Modeling Submittal Content for PM2.5: The information submitted must include, for stack and vent sources, source emission rate, location, height, diameters, exit velocity, exit temperature, discharge direction, use of rain caps or rain hats, and, if applicable, locations and dimensions of nearby buildings. For non-stack/vent sources, this includes the source emission rate, location, size and shape, release height, and, if applicable, any emission rate scalars, and the initial lateral dimensions and initial vertical dimensions and adjacent building heights. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]

SI Id	Sequence	ID	Requirement
TFAC 1	18940	1524654	Outdated EBD Baseline Modeling for PM2.5: Prior to conducting the EBD analysis, the Permittee shall use the current version of the MPCA modeling practices manual to determine if the Baseline Modeling (the most recent refined modeling demonstration) is outdated. If the Baseline Modeling is outdated, the Permittee shall update the Baseline Modeling to be consistent with the current version of the MPCA modeling practices manual. The updated modeling will become the new Baseline Modeling. This requirement does not require the Permittee to complete a new refined modeling demonstration using the revisions made for the EBD demonstration. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	18950	1524659	EBD Modeling Results for PM2.5: The dispersion characteristics due to the revisions of the information in Appendix J must be equivalent to or better than the dispersion characteristics modeled October 27, 2023. The Permittee shall demonstrate this equivalency in the proposal. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	18960	1524661	Computer Dispersion Modeling Triggers for PM2.5: The Permittee shall conduct a refined remodeling analysis in accordance with the Computer Dispersion Modeling requirements of this permit and the current version of the MPCA modeling practices manual if: (1) the results of the EBD modeling analysis do not demonstrate equivalent or better dispersion characteristics; (2) a conclusion cannot readily be made about the dispersion; (3) the criteria in the EBD Modeling Triggers requirement are met and the Permittee has previously conducted three successive EBD analyses using the same Baseline Modeling; or (4) the location of the ambient air boundary is being modified, unless the new boundary completely encompasses the original boundary documented in Appendix I. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	18970	1524664	Computer Dispersion Modeling Protocol: due 180 days after receipt of written MPCA request for PM2.5 refined modeling. The Permittee shall submit a Computer Dispersion Modeling Protocol that is complete and approvable by MPCA by the deadline in this requirement. This protocol will describe the proposed modeling methodology and input data, in accordance with the current version of the MPCA modeling practices manual. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	18980	1524665	Computer Dispersion Modeling Protocol: due 60 days after receipt of written MPCA request for revisions to the submitted protocol for PM2.5 modeling. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	19390	1524666	Computer Dispersion Modeling Results: due 180 days after receipt of written MPCA approval of Computer Dispersion Modeling Protocol for PM2.5. The Permittee shall submit a final Computer Dispersion Modeling Report that is complete and approvable by MPCA by the deadline in this requirement. The submittal shall adhere to the current version of the MPCA modeling practices manual and the approved Computer Dispersion Modeling Protocol. [Minn. R. 7007.0800, subp. 2(A) & (B), Minn. R. 7009.0020-7009.0090, Minn. Stat. 116.07, subd. 4a(a)]
TFAC 1	21350	1526121	General Public Preclusion Plan The Permittee shall develop and comply with a General Public Preclusion Plan. The Permittee shall maintain a copy of the Plan at the facility. The Permittee shall review the General Public Preclusion Plan annually and update if needed to reflect changes associated with controlling the ambient air boundary. The plan as of Permit Issuance is included as Appendix I. This Plan shall, at a minimum, contain the following information: 1. A map of the facility that clearly displays the ambient air boundary. The map must indicate how access is precluded for each section of the boundary and must identify all access points (including roadways, power lines, rail spurs, etc.); 2. Locations where fencing will be implemented; 3. Locations where security patrols will be implemented and the security patrol frequency; 4. Restriction signage spacing (restriction signage may include notices such as "No Trespassing," "Private Property," "Do Not Enter," or "Restricted Area"); 5. Location of remote monitoring devices; 6. Operation and maintenance requirements of remote monitoring software and devices; 7. Contingency plans for downtime for remote monitoring software and devices; and 8. A response plan for when breaches occur. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
TFAC 1	21360	1532116	Recordkeeping for Breaches of the Ambient Air Boundary Within three calendar days of each observed breach, the Permittee shall document each instance that the ambient air boundary was breached by a member of the general public, including documenting the type, location, and duration of each breach. The Permittee shall identify and, within a reasonable amount of time but not to exceed 4 days, implement measures to prevent future breaches. A breach to the ambient boundary occurs when a member of the general public accesses property identified by the Permittee as non-ambient air. The observation of a breach may be direct or indirect. A direct observation includes witnessing a member of the general public on property identified as non-ambient air. Indirect observations rely on evidence of a breach, such as a cut fence, worn paths, motorized vehicle tracks, or other signs of disturbance by a member of the general public on property identified as non-ambient air. The Permittee shall report each breach, including all steps taken or changes made to the General Public Preclusion Plan to prevent additional breaches, in the semiannual Deviations Report required by this permit. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
TFAC 1	21370	1526118	General Public Preclusion Plan - Fencing: The Permittee shall install and maintain fencing along ambient air boundary as depicted in Appendix I. The Permittee shall inspect the fence line once per quarter. The Permittee shall maintain records of inspection and required maintenance of fence line. [Minn. R. 7007.0800, subp. 4(D), Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
TFAC 1	21380	1350536	General Public Preclusion Plan - Control of Access: The Permittee shall control access at any road, trail equal to or wider than 50 inches, and all abandoned railroad grades. The Permittee shall secure these access points with a locked and/or monitored gate or other physical barrier precluding access by the general public. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
TFAC 1	21390	1350537	General Public Preclusion Plan - Security Patrols: The Permittee shall develop, operate, and maintain a security patrol plan as part of the Plan. Patrol routes shall be followed as defined in the Plan. For portions of the effective fence line where patrols are identified, the Permittee shall patrol those portions at a minimum of once per operating day. The Permittee shall maintain records of patrol routes and frequency of patrols. [Minn. R. 7007.0800, subp. 4(D), Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
TFAC 1	21400	1526119	General Public Preclusion Plan - Remote Monitoring: The Permittee shall operate and maintain remote monitoring equipment to maintain the effective fence line as depicted in Appendix I. The Permittee shall monitor at a minimum of once per day. Remote monitoring devices include but are not limited to fixed cameras and drone mounted cameras. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
TFAC 1	21405	1526120	General Public Preclusion Plan – Boundary Map Within 30 days after Permit Issuance or prior to initial startup of EQUIs 23-29, whichever comes first, the Permittee shall use fencing, control access points, conduct security patrols, place restriction signage, and remote monitoring as specified in Appendix I to maintain control over the fence line. Appendix I to this permit is a map that depicts the boundary at which the access of the general public can be controlled and compliance with the National Ambient Air Quality Standards (NAAQS) can be demonstrated. Appendix I identifies the forms of control the Permittee will use to restrict access to the general public along portions of the fence line. The general public does not include employees or other categories of people who have been directly authorized by the property owner to enter or remain on the property for a limited period of time and for a specific purpose. [Minn. R. 7007.0800, subp. 4(D), Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
COMG 2	1	1524839	The Permittee shall limit emissions of Carbon Monoxide <= 310.8 tons per year 12-month rolling sum. This limit applies to the combined CO emissions of EQUI 7 and EQUI 8. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]

SI Id	Sequence	ID	Requirement
COMG 2	2	1532636	Monthly Recordkeeping. CO Emissions: By the 15th of the month, the Permittee shall calculate and record: 1) COMG 2 CO emissions for the previous calendar month by summing the CO emissions from EQUI 7 and EQUI 8 as determined according to requirements at EQUI 7 and EQUI 8; and, 2) Total COMG 2 CO emissions for the previous 12-month period by summing the monthly COMG 2 CO emissions data for the previous 12 months. Records shall include COMG 2 CO emissions for the previous calendar month and the previous 12-month period. [Minn. R. 7007.0800, subps. 4-5]
COMG 4	1	1524289	If the owner or operator has installed a NOx CEMS to meet the requirements of 40 CFR Part 75 of this chapter, and is continuing to meet the ongoing requirements of 40 CFR Part 75 of this chapter, the CEMS may be used to meet the requirements of 40 CFR 60.334, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR 60.7(c). [40 CFR 60.334(b)(3)(iii), Minn. R. 7011.2350]
COMG 4	2410	1440492	Additional monitoring requirements may apply. The Permittee is responsible for meeting all applicable requirements. [Minn. R. 7007.0800, subp. 4(A)]
COMG 4	2420	1544765	Emissions Monitoring: The owner or operator shall use a CEMS to measure emissions from EQUI 7 and EQUI 8. [40 CFR 75.10(a)]
COMG 4	2430	1531212	Certification Application: The Permittee shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The Permittee shall submit the certification application in accordance with 40 CFR 75.60 and each complete certification application shall include the information specified in 40 CFR 75.60 and 40 CFR 75.63. [40 CFR 75.20(a)(2), 40 CFR 75.60(b)(1), 40 CFR 75.63]
COMG 4	2440	1531213	Monitoring Data: Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data is unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to 40 CFR 75.21 and appendix B of 40 CFR pt. 75, or backups of data from the data acquisition and handling system, or recertification, pursuant to 40 CFR 75.20. The Permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. [40 CFR 75.10(d)(1)]
COMG 4	2450	1265233	CEMS QA/QC: The owner or operator of an affected facility shall operate, calibrate, and maintain each CEMS according to the QA/QC procedures in 40 CFR pt. 75, Appendix B as amended. [40 CFR 75.21(a)]
COMG 4	2490	1531214	Quarterly Reports: Electronically report the data and information in 40 CFR 75.64(a), (b), and (c) to the Administrator quarterly. [40 CFR 75.64]
COMG 4	2500	1531215	Recordkeeping: The Permittee shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. The file shall contain all information required by 40 CFR 75.57. [40 CFR 75.57]
COMG 4	2555	1326717	Daily Calibration error (CE) Test: conduct daily CE testing on all CEMS required by the Acid Rain Program, in accordance with 40 CFR pt. 75, appendix B. [40 CFR pt. 75, Appendix B(Sect 2.1)]
COMG 4	2650	1440498	Installation Notification: due 60 days before installing the continuous emissions monitoring system. The notification shall include plans and drawings of the system. [Minn. R. 7017.1040, subp. 1]
COMG 5	1	1327515	The Permittee shall limit emissions of HAPs - Total <= 22.5 tons per year 12-month rolling sum to be calculated by the 15th day of each month for the previous 12-month period. [Title I Condition: Avoid major source under 40 CFR 63.2]
COMG 5	2	1327516	The Permittee shall limit emissions of HAPs - Single <= 9.0 tons per year 12-month rolling sum to be calculated by the 15th day of each month for the previous 12-month period. [Title I Condition: Avoid major source under 40 CFR 63.2]
COMG 5	3	1524247	HAPs: Daily Recordkeeping. On each day of operation, the Permittee shall calculate and record the total fuel usage for each emission unit EQUI 1-EQUI 4, EQUI 23-EQUI 29 and EQUI 43. See EQUI 7 and EQUI 8 daily recordkeeping requirements for EQUI 7 and EQUI 8 fuel usage. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: Avoid major source under 40 CFR 63.2]

SI Id	Sequence	ID	Requirement
COMG 5	4	1524248	Monthly Recordkeeping - Fuel Usage: By the 15th day of each month, the Permittee shall calculate and record: 1. the total fuel usage of EQUI 1-EQUI 4, EQUI 23-EQUI 29 and EQUI 43 for the previous month, and 2. the total fuel usage of EQUI 7 and EQUI 8 for the previous month. [Minn. R. 7007.0800, subps. 4-5]
COMG 5	5	1327522	HAPs: Monthly Recordkeeping: By the 15th day of each month the Permittee shall calculate and record the following: 1. Individual and total HAP emissions for the previous calendar month based on monthly fuel usage records and emission factors, using formulas in this permit. 2. Individual and total HAP emissions for the previous 12-month period by summing the monthly emissions data for the previous 12 months. See below for emission factor information. [Minn. R. 7007.0800, subps. 4-5]
COMG 5	6	1524250	HAPs: Monthly Calculation: The Permittee shall calculate each individual HAP and total HAP emissions using the following equations: COMG 5 HAP Emissions (tons/month) = Distillate fuel oil units emissions (tons per month) + Dual fuel fired units (tons per month) + Natural gas units emissions (tons per month) Distillate fuel oil units emissions (tons per month) = (DF*EF*HHVD)/2000 DF = Distillate fuel usage (gal/month) EF = HAP-specific emission factor (lbs/MMBtu) 1.29E-03 lb/MMBtu total HAP, 2.80E-04 lb/MMBtu single HAP (EQUIs 1-4) 1.06E-03 lb/MMBtu total HAP, 7.89E-05 lb/MMBtu single HAP (EQUIs 26-29, 43) HHVD = High heating value for distillate fuel oil (MMBtu/gal) Dual fuel units emissions (tons per month) = (DuF*EF)/2000 DuF = Dual fuel heat input (total MMBtu/month: diesel + natural gas) EF = HAP-specific emission factor (lbs/MMBtu) 1.70E-03 lb/MMBtu total HAP, 7.89E-05 lb/MMBtu single HAP (diesel) (EQUIs 23-25) 2.28E-02 lb/MMBtu total HAP, 3.24E-03 lb/MMBtu single HAP (natural gas) (EQUIs 23-25)
			Natural gas units emissions (tons per month) = (NGF*EF*HHVNG)/2000 NGF = Natural gas fuel usage (dscf/month) EF = HAP-specific emission factor (lbs/MMBtu) 7.17E-04 lb/MMBtu total HAP, 4.00E-04 lb/MMBtu single HAP (EQUIs 7, 8) HHVNG = High heating value for natural gas (MMBtu/dscf) Total HAPS (tons per month) are determined by summing all individual (single) HAP (tons per month) emissions. [Minn. R. 7007.0800, subps. 4-5]
COMG 5	7	1524253	Emission Factors: Emissions of any HAP calculated with an emission factor on a lb/mmBtu basis shall be calculated by converting fuel usage volume to fuel heat input on a high heating value basis. Approved emission factors are, in order of preference: 1. The emission factor determined during the most recent stack test for this facility and verified by the MPCA in a Notice of Compliance or Notice of Verification, or, 2. The emission factors in EPA's AP-42 chapter 3.1. Any emission factor determination testing shall follow the performance testing requirements in the TFAC 1 subject item in this permit. [Minn. R. 7007.0800, subps. 4-5]
COMG 7	2230	1440488	Additional monitoring requirements may apply. The Permittee is responsible for meeting all applicable requirements. [Minn. R. 7007.0800, subp. 4(A)]

SI Id	Sequence	ID	Requirement
COMG 7	2240	1544770	Carbon Monoxide: Emissions Monitoring: The Permittee must use a CEMS to measure emissions from EQUI 7 and EQUI 8. [40 CFR pt. 60, subp. GG, Minn. R. 7011.2350, Minn. R. 7017.1010, subp 1]
COMG 7	2260	1440489	Certification Test Plan due 30 days before Certification Test. Certification Test Pretest Meeting due seven days before Certification Test. Certification Test Report due 45 days after Certification Test. Notify the commissioner prior to making any planned change or if unforeseen, within two working days, when a monitor must be recertified as outlined in Minn. R. 7017.1050, subp. 2. Test plans and reports must be submitted in a format specified by the commissioner. [40 CFR 60.7(a)(5), Minn. R. 7017.1060, subp. 1-3, Minn. R. 7017.1080]
COMG 7	2270	1363371	Continuous Operation: CEMS must be operated and data recorded during all periods of emission unit operation including periods of emission unit start-up, shutdown, or malfunction except for periods of acceptable monitor downtime. This requirement applies whether or not a numerical emission limit applies during these periods. A CEMS must not be bypassed except in emergencies where failure to bypass would endanger human health, safety, or plant equipment. [40 CFR 60.13(e), Minn. R. 7017.1010, subp. 1(A), Minn. R. 7017.1090]
COMG 7	2280	1363372	QA Plan: Develop and implement a written quality assurance plan that covers each CEMS. The plan must be on site and available for inspection within 30 days after monitor certification. The plan must contain all of the information required by 40 CFR Part 60, Appendix F, Section 3. The plan must include the manufacturer's spare parts list for each CEMS and require that those parts be kept at the facility unless the Commissioner gives written approval to exclude specific spare parts from the list. [40 CFR pt. 60, Appendix F, 3, Minn. R. 7017.1010, subp. 1(C), Minn. R. 7017.1170, subp. 2]
COMG 7	2290	1363373	CEMS QA/QC: The Permittee is subject to the performance specifications listed in 40 CFR pt. 60, Appendix B and shall operate, calibrate, and maintain each CEMS according to the QA/QC procedures in 40 CFR pt. 60, Appendix F as amended and maintain a written QA/QC program available in a form suitable for inspection. [40 CFR 60.13(a), 40 CFR pt. 60, Appendix F, Minn. R. 7017.1010, subp. 1(A)]
COMG 7	2300	1363374	CEMS Daily Calibration Drift Test: Check the zero (low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily. The zero and span must, at a minimum, be adjusted whenever the drift exceeds two times the limit specified in 40 CFR pt. 60, Appendix B. 40 CFR pt. 60, Appendix F, Section 4.3.1 must be used to determine out-of-control periods for CEMS. [40 CFR 60.13(d)(1), 40 CFR pt. 60, Appendix F, 4.1, Minn. R. 7017.1010, subp. 1(A), Minn. R. 7017.1170, subp. 3]
COMG 7	2310	1363375	Recordkeeping: The Permittee shall retain records of all CEMS monitoring data and support information for a period of five years from the date of the monitoring sample, measurement or report. Records shall be kept at the source. [40 CFR 60.7(f), Minn. R. 7017.1130, Minn. R. 7019.0100, subp. 1]
COMG 7	2320	1363376	CEMS Monitor Design: Each CEMS shall be designed to complete a minimum of one cycle of sampling, analyzing, and data recording in each 15-minute period. [40 CFR 60.13(e)(2), Minn. R. 7017.1010, subp. 1(A)]
COMG 7	2350	1376496	The Permittee must submit start-up notification: Due 10 working days after Startup of Monitor Date. [Minn. R. 7007.0800, subp. 2(A)]
COMG 7	2360	1440490	CEMS Certification/Recertification Test: due 90 days after the first excess emissions report required for the CEMS or any change which invalidates the monitor's certification status as outlined in Minn. R. 7017.1050, subp. 2. [40 CFR 60.13(b), Minn. R. 7017.1010, subp. 1(A)]
COMG 7	2650	1440498	Installation Notification: due 60 days before installing the continuous emissions monitoring system. The notification shall include plans and drawings of the system. [Minn. R. 7017.1040, subp. 1]
COMG 8	20760	1524093	Transport Rule (TR) NOx Annual Trading Program Requirements. The Permittee shall comply with the TR NOx Annual Trading Program requirements contained in Appendix F. [40 CFR 97.430-435]
COMG 8	20770	1501097	Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418. [40 CFR 97.406(a)]

SI Id	Sequence	ID	Requirement
COMG 8	20780	1501098	TR NOx Emissions monitoring, reporting, and recordkeeping requirements. 1) The owners and operators and the designated representative of each TR NOx Annual source and each TR NOx Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 40 CFR 97.431 (initial monitoring system certification and recertification procedures), 40 CFR 97.432 (monitoring system out-of-control periods), 40 CFR 97.433 (notifications concerning monitoring), 40 CFR 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 40 CFR 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements). 2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of TR NOx Annual allowances under 40 CFR 97.411(a)(2) and (b) and 40 CFR 97.412 and to determine compliance with the TR NOx Annual emissions limitation and assurance provisions under paragraph 40 CFR 97.406(c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. [40 CFR 97.406(b)]
COMG 8	20790	1501099	TR NOx Annual emissions limitation. i) As of the allowance transfer deadline (midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day)) for a control period in a given year, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit at the source shall hold, in the source's compliance account, TR NOx Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NOx emissions for such control period from all TR NOx Annual units at the source. ii) If total NOx emissions during a control period in a given year from the TR NOx Annual units at a TR NOx Annual source are in excess of the TR NOx Annual emissions limitation set forth in 40 CFR 97.406(c)(1)(i) above, then: A) The owners and operators of the source and each TR NOx Annual unit at the source shall hold the TR NOx Annual allowances required for deduction under 40 CFR 97.424(d); and B) The owners and operators of the source and each TR NOx Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act. [40 CFR 97.406(c)(1)]
COMG 8	20800	1501100	TR NOx Annual assurance provisions. i) If total NOx emissions during a control period in a given year from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within the borders of Minnesota exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NOx emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR NOx Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— A) The quotient of the amount by which the common designated representative's share of such NOx emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the Minnesota and Indian country within the borders of Minnesota for such control period, by which each common designated representative's share of such NOx emissions exceeds the respective common designated representative's assurance level; and B) The amount by which total NOx emissions from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within the borders of Minnesota for such control period exceed the state assurance level. ii) The owners and operators shall hold the TR NOx Annual allowances required under 40 CFR 97.406(c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period. iii) Total NOx emissions from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within in the borders of Minnesota during a control period in a given year exceed the state assurance level if such total NOx emissions exceed the sum, for such control period, of the state NOx Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

SI Id	Sequence	ID	Requirement
			iv) It shall not be a violation of 40 CFR part 97, subpart AAAAA or of the Clean Air Act if total NOx emissions from all TR NOx Annual units at TR NOx Annual sources in Minnesota and Indian country within the borders of Minnesota during a control period exceed the state assurance level or if a common designated representative's share of total NOx emissions from the TR NOx Annual units at TR NOx Annual sources in the Minnesota and Indian country within the borders of Minnesota during a control period exceeds the common designated representative's assurance level. v) To the extent the owners and operators fail to hold TR NOx Annual allowances for a control period in a given year in accordance with 40 CFR 97.406(c)(2)(i) through (iii) above, A. The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and B. Each TR NOx Annual allowance that the owners and operators fail to hold for such control period in accordance with 40 CFR 97.406(c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart AAAAA and the Clean Air Act. [40 CFR 97.406(c)(2)(i)-(v)]
COMG 8	20810	1501101	Compliance periods. i) A TR NOx Annual unit shall be subject to the requirements under 40 CFR 97.406(c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter. ii) A TR NOx Annual unit shall be subject to the requirements under 40 CFR 97.406(c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter. [40 CFR 97.406(c)(3)]
COMG 8	20820	1501102	Vintage of allowances held for compliance. i) A TR NOx Annual allowance held for compliance with the requirements under 40 CFR 97.406(c)(1)(i) above for a control period in a given year must be a TR NOx Annual allowance that was allocated for such control period or a control period in a prior year. ii) A TR NOx Annual allowance held for compliance with the requirements under 40 CFR 97.406(c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a TR NOx Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year. [40 CFR 97.406(c)(4)]
COMG 8	20830	1094784	Allowance Management System requirements. Each TR NOx Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart AAAAA. [40 CFR 97.406(c)(5)]
COMG 8	20840	1094785	Limited authorization. A TR NOx Annual allowance is a limited authorization to emit one ton of NOx during the control period in one year. Such authorization is limited in its use and duration as follows: i) Such authorization shall only be used in accordance with the TR NOx Annual Trading Program; and ii) Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act. [40 CFR 97.406(c)(6)]
COMG 8	20850	1094786	Property right. A TR NOx Annual allowance does not constitute a property right. [40 CFR 97.406(c)(7)]
COMG 8	20860	1501103	Additional recordkeeping and reporting requirements. 1) Unless otherwise provided, the owners and operators of each TR NOx Annual source and each TR NOx Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator. i) The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each TR NOx Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative. ii) All emissions monitoring information, in accordance with 40 CFR part 97, subpart AAAAA. iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR NOx Annual Trading Program. 2) The designated representative of a TR NOx Annual source and each TR NOx Annual unit at the source shall make all submissions required under the TR NOx Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71. [40 CFR 97.406(e)]

SI Id	Sequence	ID	Requirement
COMG 8	20870	1094788	Liability. 1) Any provision of the TR NOx Annual Trading Program that applies to a TR NOx Annual source or the designated representative of a TR NOx Annual source shall also apply to the owners and operators of such source and of the TR NOx Annual unit shall also apply to the owners and operators of such unit. 2) Any provision of the TR NOx Annual Trading Program that applies to a TR NOx Annual unit or the designated representative of a TR NOx Annual unit shall also apply to the owners and operators of such unit. [40 CFR 97.406(f)]
COMG 8	20880	1501104	Effect on other authorities. No provision of the TR NOx Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR NOx Annual source or TR NOx Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act. [40 CFR 97.406(g)]
COMG 8	20890	1524094	Transport Rule (TR) SO2 Group 2 Trading Program Requirements. The Permittee shall comply with the TR SO2 Group 2 Trading Program Requirements contained in Appendix F. [40 CFR 97.730-735]
COMG 8	20900	1501105	Designated representative requirements. The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.713 through 97.718. [40 CFR 97.706(a)]
COMG 8	20910	1501106	TR SO2 Group 2 Emissions monitoring, reporting, and recordkeeping requirements. 1) The owners and operators, and the designated representative, of each TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.730 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 40 CFR 97.731 (initial monitoring system certification and recertification procedures), 40 CFR 97.732 (monitoring system out-of-control periods), 40 CFR 97.733 (notifications concerning monitoring), 40 CFR 97.734 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 40 CFR 97.735 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements). 2) The emissions data determined in accordance with 40 CFR 97.730 through 97.735 shall be used to calculate allocations of TR SO2 Group 2 allowances under 40 CFR 97.711(a)(2) and (b) and 40 CFR 97.712 and to determine compliance with the TR SO2 Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.730 through 97.735 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. [40 CFR 97.706(b)]
COMG 8	20920	1501107	TR SO2 Group 2 emissions limitation. i) As of the allowance transfer deadline (midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day)) for a control period in a given year, the owners and operators of each TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall hold, in the source's compliance account, TR SO2 Group 2 allowances available for deduction for such control period under 40 CFR 97.724(a) in an amount not less than the tons of total SO2 emissions for such control period from all TR SO2 Group 2 units at the source. ii) If total SO2 emissions during a control period in a given year from the TR SO2 Group 2 units at a TR SO2 Group 2 source are in excess of the TR SO2 Group 2 emissions limitation set forth in paragraph 40 CFR 97.706(c)(1)(i) above, then: A) The owners and operators of the source and each TR SO2 Group 2 unit at the source shall hold the TR SO2 Group 2 allowances required for deduction under 40 CFR 97.724(d); and B) The owners and operators of the source and each TR SO2 Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart DDDDD and the Clean Air Act. [40 CFR 97.706(c)(1)]

SI Id	Sequence	ID	Requirement
COMG 8	20930	1501108	TR SO2 Group 2 assurance provisions. i) If total SO2 emissions during a control period in a given year from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO2 Group 2 allowances available for deduction for such control period under 40 CFR 97.725(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.725(b), of multiplying— A) The quotient of the amount by which the common designated representative's share of such SO2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in Minnesota and Indian country within the borders of Minnesota for such control period, by which each common designated representative's share of such SO2 emissions exceeds the respective common designated representative's assurance level; and B) The amount by which total SO2 emissions from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota for such control period exceed the state assurance level. ii) The owners and operators shall hold the TR SO2 Group 2 allowances required under 40 CFR 97.706(c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period. iii) Total SO2 emissions from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota during a control period in a given year exceed the state assurance level if such total SO2 emissions exceed the sum, for such control period, of the state SO2 Group 2 trading budget under 40 CFR 97.710(a) and the state's variability limit under 40 CFR 97.710(b).
			iv) It shall not be a violation of 40 CFR part 97, subpart DDDDD or of the Clean Air Act if total SO2 emissions from all TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota during a control period exceed the state assurance level or if a common designated representative's share of total SO2 emissions from the TR SO2 Group 2 units at TR SO2 Group 2 sources in Minnesota and Indian country within the borders of Minnesota during a control period exceeds the common designated representative's assurance level. v) To the extent the owners and operators fail to hold TR SO2 Group 2 allowances for a control period in a given year in accordance with 40 CFR 97.706(c)(2)(i) through (iii) above, A.) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and B.) Each TR SO2 Group 2 allowance that the owners and operators fails to hold for such control period in accordance with 40 CFR 97.706(c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart DDDDD and the Clean Air Act. [40 CFR 97.706(c)(2)(i)-(v)]
COMG 8	20940	1501109	Compliance Periods. i) A TR SO2 Group 2 unit shall be subject to the requirements under 40 CFR 97.706(c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.730(b) and for each control period thereafter ii) A TR SO2 Group 2 unit shall be subject to the requirements under 40 CFR 97.706(c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.730(b) and for each control period thereafter. [40 CFR 97.706(c)(3)]
COMG 8	20950	1501110	Vintage of allowances held for compliance. i) A TR SO2 Group 2 allowance held for compliance with the requirements under 40 CFR 97.706(c)(1)(i) above for a control period in a given year must be a TR SO2 Group 2 allowance that was allocated for such control period or a control period in a prior year. ii) A TR SO2 Group 2 allowance held for compliance with the requirements under 40 CFR 97.706(c)(1)(ii)(A) and (c)(2)(i) through (iii) above for a control period in a given year must be a TR SO2 Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year. [40 CFR 97.706(c)(4)]
COMG 8	20960	1094797	Allowance Management System requirements. Each TR SO2 Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, subpart DDDDD. [40 CFR 97.706(c)(5)]

SI Id	Sequence	ID	Requirement
COMG 8	20970	1094798	Limited authorization. A TR SO2 Group 2 allowance is a limited authorization to emit one ton of SO2 during the control period in one year. Such authorization is limited in its use and duration as follows: i) Such authorization shall only be used in accordance with the TR SO2 Group 2 Trading Program; and ii) Notwithstanding any other provision of 40 CFR part 97, subpart DDDDD, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act. [40 CFR 97.706(c)(6)]
COMG 8	20980	1094799	Property right. A TR SO2 Group 2 allowance does not constitute a property right. [40 CFR 97.706(c)(7)]
COMG 8	20990	1501111	Additional recordkeeping and reporting requirements. 1) Unless otherwise provided, the owners and operators of each TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator. i) The certificate of representation under 40 CFR 97.716 for the designated representative for the source and each TR SO2 Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.716 changing the designated representative. ii) All emissions monitoring information, in accordance with 40 CFR part 97, subpart DDDDD. iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO2 Group 2 Trading Program. 2) The designated representative of a TR SO2 Group 2 source and each TR SO2 Group 2 unit at the source shall make all submissions required under the TR SO2 Group 2 Trading Program, except as provided in 40 CFR 97.718. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71. [40 CFR 97.706(e)]
COMG 8	21000	1094801	Liability. 1) Any provision of the TR SO2 Group 2 Trading Program that applies to a TR SO2 Group 2 source or the designated representative of a TR SO2 Group 2 source shall also apply to the owners and operators of such source and of the TR SO2 Group 2 units at the source. 2) Any provision of the TR SO2 Group 2 Trading Program that applies to a TR SO2 Group 2 unit or the designated representative of a TR SO2 Group 2 unit shall also apply to the owners and operators of such unit. [40 CFR 97.706(f)]
COMG 8	21010	1501112	Effect on other authorities. No provision of the TR SO2 Group 2 Trading Program or exemption under 40 CFR 97.705 shall be construed as exempting or excluding the owners or operators, and the designated representative, of a TR SO2 Group 2 source or TR SO2 Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act. [40 CFR 97.706(g)]
COMG 9	2410	1440492	Additional monitoring requirements may apply. The Permittee is responsible for meeting all applicable requirements. [Minn. R. 7007.0800, subp. 4(A)]
COMG 9	2420	1544766	Emissions Monitoring: The owner or operator shall use a CEMS to measure emissions from EQUI 7 and EQUI 8. [40 CFR 75.10(a)]
COMG 9	2430	1531212	Certification Application: The Permittee shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The Permittee shall submit the certification application in accordance with 40 CFR 75.60 and each complete certification application shall include the information specified in 40 CFR 75.60 and 40 CFR 75.63. [40 CFR 75.20(a)(2), 40 CFR 75.60(b)(1), 40 CFR 75.63]
COMG 9	2440	1531213	Monitoring Data: Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data is unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to 40 CFR 75.21 and appendix B of 40 CFR pt. 75, or backups of data from the data acquisition and handling system, or recertification, pursuant to 40 CFR 75.20. The Permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. [40 CFR 75.10(d)(1)]
COMG 9	2450	1265233	CEMS QA/QC: The owner or operator of an affected facility shall operate, calibrate, and maintain each CEMS according to the QA/QC procedures in 40 CFR pt. 75, Appendix B as amended. [40 CFR 75.21(a)]

SI Id	Sequence	ID	Requirement
COMG 9	2490	1531214	Quarterly Reports: Electronically report the data and information in 40 CFR 75.64(a), (b), and (c) to the Administrator quarterly. [40 CFR 75.64]
COMG 9	2500	1531215	Recordkeeping: The Permittee shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. The file shall contain all information required by 40 CFR 75.57. [40 CFR 75.57]
COMG 9	2555	1326717	Daily Calibration error (CE) Test: conduct daily CE testing on all CEMS required by the Acid Rain Program, in accordance with 40 CFR pt. 75, appendix B. [40 CFR pt. 75, Appendix B(Sect 2.1)]
COMG 9	2650	1440498	Installation Notification: due 60 days before installing the continuous emissions monitoring system. The notification shall include plans and drawings of the system. [Minn. R. 7017.1040, subp. 1]
EQUI 1	1	1525641	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 1. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 1	3080	1525648	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
EQUI 1	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 1	3535	1330950	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 1	3540	1330951	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
EQUI 1	3560	1030835	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
EQUI 1	3565	1347393	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]
EQUI 1	20045	1371534	Opacity: The Permittee shall conduct a performance test due before 03/20/2020 and every 48 calendar months thereafter to measure opacity. The deadline for the first test is extended to 07/18/2020. Subsequent tests are due by 03/20/2024 and every 48 months thereafter. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter. Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 2	1	1525644	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 2. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 2	3080	1525650	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
EQUI 2	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 2	3535	1330952	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]

SI Id	Sequence	ID	Requirement
EQUI 2	3540	1330953	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
EQUI 2	3560	1030835	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
EQUI 2	3565	1347398	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]
EQUI 2	20045	1330977	Opacity: The Permittee shall conduct a performance test due before 03/12/2021 and every 48 calendar months thereafter to measure opacity. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter. Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 3	1	1525643	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 3. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 3	3080	1525651	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
EQUI 3	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 3	3535	1330954	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 3	3540	1330955	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
EQUI 3	3560	1030835	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
EQUI 3	3565	1347399	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
EQUI 3	20045	1330976	Opacity: The Permittee shall conduct a performance test due before 04/15/2022 and every 48 calendar months thereafter to measure opacity. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter. Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 4	1	1525642	The requirements below will no longer be applicable following receipt of a notification of equipment removal/dismantlement for EQUI 4. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 4	3080	1525652	The Permittee shall submit a notification of equipment removal/dismantlement: Due 15 calendar days after Equipment Removal and/or Dismantlement Date. This notification shall specify which Subject Items (by ID#) were removed and on what date. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B)]
EQUI 4	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 4	3535	1330956	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 4	3540	1330957	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
EQUI 4	3560	1030835	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
EQUI 4	3565	1347400	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. The certification may be a single annual certification from the fuel oil supplier guaranteeing maximum sulfur content in all fuel oil deliveries thereafter. The single certification shall also state that the supplier will notify the Permittee in writing on the date of delivery of fuel oil with a sulfur content exceeding the guaranteed maximum, that the fuel oil sulfur content exceeds the guaranteed maximum value. [Minn. R. 7007.0800, subps. 4-5]
EQUI 4	20045	1330975	Opacity: The Permittee shall conduct a performance test due before 03/29/2023 and every 48 calendar months thereafter to measure opacity. The first test is due by the date specified above and all subsequent tests shall be completed every 60 months thereafter by the due date (month and day) and as described below. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 9, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to the performance test due date will not reset the test due date for future testing as required by this permit or within a Notice of Compliance letter. Testing conducted more than 60 days prior to the performance test due date satisfies this test due date requirement but will reset future performance test due dates based on the performance test date. [Minn. R. 7017.2020, subp. 1]
EQUI 5	39	1343542	The Permittee is subject to pt. 63, subp. ZZZZ because it owns and operates EQUI 5 (a stationary RICE) located at an area HAP emissions source, and EQUI 5 is not being tested at a stationary RICE test cell/stand. [40 CFR 63.6585, Minn. R. 7011.8150]
EQUI 5	42	1343553	EQUI 5 is an existing 175 hp compression ignition stationary RICE installed in 1993 subject to 40 CFR pt. 63, subp. ZZZZ because it has a site rating of equal to or less than 500 brake HP, is located at an area HAP emissions source, and the Permittee commenced construction of EQUI 5 before June 12, 2006. [40 CFR 63.6590(a)(1)(iii), Minn. R. 7011.8150]
EQUI 5	43	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]

SI Id	Sequence	ID	Requirement
EQUI 5	3520	1330960	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 5	3535	1330961	Fuel type: Distillate fuel with sulfur content less than 0.0015 percent by weight. [Minn. R. 7005.0100, subp. 35a]
EQUI 5	3540	1030834	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, limiting operation to 500 hours per year. [Minn. R. 7007.0800, subps. 4-5]
EQUI 5	3550	1030835	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5]
EQUI 5	3560	1544230	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5]
EQUI 5	3565	1330963	The Permittee must comply with all applicable requirements of 40 CFR pt. 63, subp. ZZZZ as follows: 40 CFR 63.6585(a), 40 CFR 63.6585(c), 40 CFR 63.6585(d), 40 CFR 63.6590 (a)(1)(iii), 40 CFR 63.6595(a), 40 CFR 63.6603(a), 40 CFR 63.6605(a), 40 CFR 63.6605(b), 40 CFR 63.6625 (e)(3), 40 CFR 63.6625(f), 40 CFR 63.6625(h), 40 CFR 63.6625(i), 40 CFR 63.6640(a), 40 CFR 63.6640(b), 40 CFR 63.6640 (e), 40 CFR 63.6640(f), 40 CFR 63.6640(f)(1), 40 CFR 63.6640(f)(2)(i), 40 CFR 63.6640(f)(4), 40 CFR 63.6650(f), 40 CFR 63.6655(a)(1)-(2), 40 CFR 63.6655(e), 40 CFR 63.6655(f),
			40 CFR 63.6660, 40 CFR 63.6665, 40 CFR 63.6675, 40 CFR pt. 63, subp ZZZZ Table 2(d)(Item 4), 40 CFR pt. 63, subp ZZZZ Table 6 (item 9), 40 CFR pt. 63, subp ZZZZ Table 8. A copy of 40 CFR pt. 63, subp. ZZZZ is included in Appendix E. If the applicable sections of the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 63, subp. ZZZZ, Minn. R. 7011.8150]

SI Id	Sequence	ID	Requirement
			The Permittee must comply with all applicable requirements of 40 CFR pt. 63, subp. A as follows: 40 CFR 63.1(a); 40 CFR 63.1(b)(1); 40 CFR 63.1(b)(3); 40 CFR 63.1(c)(1); 40 CFR 63.1(c)(2); 40 CFR 63.1(c)(5); 40 CFR 63.1(e); 40 CFR 63.2; 40 CFR 63.3; 40 CFR 63.4; 40 CFR 63.5(a); 40 CFR 63.5(b); 40 CFR 63.5(d); 40 CFR 63.5(e); 40 CFR 63.5(f); 40 CFR 63.6(a)(1); 40 CFR 63.6(a)(2); 40 CFR 63.6(c)(1); 40 CFR 63.6(c)(2);
EQUI 5	19505	1330962	40 CFR 63.6(c)(5);
			40 CFR 63.6(i)(1); 40 CFR 63.6(i)(2); 40 CFR 63.6(i)(3); 40 CFR 63.6(i)(4); 40 CFR 63.6(i)(6); 40 CFR 63.6(i)(8); 40 CFR 63.6(i)(9); 40 CFR 63.6(i)(11); 40 CFR 63.6(j); 40 CFR 63.7(a)(2); 40 CFR 63.7(a)(2)(ix); 40 CFR 63.7(a)(3); 40 CFR 63.7(a)(4); 40 CFR 63.7(b); 40 CFR 63.7(c); 40 CFR 63.7(d); 40 CFR 63.7(f); 40 CFR 63.7(g); 40 CFR 63.7(h); 40 CFR 63.8(b)(1); 40 CFR 63.8(g); 40 CFR 63.9(b)(1); 40 CFR 63.9(b)(2); 40 CFR 63.9(b)(4); 40 CFR 63.9(c); 40 CFR 63.9(e); 40 CFR 63.9(h);

SI Id	Sequence	ID	Requirement
			40 CFR 63.9(i); 40 CFR 63.9(j); 40 CFR 63.10(a)(5); 40 CFR 63.10(a)(6); 40 CFR 63.10(a)(7); 40 CFR 63.10(b)(1); 40 CFR 63.10(b)(2)(ix); 40 CFR 63.10(b)(2)(xii); 40 CFR 63.10(b)(2)(xiii); 40 CFR 63.10(b)(2)(xiv); 40 CFR 63.10(b)(3); 40 CFR 63.10(d)(1); 40 CFR 63.10(d)(2); 40 CFR 63.10(d)(4); 40 CFR 63.10(f); 40 CFR 63.12; 40 CFR 63.13; 40 CFR 63.14; 40 CFR 63.15(a); 40 CFR 63.15(b). A copy of 40 CFR pt. 63, subp. A is included in Appendix D. If the applicable sections of the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 63, subp. A, 40 CFR pt. 63, subp. ZZZZ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.7000, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 5	21040	1525808	Temporary replacement conditions: The Permittee may temporarily replace this unit (EQUI 5), provided the following conditions are met: 1) The potential emissions of the replacement unit (including the effect of all enforceable limits imposed through this permit) are less than all of the following: 25 tpy PM, 15 tpy PM < 10 microns, 10 tpy PM < 2.5 microns, 40 tpy VOC, 40 tpy SO2, 40 tpy NOx, 100 tpy CO, 75000 tpy CO2e; 2) For pollutants not specifically limited by a permit or rule, the Permittee shall calculate emissions using an emission factor provided by the temporary replacement engine manufacturer if available, or from AP-42 if not available; 3) The heat input capacity of the replacement unit is less than or equal to the unit it replaces; 4) The project can only be the temporary replacement of an internal combustion engine(s) for the purpose of providing emergency electrical power at the facility; 5) Emissions and operating hours are tracked and calculated as specified in this permit; 6) The replacement engine may only replace a permanent engine that is temporarily out of service for less than one year; 7) The replacement engine must meet the conditions for temporary replacement units under 40 CFR Section 60.4200(e); 8) Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment. The Permittee is not required to complete emission calculations described in Minn. R. 7007.1200 subp. 2. A permit will still be needed regardless of the emissions increase if the change will be subject to a new applicable requirement or requires revisions to the limits or monitoring and recordkeeping in this permit. [40 CFR 60.4200(e), Minn. R. 7005.0100, subp. 35a, Minn. R. 7007.0800, Minn. R. 7007.1200, subp. 3, Minn. R. 7011.2305, Title I Condition: Avoid major modification under 40 CFR 52.21(b)(2) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 5	21041	1333644	If installation of the temporary replacement engine does not require a permit amendment, the Permittee shall keep the following records on site for each replacement engine not requiring a permit amendment: - Records required by Minn. R. 7007.1200, subp. 4; - The dates the temporary engine was installed, started operation, and was removed; - Filled form GI05B for each replacement engine with an assigned consecutive emission unit number; - A unique identification for the unit, such as make, model, and serial number; - Rated capacity and type of engine; - Dates and hours of operation of the engine; - A statement of all periods of operation during which the permanent engine being temporarily replaced is not also operating; and - Calculations of the potential to emit of the engine and emission changes pursuant to Minn. R. 7007.1200 subpart 3. [Minn. R. 7007.0800, subp. 5, Minn. R. 7007.1200, subp. 4, Title I Condition: Avoid major modification under 40 CFR 52.21(b)(2) and Minn. R. 7007.3000]
EQUI 5	21042	1333645	The Permittee shall notify the MPCA if the replacement engine is operated simultaneously with the permanent engine being temporarily replaced, except as allowed by this permit. Make verbal notification within 2 days, and written notification with the semi-annual deviations report. [Minn. R. 7007.0800, subp. 5, Minn. R. 7007.1200, subp. 4]
EQUI 7	1	1524097	EQUI 7 is subject to the U.S. EPA Acid Rain Program codified at 40 CFR Parts 72 and 75. EQUI 7 meets the definitions of utility unit, new unit, and gas-fired unit, as defined in 40 CFR 72.2. Some of the Acid Rain Program requirements are included in this permit for MPCA tracking purposes. The Permittee submitted a copy of their Acid Rain Permit Application with the reissuance application submitted on 03/22/2019. The Acid Rain Permit Application can be found in Appendix B of this permit. [40 CFR pt. 72]
EQUI 7	2	1524098	If EQUI 7 has excess emissions as defined in STEP 3 of the Acid Rain Permit Application found in Appendix B of this permit, the designated representative shall submit a proposed offset plan in accordance with 40 CFR 72.9(e). [40 CFR 72.9(e), Minn. R. 7007.1075]
EQUI 7	3	1544546	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and continues until Mode 6 is attained. 2. Shutdown begins when the shutdown sequence is initiated and the unit leaves Mode 6. 3. Emergency operation occurs when the unit is not in Mode 6 but shutdown has not been initiated. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	4	1524787	The Permittee must limit emissions of Particulate Matter <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	5	1524788	The Permittee must limit emissions of Particulate Matter <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	6	1524789	The Permittee must limit emissions of PM < 10 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	7	1524790	The Permittee must limit emissions of PM < 10 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	8	1524791	The Permittee must limit emissions of PM < 2.5 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	9	1524793	The Permittee must limit emissions of PM < 2.5 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 7	10	1524794	The Permittee must limit emissions of Nitrogen Oxides <= 11 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	11	1524795	The Permittee must limit emissions of Nitrogen Oxides <= 73.51 pounds per hour 24-hour rolling average. This limit applies during normal operation. Normal operation commences upon initial attainment of Mode 6 operation. Mode 6 operation occurs when all burner nozzles are firing in low-NOx configuration. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 7	12	1536270	The Permittee must limit emissions of Nitrogen Oxides <= 6.76 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 68 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	13	1536271	The Permittee must limit emissions of Nitrogen Oxides <= 7.29 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 304 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 7	14	1524834	The Permittee must limit emissions of Nitrogen Oxides <= 110 parts per million 3-hour average by volume on a dry basis corrected to 15 percent oxygen. This limit applies at all times except during startup, shutdown or malfunction. [40 CFR 60.332, Minn. R. 7011.2350]
EQUI 7	15	1524806	The Permittee must limit emissions of Carbon Monoxide <= 9 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	16	1524807	The Permittee must limit emissions of Carbon Monoxide <= 38.80 pounds per hour 24-hour rolling average. This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	17	1536272	The Permittee must limit emissions of Carbon Monoxide <= 18.01 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 180 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	18	1536273	The Permittee must limit emissions of Carbon Monoxide <= 11.47 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 478 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	19	1524808	The Permittee must limit emissions of Volatile Organic Compounds <= 4.6 parts per million 3-hour block average (dry basis) at actual O2 (as methane). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	20	1524809	The Permittee must limit emissions of Volatile Organic Compounds <= 10.03 pounds per hour 3-hour average (as methane). This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	21	1536274	The Permittee must limit emissions of Volatile Organic Compounds <= 8.64 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 86 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	22	1536275	The Permittee must limit emissions of Volatile Organic Compounds <= 24.95 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 1040 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	23	1524837	The Permittee must limit emissions of Sulfur Dioxide <= 0.015 percent by volume at 15 percent oxygen and on a dry basis, or Sulfur Content of Fuel: less than or equal to 0.8 percent by weight. [40 CFR 60.333, Minn. R. 7011.2350]
EQUI 7	24	1524831	The Permittee must limit emissions of Carbon Dioxide <= 110 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	25	1524832	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 986,539 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	26	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 7	27	1330964	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 7	28	1525676	Fuel type: Pipeline natural gas, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	29	1532733	Daily Recordkeeping. On each day of operation, the Permittee shall calculate and record the total EQUI 7 fuel usage. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subp. 5]
EQUI 7	30	1532073	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	31	1524099	CO Monitoring: The Permittee shall monitor CO emissions on both a lb/mmBtu and a lb/hr basis using any of the following methods: 1. A CO CEMS on EQUI 7 stack/vent (STRU 12) to monitor CO emissions as described by this permit. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
EQUI 7	32	1524100	SO2 Emissions Monitoring: The Permittee shall monitor SO2 according to 40 CFR Part 75 Appendix D Sections 2.1, 2.3, 2.4, 3.3, 3.4, and 3.5. The Permittee shall use the hourly SO2 emissions calculated according to 40 CFR Part 75 Appendix D, Section 3.3 to determine daily, monthly, and 12-month rolling sum (ton per year) EQUI 7 SO2 emissions. If the Permittee becomes eligible, the Permittee may use the low mass emission (LME) excepted methodology described in 40 CFR 75.19(c)(1)(ii) to determine SO2 emissions. Since the Permittee elected not to install a SO2 CEMS, the Permittee shall determine SO2 emissions in lb/mmBtu, according to 40 CFR Part 75 Appendix D - Optional SO2 emissions Data Protocol For Gas-fired and Oil-fired Units, or, if eligible, according to 40 CFR 75.19(c)(1)(ii). [40 CFR pt. 75, Appendix D, Minn. R. 7007.0800, subps. 4-5]
EQUI 7	33	1524101	The Permittee is not required to use Continuous Emission Monitoring Systems (CEMS) for sulfur dioxide provided the Permittee complies with the requirements of 40 CFR Part 75 Appendix D or 40 CFR 75.19(c)(1)(ii). [40 CFR 75.10(a)(1), 40 CFR 75.11(d)(2) and (3)]
EQUI 7	36	1524104	Fuel Monitoring: The Permittee shall follow the applicable fuel sulfur and nitrogen content monitoring requirements in 40 CFR 60.334(h) and monitor at the frequency specified in 40 CFR 60.334(i). [40 CFR 60.334(h) and (i), Minn. R. 7007.0800, subp. 4, Minn. R. 7011.2350]
EQUI 7	40	1524109	Monthly Recordkeeping. CO Emissions: By the 15th of the month, the Permittee shall calculate and record the EQUI 7 CO emissions for the previous calendar month (in tons per month) using one of the following methods: 1. A CO CEMS to determine hourly CO lb/hr emissions for each hour of operation; or 2. Hourly CO lb/hr emissions data for each hour of operation based on fuel usage and the appropriate AP-42 emission factor and hourly heat input. 3. Approved emission factors for calculating CO emissions are the CO factor in EPA's AP-42 chapter 3.1, Table 3.1-1 for Natural Gas-Fired lean-premix turbines. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subps. 4-5]
EQUI 7	41	1528200	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 7. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MNG * 110) + ((MNG * 0.0086) * 25) + ((MNG * 0.00022) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0086 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 7 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	42	1536276	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 200 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	43	1536277	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 7 while operating in emergency mode. Sum the number of hours EQUI 7 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	44	1536871	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 7	45	1536872	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	46	1536873	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 7	4609	1339477	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1(a); 40 CFR 60.1(b); 40 CFR 60.1(c); 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5(a); 40 CFR 60.5(b); 40 CFR 60.6(a); 40 CFR 60.6(b); 40 CFR 60.7(a)(1); 40 CFR 60.7(a)(3); 40 CFR 60.7(a)(4); 40 CFR 60.7(a)(5); 40 CFR 60.7(b); 40 CFR 60.7(c); 40 CFR 60.7(d); 40 CFR 60.8(a); 40 CFR 60.8(b); 40 CFR 60.8(c); 40 CFR 60.8(d); 40 CFR 60.8(e); 40 CFR 60.8(f); 40 CFR 60.8(g); 40 CFR 60.8(h);
			40 CFR 60.8(i); 40 CFR 60.9; 40 CFR 60.11(a); 40 CFR 60.11(d); 40 CFR 60.11(f); 40 CFR 60.11(g); 40 CFR 60.12; 40 CFR 60.13(a); 40 CFR 60.13(b); 40 CFR 60.13(c); 40 CFR 60.13(d)(1); 40 CFR 60.13(e)(2); 40 CFR 60.13(f); 40 CFR 60.13(g); 40 CFR 60.13(h)(2); 40 CFR 60.13(h)(3); 40 CFR 60.13(i)(1); 40 CFR 60.13(i)(2); 40 CFR 60.13(i)(3); 40 CFR 60.13(i)(4); 40 CFR 60.13(i)(5); 40 CFR 60.13(i)(6); 40 CFR 60.13(i)(7); 40 CFR 60.13(i)(8); 40 CFR 60.13(i)(9); 40 CFR 60.13(j)(1); 40 CFR 60.13(j)(2);

SI Id	Sequence	ID	Requirement
			40 CFR 60.14(a); 40 CFR 60.14(b); 40 CFR 60.14(c); 40 CFR 60.14(e); 40 CFR 60.14(f); 40 CFR 60.14(g); 40 CFR 60.14(h); 40 CFR 60.14(i); 40 CFR 60.14(j); 40 CFR 60.15(a); 40 CFR 60.15(b); 40 CFR 60.15(c); 40 CFR 60.15(d); 40 CFR 60.15(e); 40 CFR 60.15(f); 40 CFR 60.15(g); 40 CFR 60.17; 40 CFR 60.19(a); 40 CFR 60.19(b); 40 CFR 60.19(c); 40 CFR 60.19(d); 40 CFR 60.19(e); 40 CFR 60.19(f)(1); 40 CFR 60.19(f)(2); 40 CFR 60.19(f)(3); and 40 CFR 60.19(f)(4).
			A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the applicable sections of the standard change or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. GG, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2350, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 7	19880	1525610	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 7	19890	1525609	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 7	19900	1525605	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 7	19940	1527344	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	1	1524110	EQUI 8 is subject to the U.S. EPA Acid Rain Program codified at 40 CFR Parts 72 and 75. EQUI 8 meets the definitions of utility unit, new unit, and gas-fired unit, as defined in 40 CFR 72.2. Some of the Acid Rain Program requirements are included in this permit for MPCA tracking purposes. The Permittee submitted a copy of their Acid Rain Permit Application with the reissuance application submitted on 03/22/2019. The Acid Rain Permit Application can be found in Appendix B of this permit. [40 CFR pt. 72]
EQUI 8	2	1524112	If EQUI 8 has excess emissions as defined in STEP 3 of the Acid Rain Permit Application found in Appendix B of this permit, the designated representative shall submit a proposed offset plan in accordance with 40 CFR 72.9(e). [40 CFR 72.9(e), Minn. R. 7007.1075]
EQUI 8	3	1544555	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and continues until Mode 6 is attained. 2. Shutdown begins when the shutdown sequence is initiated and the unit leaves Mode 6. 3. Emergency operation occurs when the unit is not in Mode 6 but shutdown has not been initiated. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	4	1524841	The Permittee must limit emissions of Particulate Matter <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	5	1524842	The Permittee must limit emissions of Particulate Matter <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	6	1524843	The Permittee must limit emissions of PM < 10 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	7	1524844	The Permittee must limit emissions of PM < 10 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	8	1524845	The Permittee must limit emissions of PM < 2.5 micron <= 0.0066 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	9	1524846	The Permittee must limit emissions of PM < 2.5 micron <= 13.48 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 8	10	1524847	The Permittee must limit emissions of Nitrogen Oxides <= 11 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	11	1524848	The Permittee must limit emissions of Nitrogen Oxides <= 73.51 pounds per hour 24-hour rolling average. This limit applies during normal operation. Normal operation commences upon initial attainment of Mode 6 operation. Mode 6 operation occurs when all burner nozzles are firing in low-NOx configuration. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 8	12	1536278	The Permittee must limit emissions of Nitrogen Oxides <= 6.76 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 68 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	13	1536279	The Permittee must limit emissions of Nitrogen Oxides <= 7.29 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 304 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	14	1524858	The Permittee must limit emissions of Nitrogen Oxides <= 110 parts per million 3-hour average by volume on a dry basis corrected to 15 percent oxygen. This limit applies at all times except during startup, shutdown or malfunction. [40 CFR 60.332, Minn. R. 7011.2350]
EQUI 8	15	1524850	The Permittee must limit emissions of Carbon Monoxide <= 9 parts per million 24-hour rolling average (dry basis) corrected to 15% O2 during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	16	1524851	The Permittee must limit emissions of Carbon Monoxide <= 38.80 pounds per hour 24-hour rolling average. This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	17	1536280	The Permittee must limit emissions of Carbon Monoxide <= 18.01 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 180 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	18	1536281	The Permittee must limit emissions of Carbon Monoxide <= 11.47 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 478 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	19	1524853	The Permittee must limit emissions of Volatile Organic Compounds <= 4.6 parts per million 3-hour block average (dry basis) at actual O2 (as methane). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	20	1524854	The Permittee must limit emissions of Volatile Organic Compounds <= 10.03 pounds per hour 3-hour average (as methane). This limit applies during normal operation. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	21	1536282	The Permittee must limit emissions of Volatile Organic Compounds <= 8.64 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 86 lbs per SUSD event. Startup shall last no greater than 23 minutes per event. Shutdown shall last no greater than 11 minutes per event. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	22	1536283	The Permittee must limit emissions of Volatile Organic Compounds <= 24.95 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 1040 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	23	1524856	The Permittee must limit emissions of Sulfur Dioxide <= 0.015 percent by volume at 15 percent oxygen and on a dry basis, or Sulfur Content of Fuel: less than or equal to 0.8 percent by weight. [40 CFR 60.333, Minn. R. 7011.2350]
EQUI 8	24	1524859	The Permittee must limit emissions of Carbon Dioxide <= 110 pounds per million Btu heat input 3-hour rolling average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	25	1524860	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 986,539 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	26	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 8	27	1330968	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 8	28	1525677	Fuel type: Pipeline natural gas, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	29	1532732	Daily Recordkeeping. On each day of operation, the Permittee shall calculate and record the total EQUI 8 fuel usage. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subp. 5]
EQUI 8	30	1532074	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	31	1524114	CO Monitoring: The Permittee shall monitor CO emissions on both a lb/mmBtu and a lb/hr basis using any of the following methods: 1. A CO CEMS on EQUI 8 stack/vent (STRU 13) to monitor CO emissions as described by this permit. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
EQUI 8	32	1524116	SO2 Emissions Monitoring: The Permittee shall monitor SO2 according to 40 CFR Part 75 Appendix D Sections 2.1, 2.3, 2.4, 3.3, 3.4, and 3.5. The Permittee shall use the hourly SO2 emissions calculated according to 40 CFR Part 75 Appendix D, Section 3.3 to determine daily, monthly, and 12-month rolling sum (ton per year) EQUI 8 SO2 emissions. If the Permittee becomes eligible, the Permittee may use the low mass emission (LME) excepted methodology described in 40 CFR 75.19(c)(1)(ii) to determine SO2 emissions. Since the Permittee elected not to install a SO2 CEMS, the Permittee shall determine SO2 emissions in lb/mmBtu, according to 40 CFR Part 75 Appendix D - Optional SO2 emissions Data Protocol For Gas-fired and Oil-fired Units, or, if eligible, according to 40 CFR 75.19(c)(1)(ii). [40 CFR pt. 75, Appendix D, Minn. R. 7007.0800, subps. 4-5]
EQUI 8	33	1524117	The Permittee is not required to use Continuous Emission Monitoring Systems (CEMS) for sulfur dioxide provided the Permittee complies with the requirements of 40 CFR Part 75 Appendix D or 40 CFR 75.19(c)(1)(ii). [40 CFR 75.10(a)(1), 40 CFR 75.11(d)(2) and (3)]
EQUI 8	36	1524121	Fuel Monitoring: The Permittee shall follow the applicable fuel sulfur and nitrogen content monitoring requirements in 40 CFR 60.334(h) and monitor at the frequency specified in 40 CFR 60.334(i). [40 CFR 60.334(h) and (i), Minn. R. 7007.0800, subp. 4, Minn. R. 7011.2350]
EQUI 8	40	1524129	Monthly Recordkeeping. CO Emissions: By the 15th of the month, the Permittee shall calculate and record the EQUI 8 CO emissions for the previous calendar month (in tons per month) using one of the following methods: 1. A CO CEMS to determine hourly CO lb/hr emissions for each hour of operation; or, 2. Hourly CO lb/hr emissions data for each hour of operation based on fuel usage and the appropriate AP-42 emission factor and hourly heat input. 3. Approved emission factors for calculating CO emissions are the CO factor in EPA's AP-42 chapter 3.1, Table 3.1-1 for Natural Gas-Fired lean-premix turbines. [Minn. R. 4410.4300, subp. 15(A) (limit to avoid threshold), Minn. R. 7007.0800, subp. 2(B), Minn. R. 7007.0800, subps. 4-5]
EQUI 8	41	1528201	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 8. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MNG * 110) + ((MNG * 0.0086) * 25) + ((MNG * 0.00022) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0086 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 8 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	42	1536284	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 200 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	43	1536285	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 8 while operating in emergency mode. Sum the number of hours EQUI 8 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	44	1536875	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 8	45	1536876	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	46	1536877	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 8	4609	1339491	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1(a); 40 CFR 60.1(b); 40 CFR 60.1(c); 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5(a); 40 CFR 60.5(b); 40 CFR 60.6(a); 40 CFR 60.6(b); 40 CFR 60.7(a)(1); 40 CFR 60.7(a)(3); 40 CFR 60.7(a)(4); 40 CFR 60.7(a)(5); 40 CFR 60.7(b); 40 CFR 60.7(c); 40 CFR 60.7(d); 40 CFR 60.8(a); 40 CFR 60.8(b); 40 CFR 60.8(c); 40 CFR 60.8(d); 40 CFR 60.8(e); 40 CFR 60.8(f); 40 CFR 60.8(g); 40 CFR 60.8(h); 40 CFR 60.8(i);
			40 CFR 60.9; 40 CFR 60.11(a); 40 CFR 60.11(d); 40 CFR 60.11(f); 40 CFR 60.11(g); 40 CFR 60.12; 40 CFR 60.13(a); 40 CFR 60.13(b); 40 CFR 60.13(c); 40 CFR 60.13(d)(1); 40 CFR 60.13(e)(2); 40 CFR 60.13(f); 40 CFR 60.13(g); 40 CFR 60.13(h)(2); 40 CFR 60.13(h)(3); 40 CFR 60.13(i)(1); 40 CFR 60.13(i)(2); 40 CFR 60.13(i)(3); 40 CFR 60.13(i)(4); 40 CFR 60.13(i)(5); 40 CFR 60.13(i)(6); 40 CFR 60.13(i)(7); 40 CFR 60.13(i)(8); 40 CFR 60.13(i)(9); 40 CFR 60.13(j)(1); 40 CFR 60.13(j)(2);

SI Id	Sequence	ID	Requirement
			40 CFR 60.14(a); 40 CFR 60.14(b); 40 CFR 60.14(c); 40 CFR 60.14(e); 40 CFR 60.14(f); 40 CFR 60.14(g); 40 CFR 60.14(h); 40 CFR 60.14(i); 40 CFR 60.14(j); 40 CFR 60.15(a); 40 CFR 60.15(b); 40 CFR 60.15(c); 40 CFR 60.15(d); 40 CFR 60.15(e); 40 CFR 60.15(f); 40 CFR 60.15(g); 40 CFR 60.17; 40 CFR 60.19(a); 40 CFR 60.19(b); 40 CFR 60.19(c); 40 CFR 60.19(d); 40 CFR 60.19(e); 40 CFR 60.19(f)(1); 40 CFR 60.19(f)(2); 40 CFR 60.19(f)(3); and 40 CFR 60.19(f)(4).
			A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If applicable sections of the standard change or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. GG, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2350, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 8	19880	1525611	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 8	19890	1525612	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 8	19900	1525613	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 8	19940	1527345	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Permit Issuance Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 9	2200	1265213	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
EQUI 9	2590	1440496	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]
EQUI 9	2600	1440497	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]
EQUI 10	2200	1265213	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
EQUI 10	2220	1265215	Cylinder Gas Audit (CGA) Results Summary: due 30 days after end of each calendar quarter in which a CGA was conducted. [Minn. R. 7017.1180, subp. 1]
EQUI 10	2460	1370550	The Permittee must conduct a cylinder gas audit: Due by the end of each three of four calendar quarters but no more than three quarters in succession. A CGA is not required during any calendar quarter in which a RATA was performed. [40 CFR pt. 60, Appendix F, 5.1.2, Minn. R. 7017.1010, subp. 1(C)]
EQUI 10	2470	1370551	The Permittee must conduct a relative accuracy test audit: Due one of each four calendar quarters. [40 CFR pt. 60, Appendix F, 5.1.1, Minn. R. 7017.1010, subp. 1(C)]
EQUI 11	2200	1265213	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
EQUI 11	2590	1440496	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]

SI Id	Sequence	ID	Requirement
EQUI 11	2600	1440497	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]
EQUI 12	2200	1265213	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
EQUI 12	2220	1265215	Cylinder Gas Audit (CGA) Results Summary: due 30 days after end of each calendar quarter in which a CGA was conducted. [Minn. R. 7017.1180, subp. 1]
EQUI 12	2460	1370550	The Permittee must conduct a cylinder gas audit: Due by the end of each three of four calendar quarters but no more than three quarters in succession. A CGA is not required during any calendar quarter in which a RATA was performed. [40 CFR pt. 60, Appendix F, 5.1.2, Minn. R. 7017.1010, subp. 1(C)]
EQUI 12	2470	1370551	The Permittee must conduct a relative accuracy test audit: Due one of each four calendar quarters. [40 CFR pt. 60, Appendix F, 5.1.1, Minn. R. 7017.1010, subp. 1(C)]
EQUI 23	1	1535499	Alternative Operating Scenario 1 (AOS 1): Engine Generator 1 (EQUI 23) operates while firing natural gas with ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
EQUI 23	2	1535500	Alternative Operating Scenario 2 (AOS 2): Engine Generator 1 (EQUI 23) operates while firing ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
EQUI 23	3	1535501	Recordkeeping of Alternative Operating Scenario: On each day of operation, the Permittee shall record the alternative operating scenario in which the engine generator is operating. If the Permittee changes the alternative operating scenario, record the date and time of the change and the new alternative operating scenario in which the engine generator is operating. [Minn. R. 7007.0800, subp. 11, Minn. R. 7007.0800, subps. 4-5]
EQUI 23	4	1544422	The Permittee must limit Operating Hours <= 241 hours per year 12-month rolling sum in burn-in operation during the 12-month period following initial startup of EQUI 23. This limit expires 366 days after initial startup of EQUI 23. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	5	1544417	The Permittee must limit Operating Hours <= 8109 hours per year 12-month rolling sum in normal operation during the 12-month period following initial startup of EQUI 23. This limit expires 366 days after initial startup of EQUI 23. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	6	1544424	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 23 operated in burn-in operation. The Permittee shall record the start time and stop time in burn-in operation. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	7	1544457	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 23 operated in normal operation. The Permittee shall record the start time and stop time in normal operation. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	8	1544431	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 23 in burn-in operation for the previous month, and 2. the total hours of EQUI 23 in burn-in operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5]
EQUI 23	9	1544477	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 23 in normal operation for the previous month, and 2. the total hours of EQUI 23 in normal operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 23. [Minn. R. 7007.0800, subps. 4-5]
EQUI 23	10	1544559	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and until 75% load is attained. 2. Shutdown begins when the fuel feed is ceased. 3. Emergency operation occurs when the unit is at less than 75% load and not in startup. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 23	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 23	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 23	3535	1525821	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 23	3540	1525297	Fuel type: Natural gas and Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	3560	1532075	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	3565	1532484	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19530	1525296	EQUI 23 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subps. IIII and JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 23. [40 CFR 63.6590(c), Minn. R. 7011.8150]
EQUI 23	19531	1525325	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]

SI Id	Sequence	ID	Requirement
EQUI 23	19532	1525330	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a); 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4204(c)(3); 40 CFR 60.4204(c)(4); 40 CFR 60.4206; 40 CFR 60.4207(d); 40 CFR 60.4211(a)(1)-(a)(3); 40 CFR 60.4211(d)(1)-(d)(3); 40 CFR 60.4213(a)-(f); 40 CFR 60.4214(a)(1)-(a)(2); 40 CFR 60.4218; 40 CFR 60.4219; 40 CFR pt. 60, subp. IIII Table 7 items (b)-(d); and 40 CFR pt. 60, subp. IIII Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 23	19533	1535393	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJJ(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]

SI Id	Sequence	ID	Requirement
EQUI 23	19534	1535394	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows: 40 CFR 60.4230(a)(6); 40 CFR 60.4233(e); 40 CFR 60.4234; 40 CFR 60.4236(b); 40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4243(e); 40 CFR 60.4244; 40 CFR 60.4245(a)(1), (a)(2), and (a)(4); 40 CFR 60.4245(c); 40 CFR 60.4245(d); 40 CFR 60.4246(a); 40 CFR 60.4246(b); 40 CFR 60.4248; 40 CFR pt. 60, subp. JJJJ Table 1; 40 CFR pt. 60, subp. JJJJ Table 2; 40 CFR pt. 60, subp. JJJJ Table 3; and 40 CFR pt. 60, subp. JJJJ Table 4. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix K. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 23	19536	1525374	The Permittee must limit emissions of Nitrogen Oxides according to the following equation in units of grams per horsepower-hour: NOx <= 6.7 * n^-0.20 or in units of grams per kilowatt-hour: NOx <= 9.0 * n^-0.20 Where: NOx = nitrogen oxide emissions, g/hp-hr or g/kW-hr n = maximum engine speed >= 130 rpm and < 2000 rpm This limit applies when operating in AOS 2. [40 CFR 60.4204(c)(3)(ii), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 23	19538	1535396	The Permittee must limit emissions of Nitrogen Oxides <= 1.0 grams per horsepower-hour (1.36 g/kW-hr) or 82 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 23	19539	1535397	The Permittee must limit emissions of Carbon Monoxide <= 2.0 grams per horsepower-hour (2.72 g/kW-hr) or 270 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 23	19540	1535398	The Permittee must limit emissions of Volatile Organic Compounds <= 0.7 grams per horsepower-hour (0.95 g/kW-hr) or 60 ppmvd at 15% O2, not including formaldehyde, when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 23	19541	1525378	The Permittee must limit emissions of Nitrogen Oxides <= 0.07 grams per horsepower-hour 24-hour rolling average (0.09 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19542	1525380	The Permittee must limit emissions of Nitrogen Oxides <= 0.39 grams per horsepower-hour 24-hour rolling average (0.53 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	19543	1525383	The Permittee must limit emissions of Nitrogen Oxides <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19544	1525384	The Permittee must limit emissions of Nitrogen Oxides <= 0.49 grams per horsepower-hour 24-hour rolling average (0.66 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19545	1525385	The Permittee must limit emissions of Nitrogen Oxides <= 1.65 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19546	1525386	The Permittee must limit emissions of Nitrogen Oxides <= 10.86 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 23	19547	1536200	The Permittee must limit emissions of Nitrogen Oxides <= 15.82 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 45.20 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19548	1536201	The Permittee must limit emissions of Nitrogen Oxides <= 2.16 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 90 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19549	1525392	The Permittee must limit emissions of Particulate Matter <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr), or reduce particulate matter emissions by 60% or more. This limit applies when operating in AOS 2 at greater than or equal to 75% load. [40 CFR 60.4204(c)(4), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19550	1525395	The Permittee must limit emissions of Particulate Matter <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19551	1525397	The Permittee must limit emissions of Particulate Matter <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19552	1536207	The Permittee must limit emissions of Particulate Matter <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19553	1536208	The Permittee must limit emissions of Particulate Matter <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19554	1525401	The Permittee must limit emissions of PM < 10 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19555	1525402	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19556	1525403	The Permittee must limit emissions of PM < 10 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19557	1525404	The Permittee must limit emissions of PM < 10 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19558	1525405	The Permittee must limit emissions of PM < 10 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	19559	1525406	The Permittee must limit emissions of PM < 10 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19560	1536251	The Permittee must limit emissions of PM < 10 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM10 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19561	1536252	The Permittee must limit emissions of PM < 10 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM10. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19562	1525411	The Permittee must limit emissions of PM < 2.5 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19563	1525412	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19564	1525413	The Permittee must limit emissions of PM < 2.5 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19565	1525414	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19566	1525415	The Permittee must limit emissions of PM < 2.5 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19567	1525416	The Permittee must limit emissions of PM < 2.5 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 23	19568	1536253	The Permittee must limit emissions of PM < 2.5 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM2.5 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19569	1536255	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM2.5. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19570	1525433	The Permittee must limit emissions of Carbon Monoxide <= 0.10 grams per horsepower-hour 24-hour rolling average (0.13 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19571	1525435	The Permittee must limit emissions of Carbon Monoxide <= 0.14 grams per horsepower-hour 24-hour rolling average (0.19 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19572	1525436	The Permittee must limit emissions of Carbon Monoxide <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19573	1525438	The Permittee must limit emissions of Carbon Monoxide <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19574	1525439	The Permittee must limit emissions of Carbon Monoxide <= 2.51 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	19575	1525440	The Permittee must limit emissions of Carbon Monoxide <= 3.78 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19576	1536203	The Permittee must limit emissions of Carbon Monoxide <= 3.71 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 10.60 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19577	1536204	The Permittee must limit emissions of Carbon Monoxide <= 0.50 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 21 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19578	1525443	The Permittee must limit emissions of Volatile Organic Compounds <= 0.13 grams per horsepower-hour 24-hour rolling average (as methane, 0.17 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19579	1525446	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 grams per horsepower-hour 24-hour rolling average (as methane, 0.21 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19580	1525447	The Permittee must limit emissions of Volatile Organic Compounds <= 0.22 grams per horsepower-hour 24-hour rolling average (as methane, 0.30 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19581	1525452	The Permittee must limit emissions of Volatile Organic Compounds <= 0.17 grams per horsepower-hour 24-hour rolling average (as methane, 0.23 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19582	1525454	The Permittee must limit emissions of Volatile Organic Compounds <= 3.26 pounds per hour 3-hour average (as methane) when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19583	1525455	The Permittee must limit emissions of Volatile Organic Compounds <= 4.33 pounds per hour 3-hour average (as methane) when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19584	1536205	The Permittee must limit emissions of Volatile Organic Compounds <= 1.16 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 3.32 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 23 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19585	1536206	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 6.44 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19586	1525460	The Permittee must limit the Sulfur Content of Fuel <= 1000 parts per million per gallon of diesel. This limit applies when operating in AOS 2. [40 CFR 60.4207(d), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 23	19587	1525463	The Permittee must limit emissions of Carbon Dioxide <= 377 grams per horsepower-hour 24-hour rolling average (512 g/kW-hr) when operating in AOS 1. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19588	1525464	The Permittee must limit emissions of Carbon Dioxide <= 494 grams per horsepower-hour 24-hour rolling average (672 g/kW-hr) when operating in AOS 2. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19589	1525465	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 72,583 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	19590	1525685	The Permittee must operate EQUI 23 using good combustion practices during startup, shutdown and emergency operation. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the engine temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits, whichever occurs first. Shutdown begins when the Permittee initiates the shutdown of the engine and when fuel is no longer being introduced into the engine. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19591	1528192	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 23. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = (((MNG * 110) + ((MNG * 0.0022) * 25) + ((MNG * 0.00022) * 298)) + ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298))) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; MD = mmBtu of diesel fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0022 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 23 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19592	1536209	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 700 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19593	1536210	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 23 while operating in emergency mode. Sum the number of hours EQUI 23 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19594	1536884	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19595	1536885	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19596	1536886	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	19880	1525568	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19890	1525569	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 23	19900	1525570	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(items c, d), Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	19910	1525679	Carbon Monoxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 10, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 23	19920	1525571	Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 60.4242(b)(2)(ii), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(item b), Minn. R. 7011.2305, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 23	19940	1525572	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 60.4245(d), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	1	1535512	Alternative Operating Scenario 1 (AOS 1): Engine Generator 2 (EQUI 24) operates while firing natural gas with ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
EQUI 24	2	1535513	Alternative Operating Scenario 2 (AOS 2): Engine Generator 2 (EQUI 24) operates while firing ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
EQUI 24	3	1535514	Recordkeeping of Alternative Operating Scenario: On each day of operation, the Permittee shall record the alternative operating scenario in which the engine generator is operating. If the Permittee changes the alternative operating scenario, record the date and time of the change and the new alternative operating scenario in which the engine generator is operating. [Minn. R. 7007.0800, subp. 11, Minn. R. 7007.0800, subps. 4-5]
EQUI 24	4	1544488	The Permittee must limit Operating Hours <= 241 hours per year 12-month rolling sum in burn-in operation during the 12-month period following initial startup of EQUI 24. This limit expires 366 days after initial startup of EQUI 24. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	5	1544489	The Permittee must limit Operating Hours <= 8109 hours per year 12-month rolling sum in normal operation during the 12-month period following initial startup of EQUI 24. This limit expires 366 days after initial startup of EQUI 24. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	6	1544490	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 24 operated in burn-in operation. The Permittee shall record the start time and stop time in burn-in operation. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	7	1544491	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 24 operated in normal operation. The Permittee shall record the start time and stop time in normal operation. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	8	1544492	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 24 in burn-in operation for the previous month, and 2. the total hours of EQUI 24 in burn-in operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5]
EQUI 24	9	1544493	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 24 in normal operation for the previous month, and 2. the total hours of EQUI 24 in normal operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 24. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
EQUI 24	10	1544565	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and until 75% load is attained. 2. Shutdown begins when the fuel feed is ceased. 3. Emergency operation occurs when the unit is at less than 75% load and not in startup. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 24	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 24	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 24	3535	1529687	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 24	3540	1529689	Fuel type: Natural gas and Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	3560	1532076	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	3565	1532486	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19530	1529690	EQUI 24 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subps. IIII and JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 24. [40 CFR 63.6590(c), Minn. R. 7011.8150]
EQUI 24	19531	1529705	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]

SI Id	Sequence	ID	Requirement
EQUI 24	19532	1529706	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a); 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4204(c)(3); 40 CFR 60.4204(c)(4); 40 CFR 60.4206; 40 CFR 60.4207(d); 40 CFR 60.4211(a)(1)-(a)(3); 40 CFR 60.4211(d)(1)-(d)(3); 40 CFR 60.4213(a)-(f); 40 CFR 60.4214(a)(1)-(a)(2); 40 CFR 60.4218; 40 CFR 60.4219; 40 CFR pt. 60, subp. IIII Table 7 items (b)-(d); and 40 CFR pt. 60, subp. IIII Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 24	19533	1535401	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJJ(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]

SI Id	Sequence	ID	Requirement
EQUI 24	19534	1535402	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows: 40 CFR 60.4230(a)(6); 40 CFR 60.4233(e); 40 CFR 60.4234; 40 CFR 60.4236(b); 40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4243(e); 40 CFR 60.4244; 40 CFR 60.4245(a)(1), (a)(2), and (a)(4); 40 CFR 60.4245(c); 40 CFR 60.4245(d); 40 CFR 60.4246(a); 40 CFR 60.4246(b); 40 CFR 60.4248; 40 CFR pt. 60, subp. JJJJ Table 1; 40 CFR pt. 60, subp. JJJJ Table 2; 40 CFR pt. 60, subp. JJJJ Table 3; and 40 CFR pt. 60, subp. JJJJ Table 4. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix K. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 24	19536	1529708	The Permittee must limit emissions of Nitrogen Oxides according to the following equation in units of grams per horsepower-hour: NOx <= 6.7 * n^-0.20 or in units of grams per kilowatt-hour: NOx <= 9.0 * n^-0.20 Where: NOx = nitrogen oxide emissions, g/hp-hr or g/kW-hr n = maximum engine speed >= 130 rpm and < 2000 rpm This limit applies when operating in AOS 2. [40 CFR 60.4204(c)(3)(ii), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 24	19538	1535406	The Permittee must limit emissions of Nitrogen Oxides <= 1.0 grams per horsepower-hour (1.36 g/kW-hr) or 82 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 24	19539	1535407	The Permittee must limit emissions of Carbon Monoxide <= 2.0 grams per horsepower-hour (2.72 g/kW-hr) or 270 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 24	19540	1535408	The Permittee must limit emissions of Volatile Organic Compounds <= 0.7 grams per horsepower-hour (0.95 g/kW-hr) or 60 ppmvd at 15% O2, not including formaldehyde, when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 24	19541	1529710	The Permittee must limit emissions of Nitrogen Oxides <= 0.07 grams per horsepower-hour 24-hour rolling average (0.09 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19542	1529711	The Permittee must limit emissions of Nitrogen Oxides <= 0.39 grams per horsepower-hour 24-hour rolling average (0.53 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 24	19543	1529712	The Permittee must limit emissions of Nitrogen Oxides <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19544	1529713	The Permittee must limit emissions of Nitrogen Oxides <= 0.49 grams per horsepower-hour 24-hour rolling average (0.66 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19545	1529714	The Permittee must limit emissions of Nitrogen Oxides <= 1.65 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19546	1529715	The Permittee must limit emissions of Nitrogen Oxides <= 10.86 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 24	19547	1536221	The Permittee must limit emissions of Nitrogen Oxides <= 15.82 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 45.20 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19548	1536222	The Permittee must limit emissions of Nitrogen Oxides <= 2.16 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 90 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19549	1529737	The Permittee must limit emissions of Particulate Matter <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr), or reduce particulate matter emissions by 60% or more. This limit applies when operating in AOS 2 at greater than or equal to 75% load. [40 CFR 60.4204(c)(4), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19550	1529738	The Permittee must limit emissions of Particulate Matter <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19551	1529739	The Permittee must limit emissions of Particulate Matter <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19552	1536227	The Permittee must limit emissions of Particulate Matter <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19553	1536228	The Permittee must limit emissions of Particulate Matter <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19554	1529741	The Permittee must limit emissions of PM < 10 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19555	1529742	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19556	1529743	The Permittee must limit emissions of PM < 10 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19557	1529744	The Permittee must limit emissions of PM < 10 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19558	1529745	The Permittee must limit emissions of PM < 10 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 24	19559	1529746	The Permittee must limit emissions of PM < 10 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19560	1536260	The Permittee must limit emissions of PM < 10 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM10 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19561	1536261	The Permittee must limit emissions of PM < 10 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM10. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19562	1529748	The Permittee must limit emissions of PM < 2.5 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19563	1529749	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19564	1529750	The Permittee must limit emissions of PM < 2.5 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19565	1529751	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19566	1529752	The Permittee must limit emissions of PM < 2.5 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19567	1529753	The Permittee must limit emissions of PM < 2.5 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 24	19568	1536262	The Permittee must limit emissions of PM < 2.5 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM2.5 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19569	1536263	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM2.5. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19570	1529755	The Permittee must limit emissions of Carbon Monoxide <= 0.10 grams per horsepower-hour 24-hour rolling average (0.13 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19571	1529776	The Permittee must limit emissions of Carbon Monoxide <= 0.14 grams per horsepower-hour 24-hour rolling average (0.19 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19572	1529777	The Permittee must limit emissions of Carbon Monoxide <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19573	1529778	The Permittee must limit emissions of Carbon Monoxide <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19574	1529779	The Permittee must limit emissions of Carbon Monoxide <= 2.51 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 24	19575	1529780	The Permittee must limit emissions of Carbon Monoxide <= 3.78 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19576	1536223	The Permittee must limit emissions of Carbon Monoxide <= 3.71 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 10.60 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19577	1536224	The Permittee must limit emissions of Carbon Monoxide <= 0.50 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 21 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19578	1529782	The Permittee must limit emissions of Volatile Organic Compounds <= 0.13 grams per horsepower-hour 24-hour rolling average (as methane, 0.17 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19579	1529783	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 grams per horsepower-hour 24-hour rolling average (as methane, 0.21 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19580	1529784	The Permittee must limit emissions of Volatile Organic Compounds <= 0.22 grams per horsepower-hour 24-hour rolling average (as methane, 0.30 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19581	1529785	The Permittee must limit emissions of Volatile Organic Compounds <= 0.17 grams per horsepower-hour 24-hour rolling average (as methane, 0.23 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19582	1529786	The Permittee must limit emissions of Volatile Organic Compounds <= 3.26 pounds per hour 3-hour average (as methane) when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19583	1529787	The Permittee must limit emissions of Volatile Organic Compounds <= 4.33 pounds per hour 3-hour average (as methane) when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19584	1536225	The Permittee must limit emissions of Volatile Organic Compounds <= 1.16 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 3.32 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 24 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19585	1536226	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 6.44 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19586	1529789	The Permittee must limit the Sulfur Content of Fuel <= 1000 parts per million per gallon of diesel. This limit applies when operating in AOS 2. [40 CFR 60.4207(d), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 24	19587	1529790	The Permittee must limit emissions of Carbon Dioxide <= 377 grams per horsepower-hour 24-hour rolling average (512 g/kW-hr) when operating in AOS 1. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19588	1529791	The Permittee must limit emissions of Carbon Dioxide <= 494 grams per horsepower-hour 24-hour rolling average (672 g/kW-hr) when operating in AOS 2. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19589	1529792	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 72,583 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 24	19590	1529793	The Permittee must operate EQUI 24 using good combustion practices during startup, shutdown and emergency operation. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the engine temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits, whichever occurs first. Shutdown begins when the Permittee initiates the shutdown of the engine and when fuel is no longer being introduced into the engine. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19591	1529794	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 24. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = (((MNG * 110) + ((MNG * 0.0022) * 25) + ((MNG * 0.00022) * 298)) + ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298))) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; MD = mmBtu of diesel fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0022 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 24 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19592	1536229	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 700 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19593	1536230	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 24 while operating in emergency mode. Sum the number of hours EQUI 24 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19594	1536881	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19595	1536882	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19596	1536883	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 24	19880	1529795	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19890	1529801	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 24	19900	1529802	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(items c, d), Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 24	19910	1529803	Carbon Monoxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 10, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 24	19920	1529804	Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(item b), Minn. R. 7011.2305, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 24	19940	1529805	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 60.4245(d), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	1	1535509	Alternative Operating Scenario 1 (AOS 1): Engine Generator 3 (EQUI 25) operates while firing natural gas with ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
EQUI 25	2	1535510	Alternative Operating Scenario 2 (AOS 2): Engine Generator 3 (EQUI 25) operates while firing ultra-low sulfur diesel. [Minn. R. 7007.0800, subp. 11]
EQUI 25	3	1535511	Recordkeeping of Alternative Operating Scenario: On each day of operation, the Permittee shall record the alternative operating scenario in which the engine generator is operating. If the Permittee changes the alternative operating scenario, record the date and time of the change and the new alternative operating scenario in which the engine generator is operating. [Minn. R. 7007.0800, subp. 11, Minn. R. 7007.0800, subps. 4-5]
EQUI 25	4	1544482	The Permittee must limit Operating Hours <= 241 hours per year 12-month rolling sum in burn-in operation during the 12-month period following initial startup of EQUI 25. This limit expires 366 days after initial startup of EQUI 25. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	5	1544483	The Permittee must limit Operating Hours <= 8109 hours per year 12-month rolling sum in normal operation during the 12-month period following initial startup of EQUI 25. This limit expires 366 days after initial startup of EQUI 25. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	6	1544484	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 25 operated in burn-in operation. The Permittee shall record the start time and stop time in burn-in operation. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	7	1544485	Daily Recordkeeping of Operation Mode: On each day of operation, the Permittee shall calculate and record the total number of hours EQUI 25 operated in normal operation. The Permittee shall record the start time and stop time in normal operation. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	8	1544486	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 25 in burn-in operation for the previous month, and 2. the total hours of EQUI 25 in burn-in operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5]
EQUI 25	9	1544487	Monthly Recordkeeping of Operation Mode: By the 15th day of each month, the Permittee shall calculate and record: 1. the total hours of EQUI 25 in normal operation for the previous month, and 2. the total hours of EQUI 25 in normal operation for the previous 12 months, 12-month rolling sum. This requirement expires 366 days after initial startup of EQUI 25. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
EQUI 25	10	1544564	Startup/Shutdown and Emergency Operation Modes: 1. Startup commences upon initial firing and until 75% load is attained. 2. Shutdown begins when the fuel feed is ceased. 3. Emergency operation occurs when the unit is at less than 75% load and not in startup. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 25	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 25	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 25	3535	1529691	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 25	3540	1529692	Fuel type: Natural gas and Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	3560	1532077	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	3565	1532488	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19530	1529693	EQUI 25 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subps. IIII and JJJJ. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 25. [40 CFR 63.6590(c), Minn. R. 7011.8150]
EQUI 25	19531	1529694	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.13; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]

SI Id	Sequence	ID	Requirement
EQUI 25	19532	1529695	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a); 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4204(c)(3); 40 CFR 60.4204(c)(4); 40 CFR 60.4206; 40 CFR 60.4207(d); 40 CFR 60.4211(a)(1)-(a)(3); 40 CFR 60.4211(d)(1)-(d)(3); 40 CFR 60.4213(a)-(f); 40 CFR 60.4214(a)(1)-(a)(2); 40 CFR 60.4218; 40 CFR 60.4219; 40 CFR pt. 60, subp. IIII Table 7 items (b)-(d); and 40 CFR pt. 60, subp. IIII Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 25	19533	1535399	The Permittee must comply with all the applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.11; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4246(a), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. JJJJ(Table 3), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]

SI Id	Sequence	ID	Requirement
EQUI 25	19534	1535400	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. JJJJ as follows: 40 CFR 60.4230(a)(6); 40 CFR 60.4233(e); 40 CFR 60.4234; 40 CFR 60.4236(b); 40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4243(e); 40 CFR 60.4244; 40 CFR 60.4245(a)(1), (a)(2), and (a)(4); 40 CFR 60.4245(c); 40 CFR 60.4245(d); 40 CFR 60.4246(a); 40 CFR 60.4246(b); 40 CFR 60.4248; 40 CFR pt. 60, subp. JJJJ Table 1; 40 CFR pt. 60, subp. JJJJ Table 2; 40 CFR pt. 60, subp. JJJJ Table 3; and 40 CFR pt. 60, subp. JJJJ Table 4. A copy of 40 CFR pt. 60, subp. JJJJ is included in Appendix K. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 25	19536	1529697	The Permittee must limit emissions of Nitrogen Oxides according to the following equation in units of grams per horsepower-hour: NOx <= 6.7 * n^-0.20 or in units of grams per kilowatt-hour: NOx <= 9.0 * n^-0.20 Where: NOx = nitrogen oxide emissions, g/hp-hr or g/kW-hr n = maximum engine speed >= 130 rpm and < 2000 rpm This limit applies when operating in AOS 2. [40 CFR 60.4204(c)(3)(ii), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 25	19538	1535403	The Permittee must limit emissions of Nitrogen Oxides <= 1.0 grams per horsepower-hour (1.36 g/kW-hr) or 82 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 25	19539	1535404	The Permittee must limit emissions of Carbon Monoxide <= 2.0 grams per horsepower-hour (2.72 g/kW-hr) or 270 ppmvd at 15% O2 when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 25	19540	1535405	The Permittee must limit emissions of Volatile Organic Compounds <= 0.7 grams per horsepower-hour (0.95 g/kW-hr) or 60 ppmvd at 15% O2, not including formaldehyde, when operating in AOS 1. [40 CFR 60.4233(e), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. JJJJ(Table 1), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2310, Minn. R. 7011.8150]
EQUI 25	19541	1529699	The Permittee must limit emissions of Nitrogen Oxides <= 0.07 grams per horsepower-hour 24-hour rolling average (0.09 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 25	19542	1529700	The Permittee must limit emissions of Nitrogen Oxides <= 0.39 grams per horsepower-hour 24-hour rolling average (0.53 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19543	1529701	The Permittee must limit emissions of Nitrogen Oxides <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19544	1529702	The Permittee must limit emissions of Nitrogen Oxides <= 0.49 grams per horsepower-hour 24-hour rolling average (0.66 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19545	1529703	The Permittee must limit emissions of Nitrogen Oxides <= 1.65 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19546	1529704	The Permittee must limit emissions of Nitrogen Oxides <= 10.86 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 25	19547	1536211	The Permittee must limit emissions of Nitrogen Oxides <= 15.82 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. NOx is limited to 45.20 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19548	1536212	The Permittee must limit emissions of Nitrogen Oxides <= 2.16 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 90 lb/hr NOx. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19549	1529717	The Permittee must limit emissions of Particulate Matter <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr), or reduce particulate matter emissions by 60% or more. This limit applies when operating in AOS 2 at greater than or equal to 75% load. [40 CFR 60.4204(c)(4), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19550	1529718	The Permittee must limit emissions of Particulate Matter <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19551	1529719	The Permittee must limit emissions of Particulate Matter <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19552	1536217	The Permittee must limit emissions of Particulate Matter <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19553	1536218	The Permittee must limit emissions of Particulate Matter <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19554	1529721	The Permittee must limit emissions of PM < 10 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19555	1529722	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19556	1529723	The Permittee must limit emissions of PM < 10 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19557	1529724	The Permittee must limit emissions of PM < 10 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 25	19558	1529725	The Permittee must limit emissions of PM < 10 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19559	1529726	The Permittee must limit emissions of PM < 10 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19560	1536256	The Permittee must limit emissions of PM < 10 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM10 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19561	1536257	The Permittee must limit emissions of PM < 10 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM10. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19562	1529728	The Permittee must limit emissions of PM < 2.5 micron <= 0.07 grams per horsepower-hour 24-hour rolling average (0.10 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19563	1529729	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19564	1529730	The Permittee must limit emissions of PM < 2.5 micron <= 0.12 grams per horsepower-hour 24-hour rolling average (0.16 g/kW-hr) when operating in AOS 1 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19565	1529731	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 grams per horsepower-hour 24-hour rolling average (0.32 g/kW-hr) when operating in AOS 2 and less than 75% load. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19566	1529732	The Permittee must limit emissions of PM < 2.5 micron <= 2.01 pounds per hour 3-hour average when operating in AOS 1 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19567	1529733	The Permittee must limit emissions of PM < 2.5 micron <= 4.76 pounds per hour 3-hour average when operating in AOS 2 in normal operation. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 25	19568	1536258	The Permittee must limit emissions of PM < 2.5 micron <= 1.77 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. PM2.5 is limited to 5.05 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19569	1536259	The Permittee must limit emissions of PM < 2.5 micron <= 0.24 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 10.0 lb/hr PM2.5. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19570	1529735	The Permittee must limit emissions of Carbon Monoxide <= 0.10 grams per horsepower-hour 24-hour rolling average (0.13 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19571	1529756	The Permittee must limit emissions of Carbon Monoxide <= 0.14 grams per horsepower-hour 24-hour rolling average (0.19 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19572	1529757	The Permittee must limit emissions of Carbon Monoxide <= 0.11 grams per horsepower-hour 24-hour rolling average (0.15 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19573	1529758	The Permittee must limit emissions of Carbon Monoxide <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 25	19574	1529759	The Permittee must limit emissions of Carbon Monoxide <= 2.51 pounds per hour 3-hour average when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19575	1529760	The Permittee must limit emissions of Carbon Monoxide <= 3.78 pounds per hour 3-hour average when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19576	1536213	The Permittee must limit emissions of Carbon Monoxide <= 3.71 tons per year 12-month rolling sum during startup and shutdown (SUSD) events. CO is limited to 10.60 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19577	1536214	The Permittee must limit emissions of Carbon Monoxide <= 0.50 tons per year 12-month rolling sum during emergency operation. Emergency operation is limited to 21 lb/hr CO. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19578	1529762	The Permittee must limit emissions of Volatile Organic Compounds <= 0.13 grams per horsepower-hour 24-hour rolling average (as methane, 0.17 g/kW-hr) when operating in AOS 1 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19579	1529763	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 grams per horsepower-hour 24-hour rolling average (as methane, 0.21 g/kW-hr) when operating in AOS 2 and greater than or equal to 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19580	1529764	The Permittee must limit emissions of Volatile Organic Compounds <= 0.22 grams per horsepower-hour 24-hour rolling average (as methane, 0.30 g/kW-hr) when operating in AOS 1 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19581	1529765	The Permittee must limit emissions of Volatile Organic Compounds <= 0.17 grams per horsepower-hour 24-hour rolling average (as methane, 0.23 g/kW-hr) when operating in AOS 2 and less than 75% load. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19582	1529766	The Permittee must limit emissions of Volatile Organic Compounds <= 3.26 pounds per hour 3-hour average (as methane) when operating in AOS 1 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19583	1529767	The Permittee must limit emissions of Volatile Organic Compounds <= 4.33 pounds per hour 3-hour average (as methane) when operating in AOS 2 in normal operation. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19584	1536215	The Permittee must limit emissions of Volatile Organic Compounds <= 1.16 tons per year 12-month rolling sum (as methane) during startup and shutdown (SUSD) events. VOC is limited to 3.32 lbs per SUSD event. Startup shall last no greater than 30 minutes per event. Shutdown shall last no greater than 1 minute per event. EQUI 25 shall conduct no greater than 2 SUSD events per day using diesel. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19585	1536216	The Permittee must limit emissions of Volatile Organic Compounds <= 0.15 tons per year 12-month rolling sum (as methane) during emergency operation. Emergency operation is limited to 6.44 lb/hr VOC. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19586	1529769	The Permittee must limit the Sulfur Content of Fuel <= 1000 parts per million per gallon of diesel. This limit applies when operating in AOS 2. [40 CFR 60.4207(d), 40 CFR 63.6590(c), Minn. R. 7007.0800, subp. 11, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 25	19587	1529770	The Permittee must limit emissions of Carbon Dioxide <= 377 grams per horsepower-hour 24-hour rolling average (512 g/kW-hr) when operating in AOS 1. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 25	19588	1529771	The Permittee must limit emissions of Carbon Dioxide <= 494 grams per horsepower-hour 24-hour rolling average (672 g/kW-hr) when operating in AOS 2. [Minn. R. 7007.0800, subp. 11, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19589	1529772	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 72,583 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19590	1529773	The Permittee must operate EQUI 25 using good combustion practices during startup, shutdown and emergency operation. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the engine temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits, whichever occurs first. Shutdown begins when the Permittee initiates the shutdown of the engine and when fuel is no longer being introduced into the engine. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19591	1529774	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 25. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = (((MNG * 110) + ((MNG * 0.0022) * 25) + ((MNG * 0.00022) * 298)) + ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298))) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MNG = mmBtu of natural gas fuel burned in the previous month; MD = mmBtu of diesel fuel burned in the previous month; 110 = CO2 emission factor for natural gas in lb/mmBtu; 0.0022 = CH4 emission factor for natural gas in lb/mmBtu; 0.00022 = N2O emission factor for natural gas in lb/mmBtu; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 25 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19592	1536219	Recordkeeping for Startup/Shutdown Events: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of each startup and shutdown event. Sum the startup/shutdown events for the previous 12 months. The 12-month rolling sum shall not exceed 700 events. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19593	1536220	Recordkeeping for Emergency Operation: By the 15th of the month for the previous month, the Permittee must record the date, time and duration of EQUI 25 while operating in emergency mode. Sum the number of hours EQUI 25 operated in emergency mode for the previous 12 months. The 12-month rolling sum shall not exceed 48 hours. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19594	1536878	The Permittee shall utilize proper piping design conforming to ANSI, API, ASME, or other standards, and best management practices to prevent, detect, and repair leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19595	1536879	The Permittee shall conduct audio/visual/olfactory (AVO) inspections each calendar quarter for natural gas piping components to detect leaks of natural gas. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19596	1536880	The Permittee shall keep records of the quarterly AVO leak inspections on natural gas piping components. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 25	19880	1529775	PM < 10 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19890	1529796	PM < 2.5 micron: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 201A and 202, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 25	19900	1529797	Particulate Matter: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Method 5, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(items c, d), Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 25	19910	1529798	Carbon Monoxide: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 10, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 25	19920	1529799	Nitrogen Oxides: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 12 months thereafter to measure emissions. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 7E, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4211(d)(3), 40 CFR 60.4243(b)(2)(ii), 40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII(Table 7)(item b), Minn. R. 7011.2305, Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 25	19940	1529800	Volatile Organic Compounds: The Permittee shall conduct an initial performance test due 180 calendar days after Initial Startup Date and at a minimum every 60 months thereafter to measure emissions. The Commissioner will set the subsequent test frequency as stated in a Notice of Compliance (NOC) or Notice of Verification (NOV) letter with review of the initial performance test. Subsequent tests shall be completed no less than every 60-months by the due date (month and day) based on the initial test date or more frequently as stated in the NOC/NOV letter. If the Commissioner sets a test frequency at less than every 60 months, the Permittee must apply for an administrative amendment to incorporate the prescribed test frequency into the permit. A major amendment is required to reduce the test frequency once set in the permit. The performance test shall be conducted at worst-case conditions defined at Minn. R. 7017.2005, subp. 8 or at the operating conditions described at Minn. R. 7017.2025, subp. 2, using EPA Reference Methods 25A, or other method approved by MPCA in the performance test plan approval. Testing conducted during the 60 days prior to a performance test due date will not reset the due date for future testing. Testing conducted more than 60 days prior to the specified due date satisfies this test due date requirement but will reset future performance test due dates based on the most recent performance test date. [40 CFR 60.4243(b)(2)(ii), 40 CFR 60.4245(d), 40 CFR 63.6590(c), Minn. R. 7011.2310, Minn. R. 7011.8150, Minn. R. 7017.2020, subp. 1, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 26	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 26	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 26	3535	1528454	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 26	3540	1525141	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	3550	1482573	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
EQUI 26	3560	1532078	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	3565	1532491	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	4550	1487329	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
EQUI 26	4560	1243495	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
EQUI 26	4580	1124563	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]

SI Id	Sequence	ID	Requirement
EQUI 26	4590	1487330	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]
EQUI 26	4600	1525062	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 26	19530	1525059	EQUI 26 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 26. [40 CFR 63.6590(c), Minn. R. 7011.8150]

SI Id	Sequence	ID	Requirement
EQUI 26	28030	1525061	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 26	28040	1525063	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28041	1525134	The Permittee must limit emissions of NMHC+NOx <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28050	1525064	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28051	1525105	The Permittee must limit emissions of Particulate Matter <= 0.35 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28052	1525106	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28053	1525108	The Permittee must limit emissions of PM < 10 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28054	1525109	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28055	1525110	The Permittee must limit emissions of PM < 2.5 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28060	1525065	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28061	1525135	The Permittee must limit emissions of Carbon Monoxide <= 6.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28062	1527223	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28063	1527224	The Permittee must limit emissions of Volatile Organic Compounds <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28064	1525136	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 314 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28070	1525066	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 26	28080	1525068	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28090	1525069	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28170	1525070	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 26	28171	1528202	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 26. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 26 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 26	28172	1531867	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 26	28173	1531868	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 27	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

SI Id	Sequence	ID	Requirement
EQUI 27	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 27	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 27	3535	1528455	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 27	3540	1525142	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	3550	1482573	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
EQUI 27	3560	1532079	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	3565	1532494	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	4550	1487329	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
EQUI 27	4560	1243495	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
EQUI 27	4580	1124563	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
EQUI 27	4590	1487330	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]

SI Id	Sequence	ID	Requirement
EQUI 27	4600	1525155	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 27	19530	1525154	EQUI 27 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 27. [40 CFR 63.6590(c), Minn. R. 7011.8150]
EQUI 27	28030	1525156	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 27	28040	1525143	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 27	28041	1525159	The Permittee must limit emissions of NMHC+NOx <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28050	1525144	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28051	1525158	The Permittee must limit emissions of Particulate Matter <= 0.35 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28052	1525161	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28053	1525162	The Permittee must limit emissions of PM < 10 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28054	1525163	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28055	1525164	The Permittee must limit emissions of PM < 2.5 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28060	1525145	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28061	1525165	The Permittee must limit emissions of Carbon Monoxide <= 6.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28062	1527233	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28063	1527234	The Permittee must limit emissions of Volatile Organic Compounds <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28064	1525166	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 314 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28070	1525146	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28080	1525147	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28090	1525148	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 27	28170	1525149	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 27	28171	1528204	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 27. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 27 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 27	28172	1531873	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 27	28173	1531874	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 28	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 28	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 28	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 28	3535	1528457	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 28	3540	1525168	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	3550	1482573	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
EQUI 28	3560	1532081	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	3565	1532498	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	4550	1487329	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
EQUI 28	4560	1243495	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
EQUI 28	4580	1124563	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]

SI Id	Sequence	ID	Requirement
EQUI 28	4590	1487330	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]
EQUI 28	4600	1525177	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 28	19530	1525169	EQUI 28 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 28. [40 CFR 63.6590(c), Minn. R. 7011.8150]

SI Id	Sequence	ID	Requirement
EQUI 28	28030	1525178	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 28	28040	1525179	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28041	1525187	The Permittee must limit emissions of NMHC+NOx <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28050	1525180	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28051	1525188	The Permittee must limit emissions of Particulate Matter <= 0.35 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28052	1525189	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28053	1525190	The Permittee must limit emissions of PM < 10 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28054	1525191	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28055	1525192	The Permittee must limit emissions of PM < 2.5 micron <= 0.39 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28060	1525181	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28061	1525193	The Permittee must limit emissions of Carbon Monoxide <= 6.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28062	1527231	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28063	1527232	The Permittee must limit emissions of Volatile Organic Compounds <= 11.03 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28064	1525194	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 314 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28070	1525182	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 28	28080	1525183	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28090	1525184	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28170	1525185	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 28	28171	1528205	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 28. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 28 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 28	28172	1531871	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 28	28173	1531872	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 29	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

SI Id	Sequence	ID	Requirement
EQUI 29	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 29	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 29	3535	1528463	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 29	3540	1525195	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	3550	1482573	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
EQUI 29	3560	1532083	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	3565	1532499	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	4550	1487329	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
EQUI 29	4560	1243495	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
EQUI 29	4580	1124563	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
EQUI 29	4590	1487330	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]

SI Id	Sequence	ID	Requirement
EQUI 29	4600	1525198	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 29	19530	1525196	EQUI 29 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 29. [40 CFR 63.6590(c), Minn. R. 7011.8150]
EQUI 29	28030	1525199	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 29	28040	1525200	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 29	28041	1525207	The Permittee must limit emissions of NMHC+NOx <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28050	1525201	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28051	1525208	The Permittee must limit emissions of Particulate Matter <= 0.25 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28052	1525209	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28053	1525210	The Permittee must limit emissions of PM < 10 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28054	1525211	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28055	1525212	The Permittee must limit emissions of PM < 2.5 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28060	1525202	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28061	1525213	The Permittee must limit emissions of Carbon Monoxide <= 4.44 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28062	1527229	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28063	1527230	The Permittee must limit emissions of Volatile Organic Compounds <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28064	1525214	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 231 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28070	1525203	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28080	1525204	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28090	1525205	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 29	28170	1525206	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 29	28171	1528206	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 29. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 29 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 29	28172	1531869	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 29	28173	1531870	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
EQUI 30	2200	1265213	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
EQUI 30	2590	1440496	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]
EQUI 30	2600	1440497	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]
EQUI 31	2200	1265213	Relative Accuracy Test Audit (RATA) Results Summary: due 30 days after end of each calendar quarter in which a RATA was conducted. [Minn. R. 7017.1180, subp. 3]
EQUI 31	2590	1440496	The Permittee shall conduct linearity and leak check: Due by the end of each QA operating quarter (calendar quarter in which there are at least 168 unit operating hours) in accordance with procedures in 40 CFR pt. 75, Appendix B, Sections 2.2.1 and 2.2.2, and Appendix A, Section 6.2. Linearity checks are required for all emissions monitors and leak checks are required for all flow monitors. If the monitored emission unit is not in operation on the linearity test due date, the Permittee has a grace period of 168 operating hours to perform the linearity test. [40 CFR pt. 75, Appendix B, 2.2]
EQUI 31	2600	1440497	The Permittee shall conduct CEMS relative accuracy test audit (RATA): Due once every two successive QA operating quarters (calendar quarter in which there are at least 168 unit operating hours) in accordance with 40 CFR pt. 75, Appendix B, on all CEMS required by the Acid Rain Program. If the monitored emission unit is not in operation on the RATA due date, the Permittee has a grace period of 720 operating hours to perform the RATA. Relative accuracy test audits may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the conditions listed in 40 CFR pt. 75, Appendix B, Sections 2.3.1.2(a) through 2.3.1.2(i) are met. [40 CFR pt. 75, Appendix B, 2.3]

SI Id	Sequence	ID	Requirement
EQUI 32	1	1537565	EQUI 32 must be constructed and operated with good tank design, including: 1. Fixed roof. 2. PRV (conservation vent). 3. Submerged fill pipe. 4. Light tank color. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 33	1	1537567	EQUI 33 must be constructed and operated with good tank design, including: 1. Fixed roof. 2. PRV (conservation vent). 3. Submerged fill pipe. 4. Light tank color. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 43	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
EQUI 43	3520	1030831	Opacity <= 20 percent opacity once operating temperatures have been attained. [Minn. R. 7011.2300, subp. 1]
EQUI 43	3535	1545767	Sulfur Dioxide <= 0.0015 pounds per million Btu heat input. The potential to emit from the unit is 0.0015 lb/MMBtu due to equipment design and allowable fuels. [Minn. R. 7011.2300, subp. 2(B)]
EQUI 43	3540	1545768	Fuel type: Diesel only, by design. [Minn. R. 7005.0100, subp. 35a, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	3550	1482573	Hours of Operation: The Permittee shall maintain documentation on site that the unit is an emergency generator by design that qualifies under the U.S. EPA memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995, that allows calculation of potential emissions based on 500 operating hours per year. [Minn. R. 7007.0800, subps. 4-5]
EQUI 43	3560	1545769	The Permittee shall keep records of fuel type and usage on a monthly basis. [Minn. R. 7007.0800, subp. 5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	3565	1545770	Fuel Supplier Certification: The Permittee shall obtain and maintain a fuel supplier certification for each shipment of diesel fuel oil, certifying that the sulfur content does not exceed 0.0015 percent by weight. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	4550	1487329	The Permittee shall submit a notification of date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(1), Minn. R. 7019.0100, subp. 1]
EQUI 43	4560	1243495	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. The notification shall be submitted electronically on Form CS-02. [40 CFR 60.7(a)(3), Minn. R. 7019.0100, subp. 1]
EQUI 43	4580	1124563	The Permittee shall submit a notification of anticipated date for conducting opacity observations: Due 30 calendar days before Opacity Observation Date. [40 CFR 60.7(a)(6), Minn. R. 7019.0100, subp. 1]
EQUI 43	4590	1487330	The Permittee shall submit notification of the date construction of replacement began: Due 60 calendar days before Date of Construction or Replacement (or as soon as practicable). Submit the information specified in 40 CFR 60.15(d)(1) through (7). The notification shall be submitted electronically on Form CS-02. [40 CFR 60.15(d), Minn. R. 7011.0050]

SI Id	Sequence	ID	Requirement
EQUI 43	4600	1545771	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. A as follows: 40 CFR 60.1; 40 CFR 60.2; 40 CFR 60.3; 40 CFR 60.4; 40 CFR 60.5; 40 CFR 60.6; 40 CFR 60.7; 40 CFR 60.8; 40 CFR 60.9; 40 CFR 60.10; 40 CFR 60.12; 40 CFR 60.14; 40 CFR 60.15; 40 CFR 60.16; 40 CFR 60.17; and 40 CFR 60.19. A copy of 40 CFR pt. 60, subp. A is included in Appendix C. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than 3 years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 60.4218, 40 CFR 63.6590(c), 40 CFR pt. 60, subp. A, 40 CFR pt. 60, subp. IIII(Table 8), Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.0050, Minn. R. 7011.2305, Minn. R. 7011.8150, Minn. R. 7017.1010 & 7017.2025, Minn. R. 7019.0100]
EQUI 43	19530	1545772	EQUI 43 is a new affected source as defined under 40 CFR pt. 63, subp. ZZZZ, and the facility is an area source as defined at 40 CFR 63.2. The Permittee shall meet the requirements of 40 CFR pt. 63, subp. ZZZZ by meeting the requirements of 40 CFR pt. 60, subp. IIII. No further requirements of 40 CFR pt. 63, subp. ZZZZ apply to EQUI 43. [40 CFR 63.6590(c), Minn. R. 7011.8150]
EQUI 43	28030	1545773	The Permittee must comply with all applicable requirements of 40 CFR pt. 60, subp. IIII as follows: 40 CFR 60.4200(a)(2)(i); 40 CFR 60.4202(a)(2); 40 CFR 60.4205(b); 40 CFR 60.4206; 40 CFR 60.4207(b); 40 CFR 60.4208(a); 40 CFR 60.4209(a); 40 CFR 60.4211(a); 40 CFR 60.4211(c); 40 CFR 60.4211(f)(1); 40 CFR 60.4211(f)(2)(i); 40 CFR 60.4211(f)(3); 40 CFR 60.4214(b); 40 CFR 60.4218; 40 CFR 60.4219; and 40 CFR pt. 60, subp. IIII, Table 8. A copy of 40 CFR pt. 60, subp. IIII is included in Appendix G. If the standard changes or upon adoption of a new or amended federal applicable requirement, and if there are more than three years remaining in the permit term, the Permittee shall file an application for an amendment within nine months of promulgation of the applicable requirement, pursuant to Minn. R. 7007.0400, subp. 3. [40 CFR 63.6590(c), 40 CFR pt. 60, subp. IIII, Minn. R. 7007.0400, subp. 3, Minn. R. 7007.1150-7007.1500, Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 43	28040	1545774	The Permittee must limit emissions of NMHC+NOx <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 43	28041	1545775	The Permittee must limit emissions of NMHC+NOx <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28050	1545776	The Permittee must limit emissions of Particulate Matter <= 0.15 grams per horsepower-hour 24-hour rolling average (0.20 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28051	1545777	The Permittee must limit emissions of Particulate Matter <= 0.25 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28052	1545778	The Permittee must limit emissions of PM < 10 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28053	1545779	The Permittee must limit emissions of PM < 10 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28054	1545780	The Permittee must limit emissions of PM < 2.5 micron <= 0.16 grams per horsepower-hour 24-hour rolling average (0.22 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28055	1545781	The Permittee must limit emissions of PM < 2.5 micron <= 0.29 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28060	1545782	The Permittee must limit emissions of Carbon Monoxide <= 2.6 grams per horsepower-hour 24-hour rolling average (3.5 g/kW-hr). [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28061	1545783	The Permittee must limit emissions of Carbon Monoxide <= 4.44 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28062	1545784	The Permittee must limit emissions of Volatile Organic Compounds <= 4.8 grams per horsepower-hour 24-hour rolling average (6.4 g/kW-hr). [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28063	1545785	The Permittee must limit emissions of Volatile Organic Compounds <= 8.12 pounds per hour 3-hour average. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28064	1545786	The Permittee must limit emissions of Carbon Dioxide Equivalent <= 231 tons per year 12-month rolling sum. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28070	1545787	The Permittee must limit emissions of Opacity <= 20 percent opacity during the acceleration mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28080	1545788	The Permittee must limit emissions of Opacity <= 15 percent opacity during the lugging mode. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28090	1545789	The Permittee must limit emissions of Opacity <= 50 percent opacity during the peaks in either the acceleration or lugging modes. [40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
EQUI 43	28170	1545790	The Permittee must limit Sulfur Content of Fuel <= 15.0 parts per million and either a minimum cetane index of 40 or a maximum aromatic content of 35 percent by volume, as required by 40 CFR 1090.305. [40 CFR 60.4207(b), 40 CFR 63.6590(c), Minn. R. 7011.2305, Minn. R. 7011.8150]
EQUI 43	28171	1545791	Monthly recordkeeping: By the 15th of the month, the Permittee shall calculate and record the total amount of fuel burned for the previous month in mmBtu in EQUI 43. The Permittee shall then use that amount to calculate total greenhouse gas emissions in tons per month for the previous month using the following equation: GHG = ((MD * 163.05) + ((MD * 0.0066) * 25) + ((MD * 0.0013) * 298)) / 2000 Where: GHG = monthly greenhouse gas emissions in tons; MD = mmBtu of diesel fuel burned in the previous month; 163.05 = CO2 emission factor for diesel fuel in lb/mmBtu; 0.0066 = CH4 emission factor for diesel fuel in lb/mmBtu; 0.0013 = N2O emission factor for diesel fuel in lb/mmBtu; 25 = global warming potential for CH4; 298 = global warming potential for N2O; 2000 = conversion factor lb/ton. By the 15th of the month the Permittee shall calculate the 12 month rolling sum of GHG emissions from EQUI 43 by summing the monthly emissions of GHG, in tons, for the previous 12 months. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
EQUI 43	28172	1545792	Best Management Practices for Reciprocating Internal Combustion Engines (RICE) 1. The Permittee shall only use diesel fuel with a sulfur content of less than or equal to 15 ppm in the emergency engine. 2. The Permittee may not install a rain cap on any emergency engine stack. 3. The Permittee may install and operate a hinged flapper which is opened by the exhaust flow from the emergency engine stack. There shall be no flow obstruction at the point of discharge that inhibits vertical dispersion. The Permittee shall inspect the hinged flapper (i.e. tip-up rain cap) once per calendar month to make sure it is operating per the manufacturer's specifications and is not impeding the vertical flow of exhaust from the emergency engine stack. The Permittee shall keep records of these monthly inspections. 4. The Permittee shall make the test runs for each engine as short as allowed by insurance and building code considerations. 5. The testing for an emergency engine shall not occur while another emergency engine is being tested. 6. No testing shall be conducted on a day the Air Quality Index (AQI) or the forecasted AQI exceeds 90 unless the test cannot be deferred. For testing conducted on a day with the AQI above 90, document the reason it was not possible to defer the test and any actions that were taken to limit emissions during the test with the testing records. [Minn. R. 7007.0800, subps. 4-5, Title I Condition: 40 CFR 52.21(k)(modeling) and Minn. R. 7007.3000]
EQUI 43	28173	1545793	Air Quality Index (AQI) The AQI and the forecasted AQI can be found at: http://www.pca.state.mn.us/index.php/air/air-quality-and-pollutants/general-air-quality/air-quality-index/current-air-quality-index.html. [Minn. R. 7007.0800, subp. 2(A)]
FUGI 1	1	1529654	Comply with Fugitive Emission Control Plan: The Permittee shall follow the actions and recordkeeping specified in the fugitive dust control plan in Appendix H of this permit. If the Commissioner determines the Permittee is out of compliance with Minn. R. 7011.0150 or the fugitive control plan, then the Permittee may be required to amend the control plan and/or to install and operate particulate matter ambient monitors as requested by the Commissioner. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 1	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 1	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 1	3141	1528274	The Permittee shall vent emissions from EQUI 23 to TREA 1 whenever EQUI 23 operates, and operate and maintain TREA 1 at all times that any emissions are vented to TREA 1. The Permittee shall document periods of non-operation of the control equipment TREA 1 whenever EQUI 23 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 1	3142	1528275	If the Permittee replaces TREA 1, the replacement control must comply with all other requirements of TREA 1. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 1	3143	1528276	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Carbon Monoxide >= 90 percent control efficiency, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 1	3144	1528277	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Volatile Organic Compounds >= 90 percent control efficiency, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 1	3145	1531742	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
TREA 1	3146	1531743	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 1 so that the pressure drop across TREA 1 and TREA 2 does not change by more than 2.0 inches of water from the pressure drop across TREA 1 and TREA 2 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 1	3147	1528284	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 34) that continuously indicates and records the inlet temperature of TREA 1. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
TREA 1	3148	1528285	The Permittee shall operate and maintain TREA 1 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
TREA 1	3149	1528286	For periods when TREA 1 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 1 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 1 CO, VOC control efficiency limit specified in this permit; or b. The overall TREA 1 CO, VOC control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
TREA 1	3150	1528292	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 34) and pressure drop (EQUIs 35, 36) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
TREA 1	3151	1528297	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 34) and pressure drop (EQUIs 35, 36) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 1 operation is required. [Minn. R. 7007.0800, subps. 4-5]
TREA 1	3152	1528298	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 34) and pressure drop monitors (EQUIs 35, 36) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 1	3153	1528299	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 1 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 1	3154	1528300	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 1 that includes all TREA 1 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 1	3155	1528301	Corrective Actions: If TREA 1 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 1 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 1 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 1 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 2	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

SI Id	Sequence	ID	Requirement
TREA 2	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 2	3141	1528302	The Permittee shall vent emissions from EQUI 23 to TREA 2 whenever EQUI 23 operates, and operate and maintain TREA 2 at all times that any emissions are vented to TREA 2. The Permittee shall document periods of non-operation of the control equipment TREA 2 whenever EQUI 23 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 2	3142	1528303	If the Permittee replaces TREA 2, the replacement control must comply with all other requirements of TREA 2. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 2	3143	1528304	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Nitrogen Oxides >= 90 percent control efficiency. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 2	3144	1532590	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 23. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 2	3145	1532591	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 2 so that the pressure drop across TREA 1 and TREA 2 does not change by more than 2.0 inches of water from the pressure drop across TREA 1 and TREA 2 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 23, or upon commencement of normal operation of EQUI 23, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 2	3146	1532592	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 34) that continuously indicates and records the inlet temperature of TREA 2. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
TREA 2	3147	1532593	The Permittee shall operate and maintain TREA 2 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
TREA 2	3148	1532594	For periods when TREA 2 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 2 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 2 NOx control efficiency limit specified in this permit; or b. The overall TREA 2 NOx control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
TREA 2	3149	1532595	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 34) and pressure drop (EQUIs 35, 36) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
TREA 2	3150	1532596	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 34) and pressure drop (EQUIs 35, 36) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 2 operation is required. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
TREA 2	3151	1532597	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 34) and pressure drop monitors (EQUIs 35, 36) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 2	3152	1532598	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 2 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 2	3153	1532599	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 2 that includes all TREA 2 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 2	3154	1532600	Corrective Actions: If TREA 2 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 2 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 2 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 2 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 3	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 3	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 3	3141	1528345	The Permittee shall vent emissions from EQUI 24 to TREA 3 whenever EQUI 24 operates, and operate and maintain TREA 3 at all times that any emissions are vented to TREA 3. The Permittee shall document periods of non-operation of the control equipment TREA 3 whenever EQUI 24 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 3	3142	1528346	If the Permittee replaces TREA 3, the replacement control must comply with all other requirements of TREA 3. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 3	3143	1528347	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Carbon Monoxide >= 90 percent control efficiency, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 3	3144	1528348	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Volatile Organic Compounds >= 90 percent control efficiency, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 3	3145	1531746	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
TREA 3	3146	1531747	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 3 so that the pressure drop across TREA 3 and TREA 4 does not change by more than 2.0 inches of water from the pressure drop across TREA 3 and TREA 4 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 3	3147	1528349	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 37) that continuously indicates and records the inlet temperature of TREA 3. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
TREA 3	3148	1528350	The Permittee shall operate and maintain TREA 3 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
TREA 3	3149	1528351	For periods when TREA 3 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 3 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 3 CO, VOC control efficiency limit specified in this permit; or b. The overall TREA 3 CO, VOC control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
TREA 3	3150	1528352	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 37) and pressure drop (EQUIs 38, 39) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
TREA 3	3151	1528353	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 37) and pressure drop (EQUIs 38, 39) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 3 operation is required. [Minn. R. 7007.0800, subps. 4-5]
TREA 3	3152	1528354	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 37) and pressure drop monitors (EQUIs 38, 39) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 3	3153	1528355	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 3 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 3	3154	1528356	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 3 that includes all TREA 3 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 3	3155	1528357	Corrective Actions: If TREA 3 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 3 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 3 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 3 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 4	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

SI Id	Sequence	ID	Requirement
TREA 4	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 4	3141	1528375	The Permittee shall vent emissions from EQUI 24 to TREA 4 whenever EQUI 24 operates, and operate and maintain TREA 4 at all times that any emissions are vented to TREA 4. The Permittee shall document periods of non-operation of the control equipment TREA 4 whenever EQUI 24 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 4	3142	1528376	If the Permittee replaces TREA 4, the replacement control must comply with all other requirements of TREA 4. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 4	3143	1528377	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Nitrogen Oxides >= 90 percent control efficiency. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 4	3144	1532612	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 24. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 4	3145	1532613	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 4 so that the pressure drop across TREA 3 and TREA 4 does not change by more than 2.0 inches of water from the pressure drop across TREA 3 and TREA 4 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 24, or upon commencement of normal operation of EQUI 24, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 4	3146	1532614	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 37) that continuously indicates and records the inlet temperature of TREA 4. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
TREA 4	3147	1532615	The Permittee shall operate and maintain TREA 4 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
TREA 4	3148	1532616	For periods when TREA 4 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 4 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 4 NOx control efficiency limit specified in this permit; or b. The overall TREA 4 NOx control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
TREA 4	3149	1532617	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 37) and pressure drop (EQUIs 38, 39) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
TREA 4	3150	1532618	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 37) and pressure drop (EQUIs 38, 39) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 4 operation is required. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
TREA 4	3151	1532619	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 37) and pressure drop monitors (EQUIs 38, 39) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 4	3152	1532620	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 4 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 4	3153	1532621	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 4 that includes all TREA 4 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 4	3154	1532622	Corrective Actions: If TREA 4 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 4 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 4 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 4 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 5	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 5	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 5	3141	1528332	The Permittee shall vent emissions from EQUI 25 to TREA 5 whenever EQUI 25 operates, and operate and maintain TREA 5 at all times that any emissions are vented to TREA 5. The Permittee shall document periods of non-operation of the control equipment TREA 5 whenever EQUI 25 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 5	3142	1528333	If the Permittee replaces TREA 5, the replacement control must comply with all other requirements of TREA 5. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 5	3143	1528334	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Carbon Monoxide >= 90 percent control efficiency, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 5	3144	1528335	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Volatile Organic Compounds >= 90 percent control efficiency, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 5	3145	1531744	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]

SI Id	Sequence	ID	Requirement
TREA 5	3146	1531745	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 5 so that the pressure drop across TREA 5 and TREA 6 does not change by more than 2.0 inches of water from the pressure drop across TREA 5 and TREA 6 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 5	3147	1528336	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 40) that continuously indicates and records the inlet temperature of TREA 5. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
TREA 5	3148	1528337	The Permittee shall operate and maintain TREA 5 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
TREA 5	3149	1528338	For periods when TREA 5 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 5 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 5 CO, VOC control efficiency limit specified in this permit; or b. The overall TREA 5 CO, VOC control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
TREA 5	3150	1528339	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 40) and pressure drop (EQUIs 41, 42) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
TREA 5	3151	1528340	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 40) and pressure drop (EQUIs 41, 42) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 5 operation is required. [Minn. R. 7007.0800, subps. 4-5]
TREA 5	3152	1528341	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 40) and pressure drop monitors (EQUIs 41, 42) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 5	3153	1528342	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 5 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 5	3154	1528343	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 5 that includes all TREA 5 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 5	3155	1528344	Corrective Actions: If TREA 5 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 5 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 5 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 5 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 6	3130	1482576	The Permittee shall submit a notification of the date construction began: Due 30 calendar days after Date of Construction Start (or reconstruction). Submit the name and number of the Subject Item and the date construction began. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]

SI Id	Sequence	ID	Requirement
TREA 6	3140	1243493	The Permittee shall submit a notification of the actual date of initial startup: Due 15 calendar days after Initial Startup Date. Submit the name and number of the Subject Item and the date of startup. Startup is as defined in Minn. R. 7005.0100, subp. 42a. The notification shall be submitted electronically on Form CS-02. [Minn. R. 7007.0800, subp. 16(L)]
TREA 6	3141	1528363	The Permittee shall vent emissions from EQUI 25 to TREA 6 whenever EQUI 25 operates, and operate and maintain TREA 6 at all times that any emissions are vented to TREA 6. The Permittee shall document periods of non-operation of the control equipment TREA 6 whenever EQUI 25 is operating. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 6	3142	1528364	If the Permittee replaces TREA 6, the replacement control must comply with all other requirements of TREA 6. Prior to making such a change, the Permittee shall apply for and obtain the appropriate permit amendment, as applicable. If no amendment is needed for the replacement, the Permittee shall submit an electronic notice to the Agency using form CR-05. The notice must be received by the Agency seven working days prior to the commencement/Start of replacement. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 6	3143	1528365	The Permittee shall operate and maintain control equipment such that it achieves a control efficiency for Nitrogen Oxides >= 90 percent control efficiency. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 6	3144	1532601	The Permittee must limit Temperature >= 484 and <= 1350 degrees Fahrenheit, except during startup of EQUI 25. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 6	3145	1532602	Pressure Drop <= 2.0 inches of water. When operating at 100 percent load plus or minus 10 percent, the Permittee shall maintain TREA 6 so that the pressure drop across TREA 5 and TREA 6 does not change by more than 2.0 inches of water from the pressure drop across TREA 5 and TREA 6 that was measured during the initial performance test, and subsequently as stated in a Notice of Compliance (NOC) for the most recent test. Prior to the initial performance test a pressure drop less than 16.0 inches of water. This limit applies after 241 hours of burn-in operation of EQUI 25, or upon commencement of normal operation of EQUI 25, whichever comes first. [Title I Condition: 40 CFR 52.21(j)(BACT) and Minn. R. 7007.3000]
TREA 6	3146	1532603	The Permittee shall maintain and operate a thermocouple monitoring device (EQUI 40) that continuously indicates and records the inlet temperature of TREA 6. The thermocouple shall have a margin of error less than the greater of +/- 0.75 percent of the temperature being measured or +/- 4.5 degrees Fahrenheit. The recording device shall also calculate the four-hour rolling average inlet temperature. [Minn. R. 7007.0800, subps. 4-5]
TREA 6	3147	1532604	The Permittee shall operate and maintain TREA 6 in accordance with the Operation and Maintenance (O & M) Plan. The Permittee shall keep copies of the O & M Plan available onsite for use by staff and MPCA staff. [Minn. R. 7007.0800, subp. 14]
TREA 6	3148	1532605	For periods when TREA 6 is operated at an inlet temperature at or above the permitted minimum and below or at the permitted maximum, and the TREA 6 pressure drop is no more than 2.0 inches of water higher or lower than the value recorded during the initial performance test, the Permittee shall use either one of the following when completing calculations as required elsewhere in this permit: a. The overall TREA 6 NOx control efficiency limit specified in this permit; or b. The overall TREA 6 NOx control efficiency determined during the most recent MPCA approved performance test. If the tested efficiency is less than the efficiency limit in this permit, this shall be reported as a deviation and the Permittee must use the tested value in all calculations until the efficiency is demonstrated to be above the permit limit through a new test. [Minn. R. 7007.0800, subps. 4-5]
TREA 6	3149	1532606	Daily Monitoring: The Permittee shall physically verify the operation of the thermocouple temperature (EQUI 40) and pressure drop (EQUIs 41, 42) recording device at least once each operating day to verify they are working and recording properly. The Permittee shall maintain a written record of the daily verifications. [Minn. R. 7007.0800, subps. 4-5]
TREA 6	3150	1532607	Monitoring Equipment: The Permittee shall maintain the thermocouple (EQUI 40) and pressure drop (EQUIs 41, 42) equipment to conduct temperature and pressure drop monitoring, respectively, required by this permit. The thermocouple must be installed, in use, and properly maintained whenever TREA 6 operation is required. [Minn. R. 7007.0800, subps. 4-5]

SI Id	Sequence	ID	Requirement
TREA 6	3151	1532608	Annual Calibration: The Permittee shall calibrate the thermocouple temperature monitor (EQUI 40) and pressure drop monitors (EQUIs 41, 42) each at least once every 12 months and shall maintain a written record of the calibrations and any action resulting from the calibrations. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 6	3152	1532609	Quarterly Inspections: At least once per calendar quarter, the Permittee shall inspect the TREA 6 internal and external system components. The Permittee shall maintain a written record of the inspection and any corrective actions taken resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 6	3153	1532610	Annual Inspection: At least once per calendar year, the Permittee shall conduct an internal inspection of TREA 6 that includes all TREA 6 operating systems. The Permittee shall maintain a written record of the inspection and any action resulting from the inspection. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]
TREA 6	3154	1532611	Corrective Actions: If TREA 6 is operated at an inlet temperature below the permitted minimum or above the permitted maximum, or the TREA 6 pressure drop differs by more than 2.0 inches of water from the value recorded during the initial performance test, or if TREA 6 or any of its components are found during the inspections to need repair, the Permittee shall take corrective action as soon as possible. Corrective actions shall return the temperature to at least the permitted minimum, return the pressure drop to the value listed in this permit, and/or include completion of necessary repairs identified during the inspection, as applicable. Corrective actions include, but are not limited to, those outlined in the TREA 6 O & M Plan. The Permittee shall keep a record of the type and date of any corrective action taken. [Minn. R. 7007.0800, subp. 14, Minn. R. 7007.0800, subps. 4-5]

Attachment 3 - BACT Analysis

Best Available Control Technology Analysis

Appendix I to the Permit Application for Blue Lake Conversion Project

Prepared for
Xcel Energy – Blue Lake

December 2022

Updated May 2024

4300 MarketPointe Drive, Suite 200
Minneapolis, MN 55435
952.832.2600
www.barr.com

Best Available Control Technology Analysis
Blue Lake Conversion Project

December 2022

Contents

1 Executive Summary 1

2 Process Description Summary and BACT Applicability 1

2.1 Process Description Summary 1

2.2 BACT Applicability 2

3 BACT Methodology 4

3.1 Top-Down BACT Approach 4

3.1.1 Step 1 - Identify all Available Control Technologies 4

3.1.2 Step 2 - Eliminate Technically Infeasible Control Technologies 5

3.1.3 Step 3 – Rank Technically Feasible Control Technologies by Control Effectiveness 5

3.1.4 Step 4 - Evaluate Technically Feasible Control Technologies 5

3.1.5 Step 5 - Select BACT 7

3.2 Form of BACT Emission Limits 7

3.3 Constraints on BACT Emission Limits 8

3.4 Compliance with BACT Emission Limits during Startup, Shutdown and Malfunction (SSM) Situations 8

4 BACT for the Combustion Turbines 10

4.1 Combustion Turbines PM, PM_{10}, $PM_{2.5}$ Emissions 10

4.1.1 Step 1 – Identify All Available Control Technologies 10

4.1.2 Step 2 – Technical Feasibility of Control Technologies 10

4.1.3 Step 3 – Effectiveness of Feasible Control Technologies 11

4.1.4 Step 4 – Evaluation of Feasible Control Technologies 11

4.1.5 Step 5 – BACT Selection 11

4.2 Combustion Turbines NO_X Emissions 12

4.2.1 Step 1 – Identify All Available Control Technologies 12

4.2.2 Step 2 – Technical Feasibility of Control Technologies 14

4.2.3 Step 3 – Effectiveness of Feasible Control Technologies 15

4.2.4 Step 4 – Evaluation of Feasible Control Technologies 15

4.2.5 Step 5 – BACT Selection 16

4.3 Combustion Turbines CO and VOC Emissions 17
4.3.1 Step 1 – Identify All Available Control Technologies 17
4.3.2 Step 2 – Technical Feasibility of Control Technologies 17
4.3.3 Step 3 – Effectiveness of Feasible Control Technologies 18
4.3.4 Step 4 – Evaluation of Feasible Control Technologies 18
4.3.5 Step 5 – BACT Selection 19
4.4 Combustion Turbines GHG Emissions 20
5 BACT for the Dual Fuel Engine Generators 21
5.1 Engine Generators $PM/PM_{10}/PM_{2.5}$ Emissions 21
5.1.1 Step 1 – Identify All Available Control Technologies 21
5.1.2 Step 2 – Technical Feasibility of Control Technologies 21
5.1.3 Step 3 – Effectiveness of Feasible Control Technologies 22
5.1.4 Step 4 – Evaluation of Feasible Control Technologies 23
5.1.5 Step 5 – BACT Selection 23
5.2 Engine Generators NO_X Emissions 24
5.2.1 Step 1 – Identify All Available Control Technologies 24
5.2.2 Step 2 – Technical Feasibility of Control Technologies 25
5.2.3 Step 3 – Effectiveness of Feasible Control Technologies 26
5.2.4 Step 4 – Evaluation of Feasible Control Technologies 26
5.2.5 Step 5 – BACT Selection 26
5.3 Engine Generators CO/VOC Emissions 27
5.3.1 Step 1 – Identify All Available Control Technologies 27
5.3.2 Step 2 – Technical Feasibility of Control Technologies 28
5.3.3 Step 3 – Effectiveness of Feasible Control Technologies 28
5.3.4 Step 4 – Evaluation of Feasible Control Technologies 29
5.3.5 Step 5 – BACT Selection 29
6 BACT for Emergency Diesel Engine Generators 30
6.1 Emergency Diesel Engine Generators $PM/PM_{10}/PM_{2.5}$ Emissions 30
6.1.1 Step 1 – Identify All Available Control Technologies 30
6.1.2 Step 2 – Technical Feasibility of Control Technologies 30
6.1.3 Step 3 – Effectiveness of Feasible Control Technologies 31
6.1.4 Step 4 – Evaluation of Feasible Control Technologies 31
6.1.5 Step 5 – BACT Selection 31
6.2 Emergency Diesel Engine Generators NO_X Emissions 32

6.2.1 Step 1 – Identify All Available Control Technologies 32
6.2.2 Step 2 – Technical Feasibility of Control Technologies 33
6.2.3 Step 3 – Effectiveness of Feasible Control Technologies 34
6.2.4 Step 4 – Evaluation of Feasible Control Technologies 34
6.2.5 Step 5 – BACT Selection 34
6.3 Emergency Diesel Engine Generators CO/VOC Emissions 35
6.3.1 Step 1 – Identify All Available Control Technologies 35
6.3.2 Step 2 – Technical Feasibility of Control Technologies 35
6.3.3 Step 3 – Effectiveness of Feasible Control Technologies 36
6.3.4 Step 4 – Evaluation of Feasible Control Technologies 36
6.3.5 Step 5 – BACT Selection 36
6.4 Emergency Generators GHG Emissions 37
7 Facility-wide Combustion Sources GHG BACT 38
7.1 Combustion Turbines, Engine Generators, and Emergency Engines GHG Emissions 38
7.1.1 Step 1 – Identify All Available Control Technologies 38
7.1.2 Step 2 – Technical Feasibility of Control Technologies 40
7.1.3 Step 3 - Effectiveness of Feasible Control Technologies 43
7.1.4 Step 4 - Evaluation of Feasible Control Technologies 44
7.1.5 Step 5 – BACT Selection 45
8 References 47

List of Tables

Table I.1-1 Summary of Emission Units and Pollutants Subject to BACT 2
Table I.1-2 Gas Turbine BACT Limits 1
Table I.1-3 Wartsila 9.37 MW Diesel and Dual Fuel (DF, Natural Gas/Diesel) Generator BACT Limits 2
Table I.1-4 Emergency Generators BACT Limits 3
Table I.2-1 Summary of Emission Increase 2
Table I.3-1 NSPS and NESHAPS Establishing BACT "Floor" 8
Table I.4-1 Available PM, PM_{10}, $PM_{2.5}$, Emission Control Technologies for the Combustion Turbines. 10
Table I.4-2 Technical Feasibility of PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Combustion Turbines 10
Table I.4-3 Ranking of Remaining PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Combustion Turbines 11
Table I.4-4 Proposed BACT PM, PM_{10}, $PM_{2.5}$ Limits for the Combustion Turbines 12
Table I.4-5 Available NO_X Emission Control Technologies for the Combustion Turbines 13
Table I.4-6 Technical Feasibility of NO_X Emission Control Technologies for the Combustion Turbines 14
Table I.4-7 Ranking of Remaining NO_X Emission Control Technologies for the Combustion Turbines 15
Table I.4-8 Cost Effectiveness of NO_X Emission Control Technologies for the Combustion Turbines . 15
Table I.4-9 Environmental Impacts of NO_X Control Technologies for the Combustion Turbines 16
Table I.4-10 Energy Impacts of NO_X Control Technologies for the Combustion Turbines 16
Table I.4-11 Proposed BACT NO_X Limitations for the Combustion Turbines 17
Table I.4-12 Available CO and VOC Emission Control Technologies for the Combustion Turbines 17
Table I.4-13 Technical Feasibility of CO and VOC Control Technologies for the Combustion Turbines 18
Table I.4-14 Ranking of Remaining CO/VOC Emission Control Technologies for the Combustion Turbines 18
Table I.4-15 Cost Effectiveness of CO/VOC Emission Control Technologies for the Combustion Turbines 19
Table I.4-16 Proposed BACT CO and VOC Limitations for the Combustion Turbines 19
Table I.5-1 Available PM, PM_{10}, $PM_{2.5}$, Emission Control Technologies for the Engine Generators 21
Table I.5-2 Technical Feasibility of PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Engine Generators 22
Table I.5-3 Ranking of Remaining PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Engine Generators 23
Table I.5-4 Proposed PM, PM_{10}, $PM_{2.5}$ BACT Limits for the Engine Generators 24
Table I.5-5 Available NO_X Emission Control Technologies for the Engine Generators 25
Table I.5-6 Technical Feasibility of NO_X Emission Control Technologies for the Engine Generators 25

Table I.5-7 Ranking of Remaining NO_X Emission Control Technologies for the Engine Generators 26
Table I.5-8 Proposed BACT NO_X Limitations for the Engine Generators 27
Table I.5-9 Available CO/VOC Emission Control Technologies for the Engine Generators 28
Table I.5-10 Technical Feasibility of CO/VOC Emission Control Technologies for the Engine Generators 28
Table I.5-11 Ranking of Remaining CO/VOC Emission Control Technologies for the Engine Generators 28
Table I.5-12 Proposed BACT CO/VOC Limitations for the Engine Generators 29
Table I.6-1 Available PM, PM_{10}, $PM_{2.5}$, Emission Control Technologies for the Emergency Diesel Engine Generators 30
Table I.6-2 Technical Feasibility of PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Emergency Diesel Engine Generators 31
Table I.6-3 Ranking of Remaining PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Emergency Diesel Engine Generators 31
Table I.6-4 Proposed PM, PM_{10}, $PM_{2.5}$ BACT Limits for the Emergency Diesel Engine Generators 32
Table I.6-5 Available NO_X Emission Control Technologies for the Emergency Diesel Engine Generators 33
Table I.6-6 Technical Feasibility of NO_X Emission Control Technologies for the Emergency Diesel Engine Generators 33
Table I.6-7 Ranking of Remaining NO_X Emission Control Technologies for the Emergency Diesel Engine Generators 34
Table I.6-8 Proposed BACT NO_X Limitations for the Emergency Generators 35
Table I.6-9 Available CO/VOC Emission Control Technologies for the Emergency Diesel Engine Generators 35
Table I.6-10 Technical Feasibility of CO/VOC Emission Control Technologies for the Emergency Diesel Engine Generators 36
Table I.6-11 Ranking of Remaining CO/VOC Emission Control Technologies for the Emergency Diesel Engine Generators 36
Table I.6-12 Proposed BACT CO/VOC Limitations for the Emergency Generators 37
Table I.7-1 Available GHG Emission Control Technologies 38
Table I.7-2 Technical Feasibility of CO_2 Control Technologies for the Combustion Turbines 40
Table I.7-3 Technical Feasibility of CO_2 Control Technologies for the Engine Generators 40
Table I.7-4 Technical Feasibility of CO_2 Control Technologies for the Emergency Generators 41
Table I.7-5 Technical Feasibility of Energy Efficiency Measures for Reducing GHG Emissions from the Combustion Turbines 43
Table I.7-6 Economic Feasibility of CCUS for CO_2 Emissions at the Facility 44
Table I.7-7 Proposed GHG BACT Limits for the Combustion Turbines 45
Table I.7-8 Proposed GHG BACT Limits for Engine Generators 45
Table I.7-9 Proposed GHG BACT Limits for Emergency Engines 46
Table I.7-10 Global Warming Potentials used for Compliance Monitoring 46

List of Attachments

Attachment I.1 Control Cost
- Attachment I.1-1 Combustion Turbines NOX Control Costs
- Attachment I.1-2 Combustion Turbines CO/VOC Control Costs
- Attachment I.1-3 GHG Control Costs

Attachment I.2 RACT/BACT/LAER Clearinghouse Summary
- Attachment I.2-1 Combustion Turbine RBLC
- Attachment I.2-2 Engine Generator RBLC
- Attachment I.2-3 Emergency Generator RBLC

Attachment I.3 Engine Generator Manufacturer (Wartsila) Diesel Particulate Filter Memo
Attachment I.4 Fugitive Dust Control Plan

1 Executive Summary

Xcel Energy (Xcel) is submitting a major permit amendment application for the Blue Lake Conversion Project ("the Project") which includes the following updates at the facility:

- Retire the four Turbodyne combustion turbines (CTs) (EQUI 1, EQUI 2, EQUI 3, and EQUI 4)
- Modify the synthetic minor emission limits as presented in the facility air permit (COMG 2) for the two General Electric natural gas fired CTs (EQUI 7 and EQUI 8) to allow increased utilization
- Install three (3) 9.37 MW Wartsila dual fuel (natural gas and diesel) internal combustion engine generators
- Install five (5) diesel-fired emergency generators

The Project will trigger the Prevention of Significant Deterioration (PSD) requirements as summarized in Section 2.2. A detailed description of the Project can be found in the permit application narrative.

The natural gas-fired turbines were originally installed with synthetic minor limits such that Prevention of Significant Deterioration (PSD) permitting requirements did not apply. Xcel now seeks to revise these limits which will require a PSD permit per 40 CFR 52.21(r)(4).

The proposed project is a major modification for stationary sources[1] subject to PSD permitting requirements for the following pollutants.

- Particulates Matter (PM) meaning PM-Total (filterable + condensable fractions)
- Particulate Matter with an Aerodynamic Diameter of less than 10 Microns (PM_{10})
- Particulate Matter with an Aerodynamic Diameter of less than 2.5 Microns ($PM_{2.5}$)
- Nitrogen Oxides (NO_X)
- Carbon Monoxide (CO)
- Volatile Organic Compounds (VOC)
- Greenhouse Gases (GHG)

Xcel is required to apply Best Available Control Technology (BACT) for New Source Review (NSR) pollutants for which a significant emissions increase occurs and for greenhouse gases where applicable.[2] BACT is applied to each emissions unit (EU) at which an emissions increase would occur as a result of a

[1] 40 CFR Part 52.21(b)(1)(i)
[2] 40 CFR Part 52.21(j)(3)

physical change or change in the method of operation of the unit. Table I.1-1 lists the Project-related emission units and pollutants subject to BACT requirements.

Table I.1-1 Summary of Emission Units and Pollutants Subject to BACT

Emissions Unit	EU ID #	PSD Pollutants Emitted
Combustion Turbine 7	EQUI 7	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
Combustion Turbine 8	EQUI 8	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
New Engine Generator 1	EQUI 23	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
New Engine Generator 2	EQUI 24	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
New Engine Generator 3	EQUI 25	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
Emergency Generator 2 (New)	EQUI 26	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
Emergency Generator 3 (New)	EQUI 27	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
Emergency Generator 4 (New)	EQUI 28	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
Emergency Generator 5 (New)	EQUI 29	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG
Emergency Generator 6 (New)	EQUI 43	PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, GHG

This BACT analysis follows the U.S. Environmental Protection Agency's (EPA) five-step top-down approach, as specified in the EPA's draft New Source Review Workshop Manual (reference (1)).

- Step 1 – Identify All Available Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Control Technologies and Document Results
- Step 5 – Select BACT

Table I.1-2 to Table I.1-4 summarize the results of the BACT analysis. Details regarding the basis for the emission rates and cost analysis are provided in subsequent sections of this report.

Table I.1-2 Gas Turbine BACT Limits

Pollutant	Proposed BACT	Limit Type	Limit	Units	Basis	Compliance Demonstration
PM, PM_{10}, and $PM_{2.5}$	Good combustion practices and clean fuel (100% natural gas)	Performance	0.0066	Lb/MMBtu	AP-42	Initial Performance Test EPA Method 5 and EPA Method 202 followed by reoccurring tests every five years after, combust only natural gas, good combustion practices. Emissions during startup, shutdown, or emergencies are not expected to change from normal operations.
		Mass	13.48	Lb/hr, 3-hr average		
NO_X	Dry Low NO_X burner	Performance	11	ppm (dry basis), 15% O_2, 24-hr average	Existing performance data	NO_X CEMS
		Mass (normal operations)	73.51	lb/hr, 24-hr average		
		Startup/Shutdown and Emergency Operation	14.05	tpy		Good combustion practices
CO	Good combustion practices	Performance	9	ppm (dry basis), 15% O_2, 24-hr average	Existing performance data	CO CEMS
		Mass (normal operations)	38.80	lb/hr, 24-hr average		
		Startup/Shutdown and Emergency Operation	24.70	tpy		Good combustion practices
VOC (As Methane)	Good combustion practices	Performance	4.6	ppm (dry basis), actual O_2, 3-hr average	Proposed BACT limit based on other Xcel combustion turbines	Initial Performance Test Method 25A, average of three 1-hour test runs, thereafter use CO CEMS as a surrogate for VOC compliance
		Mass (normal operations)	10.03	lb/hr, 3-hr average		
		Startup/Shutdown and Emergency Operation	33.60	tpy		Good combustion practices
GHG	Use of natural gas fuel and implementation of the operational energy-efficiency measures	Performance	120	Lb CO_2/MMBtu	Natural gas combustion based limits in the RBLC	Combust only natural gas fuel, good combustion practices, and energy efficiency measures.
		Mass	986,539	tons CO_2e/yr (12-month rolling sum)		

Table I.1-3 Wartsila 9.37 MW Diesel and Dual Fuel (DF, Natural Gas/Diesel) Generator BACT Limits

Pollutant	Proposed BACT	Limit Type	Limit	Units	Basis	Compliance Demonstration
PM/ PM_{10}/ $PM_{2.5}$	Comply with applicable NSPS IIII requirements, ULSD or natural gas fuel, and good combustion practices	Performance 75% Load	DF – 0.10 Diesel – 0.22	g/kWhe filterable + condensable PM	Manufacturer specifications	$PM_{10}/PM_{2.5}$ - Initial Performance Test Method 5 and Method 202, average of three 1-hour test runs after shakedown followed by reoccurring tests every five years after, operate engine in accordance with manufacturer specifications, maintain records of fuel use. PM (filterable) – Method 5 testing must be conducted annually per 40 CFR 60.4211(d)(3) AND must be within 10% of peak load per 40 CFR 60.4213(a)
		Performance <75% Load	DF – 0.16 Diesel – 0.32	g/kWhe filterable + condensable PM		
		Performance (NSPS Limit)	0.15	g/kw-hr filterable PM		
		Mass (normal operations)	DF – 2.01 Diesel – 4.76	lb/hr		
		Startup/Shutdown and Emergency Operations	2.01	tpy		Good combustion practices
NO_X	Comply with applicable NSPS IIII requirements and selective catalytic reduction (SCR)	Performance 75% Load	DF – 0.09 Diesel – 0.53	g/kWhe	Manufacturer specifications	Performance Test Method 7E must be conducted annually per 40 CFR 60.4211(d)(3) AND must be within 10% of peak load per 40 CFR 60.4213(a), average of three 1-hour test runs, operate engine in accordance with manufacturer specifications, operate SCR equipment in accordance with manufacturer specifications except during startup and shutdown.
		Performance <75% Load	DF – 0.15 Diesel – 0.66	g/kWhe		
		Mass (normal operations)	DF – 1.65 Diesel - 10.86	lb/hr		
		Startup/Shutdown and Emergency Operations	17.98	tpy		Good combustion practices
CO	Oxidation catalyst and good combustion practices	Performance 75% Load	DF – 0.13 Diesel - 0.19	g/kWhe	Manufacturer specifications	Initial Performance Test Method 10, average of three 1-hour test runs after shakedown followed by reoccurring tests every five years after, operate engine and oxidation catalyst system in accordance with manufacturer specifications.
		Performance <75% Load	DF – 0.15 Diesel - 0.20	g/kWhe		
		Mass (normal operations)	DF – 2.51 Diesel – 3.78	lb/hr		
		Startup/Shutdown and Emergency Operations	4.21	tpy		Good combustion practices
VOC	Oxidation catalyst and good combustion practices	Performance 75% Load	DF – 0.17 Diesel – 0.21	g/kWhe as Methane	Manufacturer specifications	Initial Performance Test Method 25A, average of three 1-hour test runs after shakedown followed by reoccurring tests every five years after, operate engine and oxidation catalyst system in accordance with manufacturer specifications.
		Performance <75% Load	DF – 0.30 Diesel – 0.23	g/kWhe as Methane		
		Mass (normal operations)	DF – 3.26 Diesel – 4.33	lb/hr		
		Startup/Shutdown and Emergency Operations	1.32	tpy as Methane		Good combustion practices
GHG	Good combustion practices	Performance	DF – 512 Diesel - 672	g/kWhe CO_2	Manufacturer specifications	Good combustion practices, fuel use tracking, and recordkeeping.
		Mass (normal operations)	72,583	tons CO_2e/yr per (12-month rolling sum)		

Table I.1-4 Emergency Generators BACT Limits

Pollutant	Proposed BACT	Limit Type	Limit	Units	Basis	Compliance Demonstration
PM	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, ULSD fuel, limited operating hours, and good combustion practices	Performance	0.20	g/kW-hr	Includes filterable and condensable particulates. Filterable particulate emission factor is from Tier 2 diesel engine standards. Condensable emissions apply the fraction of condensable to filterable emission rates from AP-42 Chapter 3.4 – Large Station Diesel and Station Dual-fuel Engines	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, ultra-low sulfur diesel (ULSD) fuel, operate less than or equal to 500 hr/yr, and good combustion practices
		Mass (750 kW generator) Mass (550 kW generator)	0.35 0..25	Lb/hr		
PM_{10}		Performance	0.22	g/kW-hr		
		Mass (750 kW generator) Mass (550 kW generator)	0.39 0.29	Lb/hr		
$PM_{2.5}$		Performance	0.22	g/kW-hr		
		Mass (750 kW generator) Mass (550 kW generator)	0.39 0.29	Lb/hr		
Opacity		Performance	• 20%, • 15%, • 50%	• Acceleration mode • Lugging mode • Peaks in acceleration and lugging modes	Tier 2 diesel engine standards	
NO_X (NO_X + NMHC combined limit)	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, ULSD fuel, limited operating hours, and good combustion practices	Performance	6.4	g/kW-hr	Proposed limit is the sum of NO_X and NMHC (assumed equivalent to VOC) per Tier 2 diesel engine standards	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, ULSD fuel, operate less than or equal to 500 hr/yr, and good combustion practices
		Mass (750 kW generator) Mass (550 kW generator)	11.03 8.12	lb/hr		
CO	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, limited operating hours, and good combustion practices	Performance	3.5	g/kW-hr	Tier 2 diesel engine standards	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, operate less than or equal to 500 hr/yr, and good combustion practices
		Mass (750 kW generator) Mass (550 kW generator)	6.03 4.44	lb/hr		
VOC (NO_X + NMHC combined limit)	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, limited operating hours, and good combustion practices	Performance	6.4	g/kW-hr	Proposed limit is the sum of NO_X and NMHC (assumed equivalent to VOC) per Tier 2 diesel engine standards	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, operate less than or equal to 500 hr/yr, and good combustion practices
		Mass (750 kW generator) Mass (550 kW generator)	11.03 8.12	lb/hr		
GHG	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, ULSD fuel, limited operating hours, and good combustion practices	Performance[1]	N/A	g/kW-hr	40 CFR 98 calculation methodology for diesel combustion	Purchase a Tier 2 certified engine, comply with applicable NSPS IIII requirements, ULSD fuel, operate less than or equal to 500 hr/yr, and good combustion practices
		Mass (750 kW generator) Mass (550 kW generator)	314 231	tons CO_2e/calendar yr		

Notes:
To be classified as an emergency engine by NSPS IIII, non-emergency use is limited to 50 hr/yr within a total allowance of 100 hr/yr for maintenance and testing. Electrical demand peak shaving is not allowed. While there are no limits to emergency usage, the proposed BACT will limit the engine to 500 hr/yr for all operating scenarios.
[1] Xcel is only proposing a mass limit for the emergency engines because no changes can be made to unit operation to adjust GHG performance. Operate the engine in accordance with manufacturer specifications and track fuel usage for compliance.

2 Process Description Summary and BACT Applicability

2.1 Process Description Summary

The Xcel Energy - Blue Lake (Facility) is located at 1200 70th Street S in Shakopee, Scott County, Minnesota and operates under the terms and conditions of Air Permit 13900010-104. As currently permitted, the facility consists for the following emission sources:

- Four (4) simple cycle stationary combustion turbine (CT) generators manufactured by Turbodyne, installed in the 1970s and fired with distillate fuel oil No. 2:
  - EQUI 1: Combustion Turbine (50 megawatts (MW))
  - EQUI 2: Combustion Turbine (50 MW)
  - EQUI 3: Combustion Turbine (50 MW)
  - EQUI 4: Combustion Turbine (55 MW)
- A diesel fired emergency generator:
  - EQUI 5: Emergency Engine/Generator
- Two (2) CTs manufactured by General Electric, installed in 2004, fired with natural gas and equipped with dry low-NO_X combustors to inhibit NO_X formation:
  - EQUI 7: GE Dry Low-NO_X Burner Combustion Turbine 7 (174 MW)
  - EQUI 8: GE Dry Low-NO_X Burner Combustion Turbine 7 (174 MW)

The main air pollutants are products of combustion such as nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO2), volatile organic compounds (VOC), particulate matter (PM), particulate matter less than ten microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), hazardous air pollutants (HAPs), and greenhouse gases (GHG or CO_2e).

Xcel Energy is submitting a major permit amendment application for the Blue Lake Conversion Project ("the Project") which includes the following updates at the facility:

- Retire the four Turbodyne CTs (EQUI 1, EQUI 2, EQUI 3, and EQUI 4)
- Modify the synthetic minor emission limits as presented in the facility air permit (COMG 2) for the two General Electric CTs (EQUI 7 and EQUI 8) to allow increased utilization
- Install three (3) 9.37 MW Wartsila dual fuel (natural gas and diesel) internal combustion engine generators.

- Install five (5) diesel-fired emergency generators.

The Project will trigger the Prevention of Significant Deterioration (PSD) requirements as summarized in Section 2.2.

2.2 BACT Applicability

BACT is required for new units, modified units, and units for which there is a change in the method of operation. A physical change or change in the method of operation does not include an increase in the hours of operation or in the production rate, provided the increase does not exceed the operating design capacity of the major stationary source and the change is not prohibited by, or inconsistent with, an enforceable permit limit.

BACT is required for each regulated pollutant having the potential to be emitted in significant amounts. In the case of a major modification, the requirements for BACT apply only to each new or modified emissions unit at which a net emissions increase of the pollutant would occur. Table I.2-1 shows the total emissions increase from the Project, as described in the summary above, relative to the PSD significant emission rates (SER). Thus, the Project is considered a "major modification" for CO, NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, and GHG. Therefore, units which are new, physically modified, or have a change in the method of operation (i.e. increase in the permitted capacity or emission rate) are subject to BACT for these pollutants. Note: Combustion Turbines 7 and 8 are included in the total below at their full potential to emit because revising the synthetic minor limits on them requires that they go through PSD review per 52.21(r)(4).

Table I.2-1 Summary of Emission Increase

	CO	NO_X	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	CO_2e
Total Project Emissions Increase (tpy)	379	864	181	181	181	12	213	2,192,449
PSD SER (tpy)	100	40	25	15	10	40	40	75,000

Below is a brief description of each project element and why it is subject to BACT.

- **EQUI 7 (Combustion Turbine 7) and EQUI 8 (Combustion Turbine 8):** The Project will modify the synthetic minor emission limits as presented in the facility air permit (COMG 2) for the two General Electric CTs (EQUI 7 and EQUI 8) to allow increased utilization. This results in increases of CO, NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, and GHG emissions. The removal of synthetic minor limits requires PSD review per 40 CFR 52.21(r)(4).
- **Three (3) 9.37 MW Wartsila dual fuel (natural gas and diesel) internal combustion engine generators:** The engines can combust only diesel or a dual fuel (DF) mode with natural gas and a

small fraction of diesel to act as a pilot fuel so that the units can undergo compression ignition. This results in increases of CO, NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, and GHG emissions. The generators are new units and are subject to BACT.

- **Five (5) diesel-fired emergency generators:** The new engines result in increases of PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, and GHG emissions. The emergency generators are new units and are subject to BACT

Table I.1-1 summarizes the specific units subject to BACT and the associated pollutants emission from the unit.

3 BACT Methodology

BACT is defined as an emission limitation based on the maximum emission reduction achievable after a case-by-case review of potential emission controls which takes into account energy, environmental and economic impacts. This emissions limit may be achieved by a variety of means, such as control technologies, clean fuels, inherently lower polluting processes or alternative operating practices. A PSD permit must express a BACT determination as an enforceable emission limitation or work practice standard as defined in 40 CFR Part 52.21(b) (12).[3]

3.1 Top-Down BACT Approach

This BACT analysis has been conducted in accordance with Section 165(a) (4) of the Clean Air Act (at 40 CFR Part 52.21(j)). Proposed BACT emissions limits have been selected using the "top-down" approach specified in U.S. EPA's draft New Source Review Workshop Manual, (October 1990),[4] using the five-step process. This is outlined in Sections 3.1.1 through 3.1.5.

3.1.1 Step 1 - Identify all Available Control Technologies

All available control technologies are identified for each emission unit. A control technology is considered available for a specific pollutant if it could practically be applied to the specific emission unit. To identify all available control technologies, the following sources were consulted:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC)
- EPA draft permit review comments on recent PSD permits for GHG emissions
- State/local agency air quality permits and the associated agency review documents
- Air pollution control technology vendors
- Manufacturer's recommendations

[3] "Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

[4] The workshop manual can be found at U.S. EPA's website https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf.

Court and regulatory agency determinations[5] have held that "clean fuels" must be considered as one of the emission control technologies in a BACT analysis. The fuels analysis is based on pollutant emissions directly associated with use of a particular fuel. EPA has recognized that the initial list of control technologies for a BACT analysis does not need to include "clean fuel" technologies that would fundamentally redefine the source. Such technologies include those that would require a permit applicant to switch to a primary fuel type (i.e., coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process.

In its March 2011 guidance document "PSD and Title V Permitting Guidelines for Greenhouse Gases" [6], the EPA notes that overall energy efficiency of the source or modification should be included as one of the emission control methodologies considered in a BACT analysis. Energy efficiency measures may reduce fuel use, which in turn reduces combustion-related emissions of GHGs and other pollutants. However, energy efficiency technologies or alternative production processes that would fundamentally redefine the source do not need to be considered.

3.1.2 Step 2 - Eliminate Technically Infeasible Control Technologies

Each control technology identified in Step 1 is evaluated, using source-specific factors to determine if it is technically feasible. If physical, chemical, and engineering principles demonstrate that a technology could not be successfully used on the emission unit, then that technology is determined to be technically infeasible. Economics are not considered in the determination of technical feasibility. Technologies that are determined to be infeasible are eliminated from further consideration.

3.1.3 Step 3 – Rank Technically Feasible Control Technologies by Control Effectiveness

All technically feasible technologies are ranked in order of overall control effectiveness. Rankings are based on the level of emission control expressed as emissions per unit of production, emissions per unit of energy used, the concentration of a pollutant emitted from the source, control efficiency, or a similar measure. The control effectiveness listed will be representative of the level of emission control, which can be achieved by the control technology at the operating conditions of the emission unit being reviewed. If the most effective control technology is selected as BACT, completion of Step 4 is not required.

3.1.4 Step 4 - Evaluate Technically Feasible Control Technologies

The economic, environmental, and energy impacts of each control technology are evaluated. Step 4 is only required if the most effective control technology is not proposed as BACT.

---

[5] Northern Michigan University Ripley Heating Plant – PSD Appeal No. 08-02 before the US EPA Environmental Appeals Board and Petition Numbers IV-2008-1 and IV-2008-2 to the US EPA for re-consideration of Title V/PSD Air Quality Permit #V-07-017 for Cash Creek Generation, LLC facility located in Henderson, Kentucky.

[6] https://www.epa.gov/sites/default/files/2015-07/documents/ghgguid.pdf.

3.1.4.1 Economic Impacts

Economic impacts were analyzed using the procedures found in the EPA Air Pollution Control Cost Manual – Seventh and Sixth Editions (EPA 452/B-02-001) as applicable. If project specific cost data was not readily available, cost data from other recent comparable projects was used with adjustments for inflation and size. The source of the control equipment cost data are noted in each of the control cost analysis worksheets in Attachment I.1.

Cost effectiveness is evaluated on a dollar-per-ton ($/ton) basis using the annual operating cost ($/yr) divided by the annual emission reduction achieved by the control device (ton/yr). A control technology is considered economically infeasible if the control cost on a dollar-per-ton basis exceeds the amount that other sources in the same industrial classification have incurred. The EPA provides guidance for completing BACT economic impact analyses in the draft New Source Review Workshop Manual (October 1990). Chapter B, Section IV.D.2. states:

"Cost effectiveness (dollars per ton of pollutant reduced) values above the levels experienced by other sources of the same type and pollutant, are taken as an indication that unusual and persuasive differences exist with respect to the source under review. In addition, where the cost of a control alternative for the specific source reviewed is within the range of normal costs for that control alternative, the alternative, in certain limited circumstances, may still be eligible for elimination. To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations. If the circumstances of the differences are adequately documented and explained in the application and are acceptable to the reviewing agency they may provide a basis for eliminating the control alternative."

Unfortunately, cost effectiveness information is rarely tracked or published, even in the EPA's own clearinghouse database of BACT determinations. Typically, a screening threshold of $10,000 per ton is relied on to determine economic feasibility, unless there are special circumstances, such as areas that are in or close to non-attainment of air quality standards. Several air quality control districts in California have published cost effectiveness guidelines. However, these should be considered to be on the extreme end of what is a typical cost effectiveness threshold since these areas have ongoing and historical issues with poor air quality and non-attainment of air quality standards. In addition, the California BACT guidance allows the use of a 10-year equipment life in the calculation of annualized operating cost. This inflates the $/ton as compared to those calculated using EPA BACT guidance which typically assumes a 20-year equipment life be used in calculating the annualized operating cost. However, the $10,000/ton screening threshold is still being used as recent as April 2022 (reference (2)) for states with NAAQS attainment. Therefore, this is a reasonable starting point to screen for cost-effectiveness as the Minnesota Pollution Control Agency (MPCA) has not specifically listed cost effectiveness thresholds. Finally, it should be noted that CO cost effectiveness thresholds should be much lower than other criteria pollutants. For example, the MPCA considered $3,301/ton CO to be cost prohibitive in a previous New Source Review permit (reference (3)).

3.1.4.2 Environmental Impacts

The environmental impact analysis assesses collateral environmental impacts associated with control of the regulated pollutant in question. Impacts considered may include solid or hazardous waste generation, wastewater discharges from a control device, visibility impacts, collateral increases in emissions of other criteria or non-criteria pollutants, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

3.1.4.3 Energy Impacts

The energy impact analysis considers whether use of an emission control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use. Energy impacts may consider whether use of an emission control technology will have an adverse impact on local energy supplies due to increased fuel consumption or the loss of fuel production or power generation. Control equipment energy-use-rate estimates are noted in each of the control cost analysis worksheets in Attachment I.1.

3.1.5 Step 5 - Select BACT

Based on technical considerations and economic, environmental and energy impacts, the proposed BACT for each emissions unit will include:

- a pollutant-specific emission control technology as BACT, or a combination of controls when appropriate,
- a BACT emission limit, and
- a BACT limit compliance demonstration method.

Summary tables of relevant RBLC determinations used in establishing proposed BACT limitations are provided in Attachment I.2.

A summary of the BACT limits in this report are provided in Table I.1-2 through Table I.1-4.

3.2 Form of BACT Emission Limits

A PSD permit must express the BACT determination as an enforceable permit limitation unless it is infeasible to do so (40 C.F.R. § 52.21(b) (12)). Proposed BACT emission limits are expressed as a standard of performance (i.e., gr/dscf) and a mass emission rate (i.e., lb/hr) (or equivalent measure) when appropriate. The standard of performance will be expressed as emissions per unit of production, the concentration of a pollutant emitted from the source, or a similar measure that represents the level of control achieved by the control technology. The mass emission limit will be set at the emission unit's potential to emit on a basis consistent with the test method or regulatory compliance requirements. This provides the source flexibility in maintaining compliance while keeping the averaging time short enough to be practicably enforceable. If a mass emission limit is not practical, a production limit or similar measure, which is practicably enforceable, will be proposed.

3.3 Constraints on BACT Emission Limits

BACT emission limits for sources subject to New Source Performance Standards ([NSPS] 40 CFR Part 60) or National Emission Standards for Hazardous Air Pollutants ([NESHAPS] 40 CFR Part 61) cannot be less stringent than the applicable standards. In other words, applicable 40 CFR Part 60 NSPS or 40 CFR Part 61 NESHAPS standards provide a "floor" for BACT emission limits.

A review of NSPS and NESHAP standards indicates that the following standards under Part 60 and 61 are applicable to the Projects:

Table I.3-1 NSPS and NESHAPS Establishing BACT "Floor"

NSPS or NESHAPS Regulation	Affected Source Type	PSD Pollutants Regulated
NSPS GG	Stationary Combustion Turbines	NO_X
NSPS IIII	Stationary Compression Ignition Internal Combustion Engines	PM, NO_X, CO, VOC

Minn. Rev. Chapter 7011 incorporates by reference the Federal New Source Performance Standards (NSPS) promulgated at 40 CFR Part 60. An NSPS is applicable to certain categories of affected facilities that are constructed, modified, or reconstructed and that meet other applicability criteria on or after a compliance date upon which a relevant subpart applies.

The combustion turbines are subject to NSPS GG – Standards of Performance for Stationary Combustion Turbines.

The engine generators and emergency generators are subject to NSPS IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

Maximum Achievable Control Technology (MACT) standards issued under 40 CFR Part 63 can also add additional applicable emission limits. It is important to note that the facility is an Area Source, not a Major Source, of HAP. The MACT for Stationary Combustion Turbines (40 CFR Part 63 Subpart YYYY) only applies to sources located at Major Sources of HAP and therefore is not applicable to this facility. The MACT for Stationary Reciprocating Internal Combustion Engines (40 CFR Part 63 Subpart ZZZZ) will apply to the new engines, but the affected facility complies with the MACT standard by complying with the NSPS and, therefore, no MACT requirements that limit PSD pollutants as surrogates for control of HAP emissions need to be considered in the BACT analysis.

3.4 Compliance with BACT Emission Limits during Startup, Shutdown and Malfunction (SSM) Situations

Startups and shutdowns are infrequent events associated with maintenance of the facility. Typically, operating equipment is taken out of service periodically for inspection, repair, and/or preventative maintenance. Other planned startup and shutdown events may be necessary to repair equipment, which

cannot be fixed while the unit is operating. Shutdowns may also occur due to unplanned equipment failures (malfunctions). Routine maintenance inspections are designed to minimize the number of shutdowns caused due to malfunctions and minimize other maintenance during the remainder of the year.

Temperatures, pressures and flows in process equipment can vary significantly during periods of startup, shutdown, and malfunction. Following good combustion practices and/or good operating practices during startup, shutdown, or malfunction conditions will minimize both the extent and duration of excess emissions. However, compliance with BACT limitations cannot always be achieved at all times during startup, shutdown and malfunction conditions. In those cases where compliance with the proposed BACT limitations are not feasible during periods of startup and shutdown, BACT limitations for startup and/or shutdown conditions are specified.

4 BACT for the Combustion Turbines

The combustion turbines are a simple cycle design for electricity generation. Emissions are the result of natural gas combustion.

4.1 Combustion Turbines PM, PM_{10}, $PM_{2.5}$ Emissions

PM, PM_{10} and $PM_{2.5}$ will be emitted in trace quantities from the combustion turbine as a result of any incomplete combustion, PM present in the combustion air, and solid and condensable materials contained in the gaseous fuel. All PM from gaseous fuel firing is considered fine particulate less than 1 micron in diameter. Therefore, PM_{10} may be considered equivalent to $PM_{2.5}$ (filterable + condensable), and PM (filterable) may be considered equivalent to the filterable fractions of PM_{10} and $PM_{2.5}$.

4.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling PM, PM_{10}, and $PM_{2.5}$ emissions are summarized in Table I.4-1.

Table I.4-1 Available PM, PM_{10}, $PM_{2.5}$, Emission Control Technologies for the Combustion Turbines

Technology	Description
Clean Fuels	For combustion sources, the use of clean fuels must be considered as specified in the definition of BACT. The gas turbine only burns natural gas. Combustion of natural gas has the lowest particulate emission rate of available fuels. This review assumes that clean fuels will be used in all cases evaluated for the selection of BACT emission controls from the following remaining control devices evaluated.
Good Combustion Practices	Good combustion practices consist of proper unit operation and maintenance in according with engineering practices and manufacturer specifications.
Add-on Particulate Controls	Add-on controls include baghouses, electrostatic precipitators, and wet scrubbers.

4.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the potential control technologies is summarized in Table I.4-2.

Table I.4-2 Technical Feasibility of PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Combustion Turbines

Technology	Technically Feasible?
Clean Fuels	Yes
Good Combustion Practices	Yes
Add-on Particulate Controls	No

The use of add-on control technologies, such as a baghouse, electrostatic precipitator, or wet scrubber, can provide PM control for solid and liquid fuel-combustion applications by removing filterable PM. However, these add-on control technologies are not technically feasible for natural gas post-combustion emissions due to the capture limitations of these control technologies and the very low PM concentration levels.

No add-on control technologies were listed in the RBLC database (Attachment I.2-1) to control PM emissions from natural gas-fired turbines. All listed projects specify clean fuels and/or good combustion practices. Therefore, add-on controls are not technically feasible for the combustion turbines.

4.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The effectiveness ranking of PM, PM_{10}, $PM_{2.5}$ emission controls for the combustion turbines are summarized in Table I.4-3.

Table I.4-3 Ranking of Remaining PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Combustion Turbines

Rank	Technology	Estimated Control Efficiency
N/A	Clean Fuels	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

4.1.4 Step 4 – Evaluation of Feasible Control Technologies

Xcel has selected the only technically feasible options, and thus the top ranked, control technologies for the combustion turbines. There are no adverse energy, environmental, or economic impacts associated with implementing good combustion practices or with the use of clean fuels.

4.1.5 Step 5 – BACT Selection

Adherence to good combustion practices and the use of natural gas as a clean fuel are selected as BACT for controlling PM emissions from the combustion turbines. Use of natural gas as a clean fuel minimizes the amount of combustion-related particulates emitted. Good combustion practices are preventative measures that minimize the release of pollutants into the environment and reduce the amount of fuel burned.

This determination is consistent with previous BACT determinations, as demonstrated by the list of determinations in the RBLC database (Attachment I.2-1). The manufacturer's recommended operating and maintenance procedures and/or industry best practices will be followed to ensure that good combustion practices are used and to minimize emissions during both normal operation and during startup and shutdown. Ambient air utilized for combustion air in the combustion turbines may contain PM, which could damage the turbines. Based on good design practices, the combustion turbines are equipped with combustion air filters to protect the combustion turbines. These filters will also reduce filterable particulate present in the exhaust attributable to particulates in the combustion air.

BACT limits are summarized in Table I.4-4. However, it is important to note that a significant portion of PM emissions from the combustion turbines is the result of ambient air and fuel quality, which are inherently variable. There are no reasonable methods that an operator can employ to adjust operations to account for this inherent variability. Second, due to the very low emission rate and exhaust concentration resulting from natural gas combustion, PM measurement methods can have a significant impact on measured PM emission rates (reference (4)). Inadequate blank corrections and artifact PM formation result in positive biases, producing higher and more variable test results.

Table I.4-4 Proposed BACT PM, PM_{10}, $PM_{2.5}$ Limits for the Combustion Turbines

Combustion Turbines	PM lb/MMBtu	PM_{10} lb/MMBtu	$PM_{2.5}$ lb/MMBtu
	0.0066	0.0066	0.0066
	PM lb/hr	PM_{10} lb/hr	$PM_{2.5}$ lb/hr
All operating scenarios	13.48	13.48	13.48
Compliance Demonstration	Initial Performance Test EPA Method 5 and EPA Method 202 followed by reoccurring tests every five years after, combust only natural gas, good combustion practices. Emissions during startup, shutdown, or emergencies are not expected to change from normal operations.		

4.2 Combustion Turbines NO_X Emissions

Fuel combustion in the combustion turbines is the primary source of NO_X emissions.

4.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for the combustion turbines' NO_X emissions are summarized in Table I.4-5.

Table I.4-5 Available NO_X Emission Control Technologies for the Combustion Turbines

Technology	Description
Clean Fuels	See Section 4.1.1 for a description of clean fuels.
Good Combustion Practices	See Section 4.1.1 for a description of good combustion practices.
Dry Low NO_X Burners (DLNB)	Dry low NO_X burners are designed to reduce NO_X emissions by reducing flame temperatures in the turbines combustor system. Typically, this is done by staging either the combustion air or fuel injection rates into the turbine combustor. Dry Low NO_X burners currently are the most common type of NO_X control used on combustion turbines.
Selective Non-Catalytic Reduction (SNCR)	Selective non-catalytic reduction reduces NO_X emissions with ammonia or urea injection into a heater or boiler firebox. A temperature range of 1,600° F to 2,100° F is required. At these temperatures, the ammonia and NO_X react to form N_2 and water. If urea is used, it will break down into ammonia after it is injected, and then the ammonia reacts with the NO_X.
Selective Catalytic Reduction (SCR)	Selective catalytic reduction reduces NO_X emissions with ammonia or urea injection in the presence of a catalyst. The catalyst enables the de-NO_X reactions to proceed at a lower temperature than SNCR. Most SCR catalysts must be at temperatures of 600° F to 800° F to work, but higher temperature applications for simple-cycle turbines are available in the 850° F to 1,000° F range.
Water or Steam Injection	Water or steam injection introduces water into the combustion chamber, which absorbs heat and subsequently reduces flame temperature. The decrease in flame temperature results in lower levels of NO_X formation.
XONON™	XONON™ is a low NO_X gas turbine combustion technology developed by Catalytic Energy Systems. Reduced NO_X emissions are achieved by using a catalyst to oxidize the turbine fuel. The lower operating temperature reduces thermal NO_X formation.
EM_X (formerly SCO NO_X)	EM_X is an add-on control technology that uses a single catalyst to reduce NO_X, CO, and VOC emissions without any reagents such as ammonia. NO_X is catalytically oxidized to NO_2 and then the NO_2 is absorbed onto the EM_X catalyst which is coated with potassium carbonate (K_2CO_3). Periodically, the catalyst is regenerated using hot hydrogen (1,900° F). NO_2 is reduced to nitrogen gas (N_2) and the K_2CO_3 is reactivated during regeneration. A separate process is used to generate the H_2 from natural gas.
Non-Selective Catalytic Reduction (NSCR)	NSCR is a control method, which utilizes a three-way catalyst to simultaneously control NO_X, CO and VOC emissions. CO and unburned hydrocarbons are used as the reducing agents for converting NO_X to N_2 and water. NSCR catalysts require low oxygen concentrations (< 0.5% O_2) and an operating temperature range of 700° F to 1,200° F. Due to these restrictions, NSCR is typically used for controlling emissions from rich burn internal combustion engines.

4.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for NO_X emissions are summarized in Table I.4-6.

Table I.4-6 Technical Feasibility of NO_X Emission Control Technologies for the Combustion Turbines

Technology	Technically Feasible?
Clean Fuels	Yes
Good Combustion Practices	Yes
Dry Low NO_X Burners (DLNB)	Yes
Selective Non-Catalytic Reduction (SNCR)	No
Selective Catalytic Reduction (SCR)	Yes
Water Injection	Yes
XONON™	No
EM_X (formerly $SCONO_X$)	No
Non-Selective Catalytic Reduction (NSCR)	No

4.2.2.1 SNCR

SNCR is not technically feasible because the exhaust temperature of the turbines is less than the temperature required for this control technology to operate. In addition, there were no RBLC determinations for turbines of this size that used this as a control technology, which indicates that SNCR has not been demonstrated in practice and is inferior to the proposed BACT controls. Further, SNCR controls are not effective when NO_X levels are less than 200 ppm (reference (5)). NO_X levels exiting the combustion turbines are expected to be significantly lower.

4.2.2.2 XONON™

XONON™ is not technically feasible because it has not been commercially demonstrated on large combustion turbines comparable to those at the Blue Lake facility (174 MW). XONON™ is only available on Kawasaki turbine generator sizes from 1.5 MWe to 18 MWe. In addition, the RBLC did not return any XONON™ determinations for turbines of similar size. Therefore, the lack of any recent determinations indicates that this technology has not been demonstrated in practice for turbines of this size.

4.2.2.3 EM_X (formerly $SCONO_X$)

The required operating temperature range is between 300° F and 700 °F, which is too cold for the Blue Lake combustion turbines with exhaust temperatures of 1,105° F. Therefore, substantial gas cooling would be required. Further, $SCONO_X$ costs much more than SCR, is mechanically complicated, and requires on-site hydrogen production from natural gas. In addition, there were no $SCONO_X$ RBLC determinations for simple cycle turbines of similar size. The lack of determinations indicates that this technology has not been sufficiently demonstrated in practice. Therefore, this technology is not technically feasible.

4.2.2.4 NSCR

NSCR is not feasible in the combustion turbines because the exhaust O_2 concentration is approximately 14%. NSCR catalysts require low oxygen concentrations (< 0.5% O2) for the catalyst to function. Therefore, this technology is not technically feasible.

4.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.4-7 according to their control effectiveness.

Table I.4-7 Ranking of Remaining NO_X Emission Control Technologies for the Combustion Turbines

Rank	Technology	Estimated Emissions Performance[1]
1	SCR	2 ppm
2	Dry Low NO_X Burners (DLNB)	11 ppm
3	Water Injection	Unknown, but inferior to SCR or DLNB
N/A	Clean Fuels	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

[1] Emissions performance (ppm) is corrected to 15% O2.

4.2.4 Step 4 – Evaluation of Feasible Control Technologies

SCR achieves better levels of control than a DLNB. To evaluate the economic feasibility of SCR, control costs were calculated using the procedures found in the EPA Air Pollution Control Cost Manual for SCR (reference (6)). However, the procedures to estimate capital costs in the EPA Air Pollution Control Cost Manual do not apply to combustion turbines. Therefore, Xcel estimated capital costs in two different ways using 1) a total installed cost based on a third-party engineering consultant, and 2) a vendor supplied purchased equipment cost for an SCR system where installation costs we estimated using factors in reference (7). Calculated equipment costs were then adjusted for inflation. Using both costing approaches, Xcel presented a range of cost-effectiveness. Further, the exhaust temperature of the combustion turbines is too hot to accommodate SCR. Therefore, Xcel accounted for tempering air to cool the exhaust to acceptable SCR catalyst temperatures and a tempering air fan. The details regarding the economic feasibility of SCR for the combustion turbines are summarized in Table I.4-8. A single cost evaluation was conducted for one gas turbine because the two are the same.

Table I.4-8 Cost Effectiveness of NO_X Emission Control Technologies for the Combustion Turbines

Technology	Cost Effectiveness ($/ton)	Economically Feasible?
SCR	$27,400 - $34,300	No

The cost effectiveness of SCR is excessive and is not economically feasible. DLNB costs were not evaluated because it is inherent to existing gas turbine design.

4.2.4.1 Environmental Impacts

Environmental impacts of technically feasible control options are summarized in Table I.4-9.

Table I.4-9 Environmental Impacts of NO_X Control Technologies for the Combustion Turbines

Technology	Collateral Air Emissions	Non-Air Environmental Impacts
SCR	Ammonia slip, PM	Spent catalyst solid waste
DLNB	NA	NA
Water Injection	May form more CO/VOC	NA
Clean Fuels	NA	NA
Good Combustion Practices	NA	NA

4.2.4.2 Energy Impacts

Energy impacts of technically feasible control options are summarized in Table I.4-10.

Table I.4-10 Energy Impacts of NO_X Control Technologies for the Combustion Turbines

Technology	Energy Impacts
SCR	Reagent vaporization energy
DLNB	N/A
Water Injection	Increased fuel usage to vaporize water
Clean Fuels	N/A
Good Combustion Practices	N/A

4.2.5 Step 5 – BACT Selection

The use of a DLNB that is inherent to the combustion turbines, clean fuels (natural gas), and good combustion practices have all been selected as NO_X BACT. Good combustion practices consist of proper burner operation and maintenance. SCR is cost prohibitive and there are no demonstrations of water injection with DLNB on similar turbines that can achieve lower emissions than DLNB alone.

The proposed BACT performance limit is similar to other SCR RBLC determinations (Attachment I.2-1) for DLNB. Note, the proposed limit is slightly higher than the most common DLNB RBLC determinations at 9 ppm. This is based on observed emission rates at the facility as the 9 ppm determinations better correspond to newer versions of the GE 7F turbines. In addition, the turbines will continue to comply with NSPS GG. The proposed BACT limits and compliance demonstrations are summarized in Table I.4-11.

Table I.4-11 Proposed BACT NO_X Limitations for the Combustion Turbines

Category	Demonstration
Limitations	NO_X emissions are limited to 11 ppm (dry basis) corrected to 15% O_2 and 73.51 lb/hr on a 24-hr rolling average during normal operation.
	NO_X emissions for startup/shutdown and emergency operation are limited to 14.05 ton/yr. Startup of the GE 7FA turbine is complete and normal operation commences upon initial attainment of Mode 6 operation as indicated by the combustion turbine control system. Shutdown commences and normal operation ceases upon cessation of Mode 6 operation as turbine load decreases during shutdown. Mode 6 operation occurs when all burner nozzles are firing in low-NO_X configuration.
Compliance Demonstration – Normal Operations	NO_X Continuous Emission Monitoring System (CEMS)
Compliance Demonstration – Startup, Shutdown, and Emergency Operation	Good combustion practices

4.3 Combustion Turbines CO and VOC Emissions

Incomplete fuel combustion is the primary source of CO and VOC emissions.

4.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies for CO and VOC emissions are described in Table I.4-12.

Table I.4-12 Available CO and VOC Emission Control Technologies for the Combustion Turbines

Technology	Description
Good Combustion Practices	See Section 4.1.1 for a description of good combustion practices.
Oxidation Catalyst	Oxidation catalysts are post-combustion, add-on emission controls. The exhaust is routed through a bed of catalyst, which promotes the oxidation of CO/VOC to carbon dioxide and water.
Non-Selective Catalytic Reduction (NSCR)	Refer to Section 4.2.1 for a description of NSCR
$SCONO_X$	Refer to Section 4.2.1 for a description of NSCR

4.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of potential control options for CO and VOC emissions are summarized in Table I.4-13.

Table I.4-13 Technical Feasibility of CO and VOC Control Technologies for the Combustion Turbines

Technology	Technically Feasible?
Good Combustion Practices	Yes
Oxidation Catalyst	Yes
$SCONO_X$	No
NSCR	No

4.3.2.1 EM_X (formerly $SCONO_X$)

$SCONO_X$ is not technically feasible as described in Section 4.2.2.3.

4.3.2.2 NSCR

NSCR is not technically feasible as described in Section 4.2.2.4.

4.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.4-14 according to their control effectiveness.

Table I.4-14 Ranking of Remaining CO/VOC Emission Control Technologies for the Combustion Turbines

Rank	Technology	Estimated Emissions Performance[1]
1	Oxidation Catalyst	CO: 3 ppm; VOC: 1.5 ppm
N/A	Good Combustion Practices	Inherently lower emissions

[1] Emission control efficiency (ppm) is corrected to 15% O2.

4.3.4 Step 4 – Evaluation of Feasible Control Technologies

An oxidation catalyst is the only superior control technology remaining besides good combustion practices. Therefore, Xcel evaluated the control costs for an oxidation catalyst on the combustion turbines. Catalyst capital equipment and catalyst replacement costs were based on the most recent PSD approved BACT report containing an economic analysis of oxidation catalyst and adjusted from 2017 dollars to 2022 dollars the Chemical Engineering Plant Cost Index (reference (20)). Although the EPA suggests limiting scaling to 5 years, the data from the approved BACT was the most recent information available. Additionally, the primary costs associated with the oxidation catalyst are based on the metals used in the catalyst, and these metals have outpaced the general inflation rates. Therefore, the costs used in the analysis are conservative. Details can be found in Attachment I.1-1. Table I.4-15 summarizes the results.

Table I.4-15 Cost Effectiveness of CO/VOC Emission Control Technologies for the Combustion Turbines

Technology	Cost Effectiveness ($/ton)	Economically Feasible?
Oxidation Catalyst	CO - $10,519 VOC - $26,837	No

The cost effectiveness of an oxidation catalyst is not economically feasible.

There are no adverse energy or non-air impacts associated with use of good combustion practices. Use of oxidation catalyst will generate spent catalyst waste, and the oxidation catalyst will oxidize some SO_2 to sulfuric acid mist.

4.3.5 Step 5 – BACT Selection

Good combustion practices have been selected as CO/VOC BACT for the combustion turbines. Good combustion practices consist of proper turbine operation and maintenance in accordance with engineering practices.

The proposed performance limit is comparable to other RBLC determinations (Attachment I.2-1) for CO and VOC. Proposed BACT limits and compliance demonstrations are summarized in Table I.4-16.

Table I.4-16 Proposed BACT CO and VOC Limitations for the Combustion Turbines

Category	Demonstration
Limitations	CO emissions are limited to 9 ppm (dry basis) corrected to 15% O_2 and 38.80 lb/hr on a 24-hr rolling average during normal operation. VOC (as methane) emissions are limited to 4.6 ppm (dry basis) at actual O_2 and 10.03 lb/hr on a 3-hr basis. CO and VOC (as methane) emissions for startup/shutdown and emergency operation are limited to 24.70 and 33.60 ton/yr respectively. Startup of the GE 7FA turbine is complete and normal operation commences upon initial attainment of Mode 6 operation as indicated by the combustion turbine control system. Shutdown commences and normal operation ceases upon cessation of Mode 6 operation as turbine load decreases during shutdown. Mode 6 operation occurs when all burner nozzles are firing in low-NO_X configuration.
Compliance Demonstration – Normal Operations	CO CEMS for normal operations. Xcel proposes to conduct an initial Method 25A performance test (average of three one-hour test runs) to demonstrate compliance with VOC. Assuming the initial test passes, Xcel proposes to use compliance with CO limits via CEMS as a surrogate for VOC after the initial performance test.
Compliance Demonstration – Startup, Shutdown, and Emergency Operation	Good combustion practices

4.4 Combustion Turbines GHG Emissions

The GHG BACT analysis for the combustion turbines is included in Section 7.

5 BACT for the Dual Fuel Engine Generators

Xcel proposes to install three non-emergency dual fuel reciprocating internal combustion engine generators. Each generator will have an electrical output of 9.37 MW.

5.1 Engine Generators PM/PM_{10}/$PM_{2.5}$ Emissions

Particulate matter emissions from engines are the result of incomplete combustion. PM emissions include only solid particulates. PM_{10} and $PM_{2.5}$ emissions include part solid particulates in the $PM_{2.5}$ and PM_{10} size ranges and condensable particulate matter. Condensable particulate matter consists primarily of organic compounds which are in a vapor state in the engine exhaust and condense to liquid droplets in the atmosphere. Condensable particulates also contains condensable inorganic compounds such as sulfates formed from oxidation of fuel bound sulfur. All condensable particulates are less than 2.5 microns in diameter.

5.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling PM, PM_{10}, and $PM_{2.5}$ emissions are summarized in Table I.5-1.

Table I.5-1 Available PM, PM_{10}, $PM_{2.5}$, Emission Control Technologies for the Engine Generators

Technology	Description
Primary use of Pipeline Natural Gas with ULSD pilot	Use of pipeline natural gas will lower PM emissions when compared to 100% use of ULSD.
Use of Ultra-low Sulfur Diesel (ULSD)	Use of ULSD fuel will limit the formation of sulfates from oxidation of fuel bound sulfur.
Compliance with NSPS IIII	Technologies utilized to meet NSPS IIII standards may include advanced injection systems and combustion techniques. Use of these controls can vary by engine manufacturer.
Good Combustion Practices	Operate engines in accordance with manufacturer specifications
Diesel Particulate Filter (DPF)	Add-on DPFs capture filterable PM from engine exhaust. Regeneration of the filter can require an electrical heating element or fuel burner to oxidize particulate build up.
Oxidation Catalyst	Add-on oxidation catalysts are typically used to control CO/VOC, but small portions of PM can be controlled with this technology

5.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the potential control technologies is summarized in Table I.5-2.

Table I.5-2 Technical Feasibility of PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Engine Generators

Technology	Technically Feasible?
Primary use of Pipeline Natural Gas with ULSD pilot	Yes
Use of ULSD	Yes
Emergency Use Classification	No
Compliance with NSPS IIII	Yes
Good Combustion Practices	Yes
Diesel Particulate Filter (DPF)	No
Oxidation Catalyst	Yes

Emergency use classification is not technically feasible because the engines will be operated too frequently to be considered as emergency use only.

Use of a DPF is primarily used in vehicles and small non-road engines and are not compatible with the Wartsila 9.37 MW engines (Attachment I.3). The EPA's Verified Technologies for Clean Diesel for use in retrofit engines does include DPFs from various vendors (reference (21)). However, the maximum rating for non-road engines in the list is 0.45 MW. The California Air Resource Board (CARB) also provides manufacturer information for DPFs verified for use on certain engines, including engines greater than 750 hp on their verified technologies list (reference (22)). The CARB includes the operating criteria required by each manufacturer, as well as a list of approved engine families for each manufacturer. Not only are the proposed engines not included in the approved engine list, but they are also operationally different from the allowable engines. One primary difference is most of the manufacturers require certified off-road engines (Tier 1, Tier 2, etc.), while the proposed units are not certified. The certified engines are primarily high-speed engines that have a higher exhaust temperature. The proposed units are medium-speed engines and will have lower exhaust temperature. Many of the CARB listed DPFs also require active regeneration with a minimum temperature that must be achieved over a certain length of time and/or require the unit to run within a temperature range for a certain percentage of engine run time. The proposed units are not capable of meeting any of the manufacturer's requirements when it comes to exhaust temperature ranges and durations. Therefore, the DPFs included in the EPA's Verified Technologies and CARB verified technologies list cannot be used on the proposed units. Additionally, no engines of similar size were identified as using DPFs in the RBLC database. Therefore, DPF is not technically feasible.

5.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.5-3 according to their control effectiveness.

Table I.5-3 Ranking of Remaining PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Engine Generators

Rank	Technology	Estimated Control Efficiency
1	Compliance with NSPS IIII	60%
2	Oxidation Catalyst	30%
N/A	Primary use of pipeline natural gas with ULSD pilot	Inherently lower emissions
N/A	Use of ULSD	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

5.1.4 Step 4 – Evaluation of Feasible Control Technologies

Xcel has selected the top performing technically feasible control technologies so no economic, energy, or environmental impacts analysis is needed.

5.1.5 Step 5 – BACT Selection

Xcel selects the use of primarily pipeline natural gas, with ULSD as an option, compliance with NSPS IIII requirements, good combustion practices, and an oxidation catalyst as BACT for the engine generators. DPFs are not economically feasible. BACT limits are summarized in Table I.5-4 and are among the top-performing engines in the RBLC database. Refer to Attachment I.2-2 for more detail.

Table I.5-4 Proposed PM, PM_{10}, $PM_{2.5}$ BACT Limits for the Engine Generators

Performance Limits (Normal Operations Only)			
Performance Limitation - 75% Load	PM (filterable) g/kW-hr	PM_{10} g/kWhe	$PM_{2.5}$ g/kWhe
	0.15 (NSPS limit)	DF – 0.10 Diesel – 0.22	DF – 0.10 Diesel – 0.22
Performance Limitation - < 75% Load	N/A – NSPS limit is for near maximum load	DF – 0.16 Diesel – 0.32	DF – 0.16 Diesel – 0.32
Mass Emission Limitation	**PM lb/hr**	**PM_{10} lb/hr**	**$PM_{2.5}$ lb/hr**
Single Engine – Normal Operations	DF – 2.01 Diesel – 4.76	DF – 2.01 Diesel – 4.76	DF – 2.01 Diesel – 4.76
Single Engine – Startup, Shutdown, and Emergency Operations	2.01 ton/yr	2.01 ton/yr	2.01 ton/yr
Compliance Demonstrations			
Normal Operations	$PM_{10}/PM_{2.5}$ - Initial Performance Test Method 5 and Method 202 while combusting diesel (worst-case), average of three 1-hour test runs after shakedown followed by reoccurring tests every five years after, operate engine in accordance with manufacturer specifications, maintain records of fuel use. PM (filterable) – Method 5 testing must be conducted annually per 40 CFR 60.4211(d)(3) AND must be within 10% of peak load per 40 CFR 60.4213(a)		
Startup, Shutdown, and Emergency Operations	Good combustion practices. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the engine temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits. Shutdown begins when the operator initiates the shutdown of the engine and ends when fuel is no longer being introduced into the engine.		

5.2 Engine Generators NO_X Emissions

NO_X emissions are formed during combustion of fuel. The NO_X is formed from oxidation of nitrogen in the combustion air and oxidation of fuel bound nitrogen.

5.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling NO_X emissions are summarized in Table I.5-5.

Table I.5-5 Available NO_X Emission Control Technologies for the Engine Generators

Technology	Description
Primary use of Pipeline Natural Gas with ULSD pilot	Use of pipeline natural gas will lower NO_X emissions when compared to 100% use of ULSD.
Use of Ultra-low Sulfur Diesel (ULSD)	Use of ULSD fuel will limit the formation of fuel bound NO_X emissions. Much of the fuel bound nitrogen is removed during the desulfurization process.
Good Combustion Practices	Refer to Section 4.1.1 for a description
Selective Non-Catalytic Reduction (SNCR)	Refer to Section 4.2.1 for a description
Selective Catalytic Reduction (SCR)	Refer to Section 4.2.1 for a description
Non-Selective Catalytic Reduction (NSCR)	See Section 4.2.1 for a description

5.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the potential control technologies is summarized in Table I.5-6.

Table I.5-6 Technical Feasibility of NO_X Emission Control Technologies for the Engine Generators

Technology	Technically Feasible?
Primary use of Pipeline Natural Gas with ULSD pilot	Yes
Use of Ultra-low Sulfur Diesel (ULSD)	Yes
Good Combustion Practices	Yes
Selective Non-Catalytic Reduction (SNCR)	No
Selective Catalytic Reduction (SCR)	Yes
Non-Selective Catalytic Reduction (NSCR)	No

5.2.2.1 SNCR

SNCR is not feasible because engine temperatures do not meet the SNCR reaction temperature range of 1,600° F to 2,000° F. Engine exhaust temperatures are below 1,000° F.

5.2.2.2 NSCR

NSCR is not feasible in the engine generators because diesel engines operate with lean-burn air to fuel ratios. NSCR requires rich air to fuel combustion ratios to generate CO concentrations needed for the

NSCR catalyst to function. Rich burn engines operate with O_2 levels at 1% or less. Diesel compression ignition engines operate at O_2 levels higher than 1% (reference (8)).

5.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.5-7 according to their control effectiveness.

Table I.5-7 Ranking of Remaining NO_X Emission Control Technologies for the Engine Generators

Rank	Technology	Estimated Control Efficiency
1	SCR	90%
N/A	Primary use of Pipeline Natural Gas with ULSD pilot	Inherently lower emissions
N/A	Use of ULSD	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

5.2.4 Step 4 – Evaluation of Feasible Control Technologies

Xcel has selected the top performing technically feasible control technologies so no economic, energy, or environmental impacts analysis is needed.

5.2.5 Step 5 – BACT Selection

Xcel selects SCR, the use of primarily pipeline natural gas, with ULSD as an option, and good combustion practices as BACT for the engine generators. This is consistent with the top-performing determinations in the RBLC database. Refer to Attachment I.2-2 for more detail. Proposed BACT limits are summarized in Table I.5-8.

Table I.5-8 Proposed BACT NO_x Limitations for the Engine Generators

Performance Limits g/kWhe (Normal Operations Only)	
Performance Limitation - 75% Load	DF – 0.09 g/kWhe Diesel – 0.53 g/kWhe
Performance Limitation - < 75% Load	DF – 0.15 g/kWhe Diesel – 0.66 g/kWhe
Mass Limits	
Single Engine – Normal Operations	DF – 1.65 lb/hr Diesel – 10.86 lb/hr
Single Engine – Startup, Shutdown, and Emergency Operations	17.98 ton/yr
Compliance Demonstration	
Normal Operations	Performance Test Method 7E must be conducted annually per 40 CFR 60.4211(d)(3) AND must be within 10% of peak load per 40 CFR 60.4213(a), average of three 1-hour test runs, operate engine in accordance with manufacturer specifications, operate SCR equipment in accordance with manufacturer specifications except during startup and shutdown.
Startup, Shutdown, and Emergency Operations	Good combustion practices. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the catalyst temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits. Shutdown begins when the operator initiates the shutdown of the engine and ends when fuel is no longer being introduced into the engine.

5.3 Engine Generators CO/VOC Emissions

CO and VOC emissions are formed as a result of incomplete combustion. Controlling CO and VOC emissions will also limit emissions of organic HAPs.

5.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling CO/VOC emissions are summarized in Table I.5-9.

Table I.5-9 Available CO/VOC Emission Control Technologies for the Engine Generators

Technology	Description
Primary use of Pipeline Natural Gas with ULSD pilot	Use of pipeline natural gas will lower CO/VOC emissions when compared to 100% use of ULSD.
Good Combustion Practices	Refer to Section 5.1.1 for a description of this technology
Oxidation Catalyst	Refer to Section 5.1.1 for a description of this technology
Non-Selective Catalytic Reduction (NSCR)	See Section 4.2.1 for a description

5.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the potential control technologies is summarized in Table I.5-10.

Table I.5-10 Technical Feasibility of CO/VOC Emission Control Technologies for the Engine Generators

Technology	Technically Feasible?
Primary use of Pipeline Natural Gas with ULSD pilot	Yes
Good Combustion Practices	Yes
Oxidation Catalyst	Yes
Non-Selective Catalytic Reduction (NSCR)	No

5.3.2.1 NSCR

As discussed in Section 5.2.2.2, NSCR is not feasible for the proposed emergency engines.

5.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.5-11 according to their control effectiveness.

Table I.5-11 Ranking of Remaining CO/VOC Emission Control Technologies for the Engine Generators

Rank	Technology	Estimated Control Efficiency
1	Oxidation Catalyst	90%
N/A	Primary use of Pipeline Natural Gas with ULSD pilot	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

5.3.4 Step 4 – Evaluation of Feasible Control Technologies

Xcel has selected the top performing technically feasible control technologies so no economic, energy, or environmental impacts analysis is needed.

5.3.5 Step 5 – BACT Selection

Xcel selects an oxidation catalyst, the use of primarily pipeline natural gas, with ULSD as an option, and good combustion practices as BACT for the engine generators. This is similar to the best performance RBLC determinations. Refer to Attachment I.2-2 for more detail. BACT limits are summarized in Table I.5-12.

Table I.5-12 Proposed BACT CO/VOC Limitations for the Engine Generators

Performance Limits g/kWhe (Normal Operations Only)	
Performance Limitation - 75% Load	DF – 0.13 g/kWhe CO, 0.17 g/kWhe VOC as methane Diesel – 0.19 g/kWhe CO, 0.23 g/kWhe VOC as methane
Performance Limitation - < 75% Load	DF – 0.15 g/kWhe CO, 0.30 g/kWhe VOC as methane Diesel – 0.20 g/kWhe CO, 0.23 g/kWhe VOC as methane
Mass Limits	
Single Engine – Normal Operations	DF – 2.51 lb/hr CO, 3.26 lb/hr VOC as methane Diesel – 3.78 lb/hr CO, 4.33 lb/hr VOC as methane
Single Engine – Startup, Shutdown, and Emergency Operations	CO – 4.21 ton/yr VOC as methane - 1.32 ton/yr
Compliance Demonstration	
Normal Operations	Initial Performance Test Method 25A, average of three 1-hour test runs after shakedown followed by reoccurring tests every five years after, operate engine and oxidation catalyst system in accordance with manufacturer specifications.
Startup, Shutdown, and Emergency Operations	Good combustion practices. Startup begins when fuel is introduced to the generator engine and lasts for a period of up to 30 minutes or until the catalyst temperature reaches the target operating temperature specified by the manufacturer that is needed to comply with normal operating limits. Shutdown begins when the operator initiates the shutdown of the engine and ends when fuel is no longer being introduced into the engine.

6 BACT for Emergency Diesel Engine Generators

Xcel proposes to install five emergency diesel internal combustion engines to restart power plant equipment and provide power during unforeseen circumstances or shutdowns. This includes three 750 kW and two 550 kW generators.

6.1 Emergency Diesel Engine Generators $PM/PM_{10}/PM_{2.5}$ Emissions

Particulate matter emissions from diesel engines are the result of incomplete combustion. PM emissions include only solid particulates. PM_{10} and $PM_{2.5}$ emissions include part solid particulates in the $PM_{2.5}$ and PM_{10} size ranges and condensable particulate matter. Condensable particulate matter consists primarily of organic compounds which are in a vapor state in the engine exhaust and condense to liquid droplets in the atmosphere. Condensable particulates also contains condensable inorganic compounds such as sulfates formed from oxidation of fuel bound sulfur. All condensable particulates are less than 2.5 microns in diameter.

6.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling PM, PM_{10}, and $PM_{2.5}$ emissions are summarized in Table I.6-1.

Table I.6-1 Available PM, PM_{10}, $PM_{2.5}$, Emission Control Technologies for the Emergency Diesel Engine Generators

Technology	Description
Use of Ultra-low Sulfur Diesel (ULSD)	Refer to Section 5.1.1 for a description of this technology
Emergency Use Classification	Acceptance of restrictions for annual operating hours greatly reduces potential PM emissions
Compliance with NSPS IIII	Refer to Section 5.1.1 for a description of this technology
Good Combustion Practices	Refer to Section 5.1.1 for a description of this technology
Diesel Particulate Filter (DPF)	Refer to Section 5.1.1 for a description of this technology
Oxidation Catalyst	Refer to Section 5.1.1 for a description of this technology

6.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the potential control technologies is summarized in Table I.6-2.

Table I.6-2 Technical Feasibility of PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Emergency Diesel Engine Generators

Technology	Technically Feasible?
Use of ULSD	Yes
Emergency Use Classification	Yes
Compliance with NSPS IIII	Yes
Good Combustion Practices	Yes
Diesel Particulate Filter (DPF)	No
Oxidation Catalyst	No

DPFs and oxidation catalysts are technically feasible for diesel engines that operate at steady-state for extended periods of time. Given the intermittent operation of the proposed engines, particulates collected on the filter or oxidation catalyst may not reach high enough temperatures to oxidize, even in the presence of a catalyst. This may lead to plugging and thus DPFs and oxidation catalysts are not considered to be technically feasible for this application. The engine will only operate a few hours each month for readiness testing and maintenance checks and will be permitted to operate for no more than 500 hours/12-month rolling period. Therefore, this control technology is not considered further in this analysis.

6.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.6-3 according to their control effectiveness.

Table I.6-3 Ranking of Remaining PM, PM_{10}, $PM_{2.5}$ Emission Control Technologies for the Emergency Diesel Engine Generators

Rank	Technology	Estimated Control Efficiency
1	Emergency Use Classification	94%
N/A	Use of ULSD	Inherently lower emissions
N/A	Certified Engine per NSPS IIII	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

6.1.4 Step 4 – Evaluation of Feasible Control Technologies

Xcel has selected the top performing technically feasible control technologies so no economic, energy, or environmental impacts analysis is needed.

6.1.5 Step 5 – BACT Selection

Xcel selects emergency use-classification, use of only ULSD fuel, purchase of a certified Tier 2 engine in accordance with NSPS IIII requirements, and good combustion practices as BACT for the emergency diesel

engine generators. This is consistent with many determinations in the RBLC. Refer to Attachment I.2-3 for more detail. BACT limits are summarized in Table I.6-4.

Table I.6-4 Proposed PM, PM_{10}, $PM_{2.5}$ BACT Limits for the Emergency Diesel Engine Generators

Parameter	Limit		
Performance Limitation	PM g/kW-hr	PM10 g/kW-hr	PM2.5 g/kW-hr
	0.20	0.22	0.22
Mass Emission Limitation	PM lb/hr	PM_{10} lb/hr	$PM_{2.5}$ lb/hr
Each 750 kW Emergency Generator	0.34	0.39	0.39
Each 550 kW Emergency Generator	0.25	0..29	0.29
Opacity Limits for Each Engine	20% during acceleration mode, 15% during the lugging mode, and 50% during peaks in acceleration and lugging modes.		
Operating Limits for Each Engine	Each engine may only operate 500 hours/year		
Compliance Demonstration	Purchase a certified Tier 2 engine and comply with applicable NSPS IIII requirements, burn only ULSD, and operate engine in accordance with manufacturer specifications during normal operation and start-up/shutdown conditions.		

6.2 Emergency Diesel Engine Generators NO_X Emissions

NO_X emissions are formed during combustion of the diesel fuel in the emergency engines. The NO_X is formed from oxidation of nitrogen in the combustion air and oxidation of fuel bound nitrogen.

6.2.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling NO_X emissions are summarized in Table I.6-5.

Table I.6-5 Available NO_X Emission Control Technologies for the Emergency Diesel Engine Generators

Technology	Description
Use of Ultra-low Sulfur Diesel (ULSD)	Use of ULSD fuel will limit the formation of fuel bound NO_X emissions. Much of the fuel bound nitrogen is removed during the desulfurization process.
Emergency Use Classification	Refer to Section 6.1.1 for a description
Compliance with NSPS IIII	Refer to Section 6.1.1 for a description
Good Combustion Practices	Refer to Section 6.1.1 for a description
Selective Non-Catalytic Reduction (SNCR)	Refer to Section 4.2.1 for a description
Selective Catalytic Reduction (SCR)	See Section 4.2.1 for a description
Non-Selective Catalytic Reduction (NSCR)	See Section 4.2.1 for a description

6.2.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the potential control technologies is summarized in Table I.6-6.

Table I.6-6 Technical Feasibility of NO_X Emission Control Technologies for the Emergency Diesel Engine Generators

Technology	Technically Feasible?
Use of Ultra-low Sulfur Diesel (ULSD)	Yes
Emergency Use Classification	Yes
Compliance with NSPS IIII	Yes
Good Combustion Practices	Yes
Selective Non-Catalytic Reduction (SNCR)	No
Selective Catalytic Reduction (SCR)	No
Non-Selective Catalytic Reduction (NSCR)	No

6.2.2.1 SNCR

SNCR is not feasible because engine temperatures do not meet the SNCR reaction temperature range of 1,600° F to 2,000° F. Engine exhaust temperatures are below 1,000° F.

6.2.2.2 SCR

SCR needs steady state operating conditions with consistent exhaust gas compositions and operating temperatures for it to function effectively. If not, operating temperatures will vary outside of the SCR catalyst operating temperature window and it will be difficult to control reagent addition rates. The diesel emergency CI engines will operate infrequently and under either emergency conditions or for short periods during periodic testing. Neither of these conditions are conducive to maintaining the steady state operating conditions needed for SCR. Therefore, SCR is not feasible for this application.

6.2.2.3 NSCR

NSCR is not feasible in the in the emergency diesel engine generators because diesel engines operate with lean-burn air to fuel ratios. NSCR requires rich air to fuel combustion ratios to generate CO concentrations needed for the NSCR catalyst to function. Rich burn engines operate with O_2 levels at 1% or less. Diesel CI engines operate at O_2 levels higher than 1% (reference (8)).

6.2.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.6-7 according to their control effectiveness.

Table I.6-7 Ranking of Remaining NO_X Emission Control Technologies for the Emergency Diesel Engine Generators

Rank	Technology	Estimated Control Efficiency
1	Emergency Use Classification	94%
N/A	Use of ULSD	Inherently lower emissions
N/A	Certified Engine per NSPS IIII	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

6.2.4 Step 4 – Evaluation of Feasible Control Technologies

Xcel has selected the top performing technically feasible control technologies so no economic, energy, or environmental impacts analysis is needed.

6.2.5 Step 5 – BACT Selection

Xcel selects emergency use-classification, purchase of a certified Tier 2 engine in accordance with NSPS IIII requirements, and good combustion practices as BACT for the emergency diesel engine generators. This is consistent with many determinations in the RBLC. Refer to Attachment I.2-3 for more detail. BACT limits are summarized in Table I.6-8.

Table I.6-8 Proposed BACT NO_X Limitations for the Emergency Generators

Category	Demonstration
Limitations	NSPS IIII limits for NO_X and non-methane hydrocarbons (NMHC, surrogate for VOC) are combined for emergency engines. Therefore, the sum of NMHC (surrogate for VOC) and NO_X are limited to 6.4 g/kW-hr, 11.03 lb/hr for the 750 kW generators, and 8.12 lb/hr for the 550 kW generators.
	Each engine may only operate 500 hours/year
Compliance Demonstration	Purchase a certified Tier 2 engine and comply with applicable NSPS IIII requirements, burn only ULSD, and operate engine in accordance with manufacturer specifications during normal operation and start-up/shutdown conditions

6.3 Emergency Diesel Engine Generators CO/VOC Emissions

CO and VOC emissions are formed as a result of incomplete combustion in diesel engines. Controlling CO and VOC emissions will also limit emissions of organic HAPs.

6.3.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling CO/VOC emissions are summarized in Table I.6-9.

Table I.6-9 Available CO/VOC Emission Control Technologies for the Emergency Diesel Engine Generators

Technology	Description
Emergency Use Classification	Refer to Section 6.1.1 for a description
Compliance with NSPS IIII	Refer to Section 6.1.1 for a description
Good Combustion Practices	Refer to Section 6.1.1 for a description
Oxidation Catalyst	Refer to Section 5.1.1 for a description
Non-Selective Catalytic Reduction (NSCR)	See Section 4.2.1 for a description

6.3.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the potential control technologies is summarized in Table I.6-10.

Table I.6-10 Technical Feasibility of CO/VOC Emission Control Technologies for the Emergency Diesel Engine Generators

Technology	Technically Feasible?
Emergency Use Classification	Yes
Compliance with NSPS IIII	Yes
Good Combustion Practices	Yes
Oxidation Catalyst	No
Non-Selective Catalytic Reduction (NSCR)	No

6.3.2.1 Oxidation Catalyst

As discussed in Section 6.1.2, oxidation catalysts are not feasible for the proposed emergency engines.

6.3.2.2 NSCR

As discussed in Section 6.1.2, NSCR is not feasible for the proposed emergency engines.

6.3.3 Step 3 – Effectiveness of Feasible Control Technologies

The technically feasible control options are ranked in Table I.6-11 according to their control effectiveness.

Table I.6-11 Ranking of Remaining CO/VOC Emission Control Technologies for the Emergency Diesel Engine Generators

Rank	Technology	Estimated Control Efficiency
1	Emergency Use Classification	94%
N/A	Certified Engine per NSPS IIII	Inherently lower emissions
N/A	Good Combustion Practices	Inherently lower emissions

6.3.4 Step 4 – Evaluation of Feasible Control Technologies

Xcel has selected the top performing technically feasible control technologies so no economic, energy, or environmental impacts analysis is needed.

6.3.5 Step 5 – BACT Selection

Xcel selects emergency use-classification, purchase of a certified Tier 2 engine in accordance with NSPS IIII requirements, and good combustion practices as BACT for the emergency diesel engine generators. This is consistent with many determinations in the RBLC. Refer to Attachment I.2-3 for more detail. BACT limits are summarized in Table I.6-12.

Table I.6-12 Proposed BACT CO/VOC Limitations for the Emergency Generators

Category	Demonstration
Limitations	CO is limited to 3.5 g/kW-hr, 6.03 lb/hr for the 750 kW generators, and 4.44 lb/hr for the 550 kW generators. Tier 2 for NO_X and NMHC (surrogate for VOC) are combined for emergency engines. Therefore, the sum of NMHC (surrogate for VOC) and NO_X are limited to 6.4 g/kW-hr, 11.03 lb/hr for the 750 kW generators, and 8.12 lb/hr for the 550 kW generators.
	Each engine may only operate 500 hours/year
Compliance Demonstration	Purchase a certified Tier 2 engine and comply with applicable NSPS IIII requirements, burn only ULSD, and operate engine in accordance with manufacturer specifications during normal operation and start-up/shutdown conditions

6.4 Emergency Generators GHG Emissions

The GHG BACT analysis for the Emergency Generators is included in Section 7.

7 Facility-wide Combustion Sources GHG BACT

The GHG BACT for the combustion turbines, engine generators, and emergency engines is included below.

7.1 Combustion Turbines, Engine Generators, and Emergency Engines GHG Emissions

CO_2 emissions occur from the combustion turbines, engine generators, and emergency engines. CH_4 and N_2O will also be emitted as a byproduct of combustion. The control technology options discussed below focus on CO_2 emissions, but most BACT limits will be in the form of CO_2 equivalents (CO_2e) to account for the low levels of other GHG combustion byproducts (i.e. CH_4 and N_2O). The GHG control technologies will be evaluated for the project GHG emitting units both individually for technologies that lower the amount of emissions from each unit as well as to a combined control device for any add-on controls that will be applied to all GHG emitting units that are a part of this project.

7.1.1 Step 1 – Identify All Available Control Technologies

Table I.7-1, contains a summary of the available GHG emissions control technologies for the project and additional detail is in Sections 7.1.2.1 and 7.1.2.3 for each technology.

Table I.7-1 Available GHG Emission Control Technologies

Technology		Description
Carbon Capture, Utilization and Sequestration or Storage	Carbon Capture	Carbon capture systems produce a concentrated and pressurized stream of CO_2, which is then compressed for transport and/or storage.
	Carbon Transport and Storage	Carbon transport and storage involves compressing and transporting captured CO_2 to a suitable disposal site for deep underground storage in geological formations.
	Carbon Utilization	Carbon utilization involves the use or transformation of CO_2 and other carbon byproducts and wastes into valuable products in an efficient, economical, and environmentally friendly manner.
Clean Fuels		Combustion of a low carbon fuel, resulting in lower CO_2 emissions per unit of fuel combusted.
Good Combustion Practices and Energy Efficiency Measures		Minimizing GHG emissions by reducing the amount of fuel burned through energy efficiency measures. Energy efficiency measures may include energy efficient equipment design, minimizing heat loss, waste heat recovery and good operating and maintenance practices.

7.1.1.1 Carbon Capture, Utilization, and Sequestration or Storage (CCUS)

CCUS is an emerging technology involving capture and either utilization or storage of CO_2 emissions to prevent their release to the atmosphere. For the project emission units, this includes removal of CO_2 emissions from the exhaust stream, transportation of the CO_2 to an injection site or utilization facility, and

injection of the CO_2 into available sequestration sites or transformation into other products. Potential CO_2 sequestration sites are geological formations (including oil and gas fields). CO_2 utilization is an emerging field which encompasses primarily fuels, organic and inorganic chemicals, food and feeds, construction materials, enhanced resource recovery (e.g., oil, gas, water, and geothermal energy), energy storage, and wastewater treatment (reference (9)).

The fundamental physical processes and engineering aspects of CCUS are well understood, and portions of a CCUS system are technically mature. However, CCUS is a developing technology that is not yet fully commercially available in the application of post-combustion capture, nor widely applied, especially for natural gas combustion sources. Nevertheless, in the March 2011 Guidance reference (10)), the EPA classified CCUS as an add-on control technology that is "available" for purposes of the Step 1 listing in GHG BACT analyses for facilities emitting CO_2 in large amounts, such as fossil fuel-fired power plants, and for certain industrial facilities with high-purity CO_2 streams.

The Project's combustion emission units do not meet the criteria for the types of sources at which CCUS should be considered presumptively available. Relatively low CO_2 stack concentrations complicates the absorption and desorption of the CO_2 making capture of CO_2 significantly more difficult than from a highly concentrated stream.

Low concentration low pressure streams, such as those that will be generated at this facility, increase the energy requirements of the system. In fact, the EPA's NSPS for GHGs from electric generating units[7] highlights the importance of these distinctions. Speaking to the exhaust stream from natural gas-fired combustion turbines, EPA noted that the agency did not know of any demonstrations of natural gas turbines implementing CCUS that would justify setting a national standard. Because Xcel is unaware of any carbon capture systems that have been demonstrated on a diluted CO_2 stream, carbon capture, and by extension, CCUS, is not available for implementation on the combustion turbines, engine generators, or the emergency engines. Xcel will nonetheless evaluate CCUS in Steps 2 and 4 (Sections 7.1.2 and 7.1.4) of this top-down analysis.

7.1.1.2 Clean Fuels

Consistent with the EPA's permitting guidance, clean fuels that result in lower GHG emissions than other fuels should be considered as a control technology, understanding that the BACT analysis does not need to include a clean-fuel option that would fundamentally redefine the source (reference (10)). Natural gas consists primarily of methane (CH_4), which has relatively low carbon content and therefore produces lower emissions of CO_2 when combusted compared to other hydrocarbons. Of the 60 fuel types listed in Table C-1 of 40 CFR 98, natural gas has a lower CO_2 emission rate than all but two—coke-oven gas and biogas, neither of which is an available fuel because there are no coke ovens or large sources of biogas in the vicinity of the Project. The use of these fuels would also fundamentally redefine the emission sources in which natural gas is used, the combustion turbines and DF mode for the engine generators. The engine

[7] *See* 80 Fed. Reg. 64,510-64,614 (Oct. 23, 2015).

generators can also combust 100% diesel. The engine generators will occasionally be operated on only diesel, but only for maintenance, testing and during emergency situations.

7.1.1.3 Good Combustion Practices and Energy Efficiency Measures

Efficient design and good combustion practices are paramount in minimizing CO_2 emissions for combustion sources. By designing and operating combustion sources with a higher efficiency, less fuel is burned, reducing the amount of each CO_2 produced as a product or byproduct of combustion. The EPA emission factors for CO_2 from combustion sources are established on the basis of fuel consumption measured in MMBtu of fuel as fired. Improvements in overall combustion unit efficiency ensure that more of the energy (in terms of MMBtu fired) is recovered as useful output in the process instead of being lost as unutilized heat that is discharged as high temperature exhaust gases. This reduces total fuel consumption and limits GHG emissions.

Energy-efficient design and operation measures that are available for minimizing CO_2 emissions include energy-efficient equipment design, heat-loss minimization, waste-heat recovery, and good operating and maintenance practices. The feasibility of these available energy efficiency measures are reviewed and summarized in Section 7.1.2 below.

7.1.2 Step 2 – Technical Feasibility of Control Technologies

The technical feasibility of the control options for CO_2 emissions from the combustion turbines, engine generators, and emergency generators are carried forward from Step 1 and summarized in Table I.7-2, Table I.7-3, and Table I.7-4. Additional discussion for each emission units is discussed further in the following sub sections.

Table I.7-2 Technical Feasibility of CO_2 Control Technologies for the Combustion Turbines

Technology	Demonstrated in Practice?	Technically Feasible?
CCUS	Yes	No
Clean Fuels	Yes	Yes
Good Combustion Practices and Energy Efficiency Measures	Yes	Yes

Table I.7-3 Technical Feasibility of CO_2 Control Technologies for the Engine Generators

Technology	Demonstrated in Practice?	Technically Feasible?
CCUS	Yes	No
Clean Fuels (Natural Gas in DF mode)	Yes	Yes
Good Combustion Practices	Yes	Yes

Table I.7-4 Technical Feasibility of CO_2 Control Technologies for the Emergency Generators

Technology	Demonstrated in Practice?	Technically Feasible?
CCUS	No - rare and intermittent operation	No - rare and intermittent operation
Clean Fuels (Natural Gas)	N/A	No – redefines source
Good Combustion Practices	Yes	Yes

7.1.2.1 CCUS

In addition to the availability concerns noted in Section 7.1.1, a carbon capture technology that removes CO_2 in gaseous form but does not provide viable long-term storage/utilization method or a transportation system, will not accomplish the goal of removing CO_2 from the atmosphere. Therefore, in order for carbon capture technology to be considered a technically feasible control option for consideration as BACT, carbon capture with an option for transport or storage must be examined and deemed available and technically feasible for the proposed project.

Methods for post-combustion capture of the CO_2 include the following methods (reference (11)):

- Absorption - Solvents
- Adsorption - Sorbents
- Membranes

Absorption utilizes a liquid solvent (carrier) to physically absorb the CO_2 from the flue gas. The solvent is then regenerated by either high-temperatures or low-pressures to release the CO_2 bonds. The most common example of this capture method is an aqueous amine solution. Though low-cost and high-capacity, amine solutions require regeneration, which is a high energy and, therefore, expensive process. During regeneration, the aqueous amine solution that reacts with CO_2 to form carbamates which possesses drawbacks, such as being highly corrosive, yields toxic degradation products, and requiring significant energy to remove CO_2. This process is also sensitive to flue gas impurities which reduce the amount of CO_2 that can be absorbed.

Alternatively, solid sorbents can adsorb CO_2. The regeneration process for solid sorbents is similar to the process for solvents. High temperatures or low pressures facilitate the release of captured CO_2. While solid sorbents have been introduced, they suffer from low CO_2 capacity in the presence of water, poor stability over multiple absorption-desorption cycles, and a high production cost (reference (12)). These solid sorbents are also higher in cost than the traditional aqueous amine solution systems.

A relatively new method for CO_2 capture uses permeable or semi-permeable membranes to selectively separate and transport the CO_2 from the flue gas. Membranes for CO_2 capture do not suffer from the some of the potential drawbacks of the other systems discussed above including hazardous chemical

issues, intolerance of flue gas impurities, and process intensive operation. However, the relatively low partial pressure of CO_2 in combustion flue gases and the high cost makes this technology less feasible.

CO_2 concentrations from natural gas combustion are relatively low in comparison to the combustion of coal. A prominent post-combustion CCS facility that operated in the United States is the Petra Nova electrical generation facility near Houston, Texas. The Petra Nova facility used coal as its combustion source and is also a commercial electrical generation facility. The carbon capture technology costs at the facility were reported to be approximately $1 billion ($4,200/kW) (reference (13)); however, the costs were also offset by a $190 million U.S. Department of Energy grant (reference (14)). Further, this facility has been shut down as of May 2020. For the reasons discussed here and in Step 1 above, Xcel does not consider post-combustion capture to be either an available or practically feasible control technology for the proposed project.

Any method of capture will also require the conversion of the CO_2 gas to a liquid, typically through compression, for storage or transport. Such equipment is expensive and requires a means to transport the compressed CO_2. While it may be possible to construct a pipeline to transport captured CO_2 to a sequestration site, there are many challenges involved with pipeline construction and permitting, and approval with applicable authorities. Therefore, CO_2 transport from the facility is not considered to be technically feasible.

Further, a suitable injection location is required in order to store captured CO_2. According to the National Energy Technology Laboratory (NETL) carbon storage tool (reference (15)), there are no viable carbon storage locations anywhere near Minnesota, making carbon storage technically infeasible. However, known uses of captured CO_2 are for enhanced resource recovery (e.g., oil). The closest industrial user or location with any kind of CO_2 pipeline infrastructure is Dakota Gasification Company in North Dakota (reference (16)). It is assumed for this analysis that the captured CO_2 could theoretically be piped to Dakota Gasification Company and distributed out to other locations for long-term storage. While this scenario is entirely theoretical, Xcel estimated the costs to construct a pipeline to the Dakota Gasification Company as a part of Step 4's cost evaluation. However, it is unknown if this facility would be able to accommodate captured CO_2 from Xcel and no commercial contract is place for CO_2 deposition for the life of the facility, so this is not considered to be technically feasible.

Finally, CCUS is not considered to be technically feasible due to the short and long-term uncertainty and risks surrounding the design, installation, and operation of a CCUS project. These risks include:

- The existence of market failures, particularly the lack of a cohesive climate policy setting a price on carbon and encouraging emission reductions;
- The need for a legal and regulatory framework for CCS projects that facilitates project development, protects human health and the environment, and addresses public concerns whether CO_2 can be stored safely and securely;

- Improved industry confidence regarding the long-term liability for CO_2 storage, particularly regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages; and
- Integration of public information, education, and outreach throughout the CCS project lifecycle in order to foster public understanding and to build trust between communities and project developers.

7.1.2.2 Clean Fuels

Consistent with the EPA's permitting guidance, clean fuels result in lower GHG emissions than other fuels and should be considered as a control technology, with the understanding that the BACT analysis cannot include a clean fuel option that would fundamentally redefine the source (reference (10)). For purposes of these projects, reduction of GHG emissions through use of clean fuels, as defined above in Section 7.1.1, is technically feasible for the combustion turbines and engine generators (only when operating in DF mode), with the exception of the emergency generators because it would fundamentally redefine the source.

7.1.2.3 Good Combustion Practices and Energy Efficiency Measures

The feasibility and implementation of each applicable energy efficiency measures is summarized in Table I.7-5 for the combustion turbines.

Table I.7-5 Technical Feasibility of Energy Efficiency Measures for Reducing GHG Emissions from the Combustion Turbines

Energy Efficiency Measure Description	Feasible? Yes or No	Proposed Implementation
Evaporative (Wet) Cooling	Yes	Both combustion turbines at the Blue Lake facility have evaporative wet cooling on the air intake to condition the inlet air.
Combustion Tuning & Optimization	Yes	Xcel already conducts tuning as required. Addition of CEMS will support combustion tuning after completion of the project.
Instrumentation and Controls	Yes	
Reduce Air Leakage	Yes	Air leakage monitoring is already an essential part of Xcel's monitoring practices

The energy efficiency measures for the combustion turbines do not apply to the engine generators and emergency engines. RICE efficiency will be maintained by operating the engines in accordance with manufacturer specifications and conducting required maintenance. Further, the both the generators and emergency engines are new and will be inherently efficient.

7.1.3 Step 3 - Effectiveness of Feasible Control Technologies

The use of natural gas as a primary fuel source along with good combustion practices and the implementation of the technically feasible operational energy-efficiency measures are the only technically

feasible control options for minimizing GHG emissions from the project. The energy-efficiency measures which will be implemented as a part of the project are included in

Table I.7-5. The combination of these measures is therefore the top-ranked control technology. Implementing energy-efficiency operational measures results in less fuel firing and lower GHG emissions, and is consistent with a survey of recent GHG BACT limitations listed in the RBLC database. Refer to Attachment I.2 for more detail.

Xcel believes that CCUS is not an available or technically feasible GHG control option at this time; however, it has been carried through the rest of the five-step process.

7.1.4 Step 4 - Evaluation of Feasible Control Technologies

The use of natural gas (where applicable) as the fuel source and good combustion practices as the GHG emissions control technologies have no appreciable adverse energy, environmental, or economic impacts and therefore are consistent with BACT.

While there are numerous technical challenges associated with CCUS, Xcel has provided a cost evaluation to support that CCUS is not economically feasible. CCUS capital costs were estimated by scaling an estimate from a 2015 NETL study (reference (17)) . The pipeline capital cost was estimated using the 2018 National Energy Technology Laboratory (NETL) spreadsheet (reference (18)). The FE/NETL transportation cost calculation spreadsheet includes estimated revenues as part of the calculation, however, these revenues are not guaranteed as part of the project and no contracts are in place with industrial users for the purchase of any CO_2 captured as a part of the project. Therefore, the revenues included in the cost calculation spreadsheet are not included for this analysis. The closest industrial user or location with any kind of CO_2 capture infrastructure is the Dakota Gasification Company. It is assumed for this analysis that the captured CO_2 could theoretically be piped to the Dakota Gasification Company Plant and distributed to other locations for long-term storage. A minimum pipeline length of 430 miles is conservatively estimated. The additional costs of site-specific issues were not included in this evaluation. Control costs are summarized in Table I.7-6 and the details are included in Attachment I.1-3.

Table I.7-6 Economic Feasibility of CCUS for CO_2 Emissions at the Facility

Control Technology	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Pollution Control Cost ($/ton CO_2)
Carbon Capture and Sequestration (CCUS)	$1,498 Million	$148 Million	$83

The estimated CCUS costs are extreme and unacceptable to Xcel. The costs of CCUS greatly exceeds the cost of the project is not considered economically feasible.

Based on a study published by the Massachusetts Institute of Technology (reference (19)) , the estimated incremental energy requirement to operate CCUS could be 67 MW, which is not included in the operating costs above. This would require several additional generators or purchased power from the grid.

Therefore, the energy requirements for CCUS are unacceptable. Further, the additional electric generation would produce collateral emissions.

7.1.5 Step 5 – BACT Selection

Use of natural gas fuel for the combustion turbines and engine generators (when operating in DF mode), implementation of good combustion practices, and operational energy-efficiency measures for the combustion turbines are proposed as BACT. The rationale for this selection is as follows:

- Energy conservation is a work practice, which minimizes GHG emissions and is consistent with previous BACT determinations for GHG Emissions.
- CCUS is not technically or economically feasible. Further, CCUS has significant incremental energy requirements with associated collateral combustion emissions to generate the required electricity.

Proposed BACT Emission Limits for combustion sources subject to GHG BACT are summarized in Table I.7-7 through Table I.7-9.

Table I.7-7 Proposed GHG BACT Limits for the Combustion Turbines

Category	Demonstration
Performance Limitation	120 lb CO_2/MMBtu
Mass Emission Limitation	986,539 tons CO_2e/yr 12-month rolling sum
Compliance Demonstration	Combust only natural gas fuel, good combustion practices, and energy efficiency measures.

Table I.7-8 Proposed GHG BACT Limits for Engine Generators

Category	Demonstration
Performance Limitation	DF mode – 512 g CO_2/kWhe Diesel mode – 672 g CO_2/kWhe
Mass Emission Limitation	72,583 tons CO_2e per 12-month rolling sum.
Compliance Demonstration	Good combustion practices, fuel use tracking, and recordkeeping.

Table I.7-9 Proposed GHG BACT Limits for Emergency Engines

Category	Demonstration
Mass Emission Limitation	Each 750 kW generator – 314 tons CO_2e/yr 12-month rolling sum Each 550 kW generator – 231 tons CO_2e/yr 12-month rolling sum
Work Practice	Good combustion practices
Compliance Demonstration	Operate and maintain engines in accordance with manufacturer specifications and purchase certified engines.

In order to monitor compliance with the proposed GHG BACT limits, the permittee shall maintain compliance with applicable subparts of 40 CFR Part 98 (Mandatory Greenhouse Gas Reporting Rule) including flow monitoring of fuel usage. The facility will also track the number of hours of operation. Xcel's monitoring of the units includes continuous fuel flow monitoring while the unit is in operation. Flow data multiplied by the emission factors (EF) referenced in the project emission inventory results in a more accurate quantification of GHG emissions than a stack Continuous Emissions Monitoring System (CEMS) requirement to meet a 20 percent relative-accuracy standard per Performance Specification 6 in Appendix B of 40 CFR 60. Xcel will calculate CO_2e emissions (including CO_2, CH_4, and N_2O), on a 12-month rolling-sum basis. The global warming potentials (GWPs) used to calculate total CO_2e pounds are shown in Table I.7-10.

Table I.7-10 Global Warming Potentials used for Compliance Monitoring

Greenhouse Gas	Global Warming Potentials
CO_2	1
CH_4	25
N_2O	298

From 40 CFR 98 Subpart A

8 References

1. **U.S. Environmental Protection Agency.** New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting-Draft. October 1990.

2. **Alaska LNG.** Liquefaction Plant Best Available Control Technology (BACT) Analysis. April 13, 2022.

3. **Minndsota Pollution Control Agency.** Northern States Power Company d/b/a Xcel Energy Air Emission Permit No. 12300012-004. August 12, 2005. Xcel Energy - High Bridge Generating Plant.

4. *Evaluation of the Performance of EPA Methods 201A and 202 on a Natural Gas-Fired Boiler.* **Jain, Ashok and Carlson, Lee (NCASI).** Minneapolis, MN : s.n., 2013. Conference on the Environment.

5. **U.S. Environmental Protection Agency.** Air Pollution Control Technology Fact Sheet Selective Non-Catalytic Reduction (SNCR). 2003.

6. **Sorrels, John L. and Walton, Thomas G.** Chapter 2 Cost Estimation: Concepts and Methodology. [Online] 2018. https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

7. **ONSITE SYCOM Energy Corporation.** Cost Analysis of NOX Control Alternatives for Stationary Gas Turbines. November 5, 1999. Prepared for U.S. Department of Energy.

8. **Jääskeläinen, Hannu and Khair, Magdi K.** Combustion in Diesel Engines. *DieselNet Technology Guide.* [Online] May 2020.

9. **National Energy Technology Laboratory.** Carbon Conversion Program. [Online] https://netl.doe.gov/carbon-management/carbon-conversion.

10. **U.S. Environmental Protection Agency.** PSD and Title V Permitting Guidance for Greenhouse Gases (EPA-457/B-11-001). March 2011.

11. **National Energy Technology Laboratory.** Point Source Carbon Capture Program. [Online] https://netl.doe.gov/carbon-management/carbon-capture.

12. **Vericella, John J., et al.** Encapsulated Liquid Sorbents for Carbon Dioxide Capture. *Nature Communications.* 2015, Vol. 6. Article number: 6124.

13. **U.S. Energy Information Administration.** Petra Nova is one of two carbon capture and sequestration powerplants in the world. [Online] October 31, 2017. https://www.eia.gov/todayinenergy/detail.php?id=33552.

14. **NRG Energy, Inc.** Carbon capture and the future of coal power. [Online]

15. **National Energy Technology Laboratory.** Technology Area Interactive Project Map. [Online]

16. —. A Review of the CO2 Pipeline Infrastructure in the U.S. April 21, 2015. DOE/NETL2014/1681.

17. **National Energy Technology Lab.** Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3. July 6, 2015. DOE/NETL-2015/1723.

18. **National Energy Technology Laboratory.** FE/NETL CO2 Transport Cost Modell: Description and User's Manual. Pittsburgh, Pennsylvania : U.S. Department of Energy, May 2018. Version 2b.

19. **David, Jeremy and Herzog, Howard.** The Cost of Carbon Capture. n.d.

20. **Pleasant Ridge, LLC.** Pleasants Energy Uprate Project PSD Application (WV Primary ID# 073-00022). https://documents.dep.wv.gov/AppXtender/datasources/DEPAX16/applications/40/document/23382?lqid=-1&lqrid=%7B1c7bdd45-b213-49e9-a43d-a2e0601bbb73%7D&lqaid=40&qrid=%7B1c7bdd45-b213-49e9-a43d-a2e0601bbb73%7D&qridx=8.

21. **U.S. Environmental Protection Agency.** Verified Technologies List for Clean Diesel. https://www.epa.gov/verified-diesel-tech/verified-technologies-list-clean-diesel

22. **California Air Resource Board.** Verified Technologies List for Level 3 - 85 Percent or Greater Reduction in Particulate Matter. https://ww2.arb.ca.gov/diesel/verdev/vt/stationary.htm

Attachments

Attachment I.1

Attachment I.1-1 Combustion Turbines NOX Control Costs
Attachment I.1-2 Combustion Turbines CO/VOC Control Costs
Attachment I.1-3 GHG Control Costs

Attachment I.1 Control Cost Worksheets

Attachment I.1-1

Combustion Turbines NO_X Control Costs

Attachment I.1-1 Combustion Turbines NO_X Control Costs

Data Inputs

Vendor estimate for purchased equipment cost with an engineering estimate for installation costs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 174 MW

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 1,524,240 MWhs

1615 MMBtu/hr

Enter the net plant heat input rate (NPHR) 9.28 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Shakopee, MN

Plant Elevation 768 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.036	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.007	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	2	
Number of empty catalyst layers (R_{empty})	0	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	2,558,256	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	40,000	hours
Estimated SCR equipment life	20	Years*

Gas temperature at the SCR inlet (T)	925	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2022				
CEPCI for 2022	816.3	Enter the CEPCI value for 2022	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent			
Reagent ($Cost_{reag}$)	0.605	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.0921	$/kWh			
Catalyst cost ($CC_{replace}$)	265.59	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	70.20	$/hour (including benefits)			
Operator Hours/Day	4.00	hours/day*			

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Scaled up ammonia costs to 2021 dollars using the most recent U.S. Geological Survey, Minerals Commodity Summaries for fixed nitrogen.
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	Used May 2022 Minnesota electrical industrial price from https://www.eia.gov/electricity/data/browser/#/topic/7?agg=1,0&geo=g00004&endsec=2&freq=M&start=200101&end=202205&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Scaled to present day using the Minneapolis Federal Reserve Bank Inflation Calculator here: https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Scaled to present day using the Minneapolis Federal Reserve Bank Inflation Calculator here: https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator
Interest Rate (Percent)	7	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,615	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,524,240	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		1,524,240	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.93		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	81.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	47.57	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	208.35	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.02		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,558,256	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	229.60	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6] $^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1), where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1739	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	11,142.05	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,665	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,065	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	55.4	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	29	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	64	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,900	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ =	141.55	kW
	where A = Bmw for utility boilers		

Use 15% of EPA correlation for combustion turbine to account for reagent vaporization and injection system operation. Per Table 2.8 in SCR cost manual, 80% to 90% of power consumption is associated with induced draft fan operation. No fan required for combustion turbine exhaust besides the tempering air fan, which is calculated separately.

Cost Estimate

Total Capital Investment (TCI)

Vendor estimate for purchased equipment cost with an engineering estimate for installation costs

Total Capital Investment (TCI) =	**$61,106,208**	in 2022 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,378,813	in 2022 dollars
Indirect Annual Costs (IDAC) =	$5,775,167	in 2022 dollars
Total annual costs (TAC) = DAC + IDAC	$7,153,980	in 2022 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$305,531	in 2022 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$45,130	in 2022 dollars
Annual ***SCR*** Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$114,201	in 2022 dollars
Annual ***Tempering Air Fan*** Electricity Cost =		$121,967	in 2022 dollars
Lost Electrical Production Due to SCR =		$534,680	in 2022 dollars
Annual Catalyst Replacement Cost =		$257,304	in 2022 dollars
Direct Annual Cost =		$1,378,813	in 2022 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$6,741	in 2022 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$5,768,426	in 2022 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$5,775,167	in 2022 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$7,153,980	per year in 2022 dollars
NOx Removed =	208	tons/year
Cost Effectiveness =	$34,336	per ton of NOx removed in 2022 dollars

Xcel Energy - Blue Lake
Simple Cycle Hot SCR Installation Costs

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment			
Purchased Equipment Costs (A) from Vendor			30,000,000
Sales Taxes	6.9%	of purchased equipment costs	2,063,000
Freight	0%	Included below	0
Purchased Equipment Total (B)	7%		**32,063,000**
Installation			
Foundations/Supports	8%	of purchased equipment costs	2,565,000
Handling and Erection	14%	of purchased equipment costs	4,489,000
Electrical	4%	of purchased equipment costs	1,283,000
Piping	2%	of purchased equipment costs	641,000
Insulation	1%	of purchased equipment costs	321,000
Painting	1%	of purchased equipment costs	321,000
Installation Total			**9,620,000**
Total Direct Capital Cost, DC			**41,683,000**
Indirect Capital Costs			
Construction and Field Expenses	10%	of purchased equipment total	3,206,000
Contractor Fees	5%	of purchased equipment total	1,603,000
Start-up	10%	of purchased equipment total	3,206,000
Performance test	2%	of purchased equipment total	641,000
Model Studies	1%	of purchased equipment total	321,000
Contingencies	3%	of purchased equipment total	962,000
Total Indirect Capital Costs, IC			**9,939,000**
Total Capital Investment (TCI) = DC + IC			**51,622,000**
Vendor Logistics and Delivery		Vendor estimate	9,000,000
Total Site Specific Costs			**9,000,000**
Adjusted TCI for Replacement Parts (Catalyst, Filter Bags, etc) for Capital Recovery Cost			**60,622,000**
Total Capital Investment (TCI) with Retrofit Factor	0%		**60,622,000**

Data Inputs

SCR Engineering Installed Capital Cost Estimate Basis

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 174 MW

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 1,524,240 MWhs

1615 MMBtu/hr

Enter the net plant heat input rate (NPHR) 9.28 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Shakopee, MN

Plant Elevation 768 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ◉ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.036	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.007	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.050	

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	2	
Number of empty catalyst layers (R_{empty})	0	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	2,558,256	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	40,000	hours
Estimated SCR equipment life	20	Years*

Gas temperature at the SCR inlet (T)	925	°F
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484	ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	29	percent*
Density of reagent as stored (ρ_{stored})	56	lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14	days

*The reagent concentration of 29% and density of 56 lbs/cft are default values for ammonia reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2022				
CEPCI for 2022	816.3	Enter the CEPCI value for 2022	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7	Percent			
Reagent ($Cost_{reag}$)	0.605	$/gallon for 29% ammonia			
Electricity ($Cost_{elect}$)	0.0921	$/kWh			
Catalyst cost ($CC_{replace}$)	265.59	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			
Operator Labor Rate	70.20	$/hour (including benefits)			
Operator Hours/Day	4.00	hours/day*			

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Scaled up ammonia costs to 2021 dollars using the most recent U.S. Geological Survey, Minerals Commodity Summaries for fixed nitrogen.
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	Used May 2022 Minnesota electrical industrial price from https://www.eia.gov/electricity/data/browser/#/topic/7?agg=1,0&geo=g00004&endsec=2&freq=M&start=200101&end=202205&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Scaled to present day using the Minneapolis Federal Reserve Bank Inflation Calculator here: https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Scaled to present day using the Minneapolis Federal Reserve Bank Inflation Calculator here: https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator
Interest Rate (Percent)	7	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	1,615	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	1,524,240	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		1,524,240	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	0.93		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	81.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	47.57	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	208.35	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.02		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	2,558,256	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	229.60	/hour	
Residence Time	1/V_{space}	0.00	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.3	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.1739	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	11,142.05	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	2,665	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	3,065	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	55.4	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	29	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	18	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	64	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	2,900	gallons (storage needed to store a 14 day reagent supply rounded to

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0944

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ =	141.55	kW
	where A = Bmw for utility boilers		

Cost Estimate

Total Capital Investment (TCI)

Engineering estimate of total installed cost, scaled to 2022 dollars using the Chemical Engineering Plant Cost Index

Total Capital Investment (TCI) =	**$46,602,852**	in 2022 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,306,296 in 2022 dollars
Indirect Annual Costs (IDAC) =	$4,405,180 in 2022 dollars
Total annual costs (TAC) = DAC + IDAC	$5,711,477 in 2022 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$233,014 in 2022 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$45,130 in 2022 dollars
Annual ***SCR*** Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$114,201 in 2022 dollars
Annual ***Tempering Air Fan*** Electricity Cost =		$121,967 in 2022 dollars
Lost Electrical Production Due to SCR =		$534,680
Annual Catalyst Replacement Cost =		$257,304 in 2022 dollars
Direct Annual Cost =		$1,306,296 in 2022 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$5,871 in 2022 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$4,399,309 in 2022 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$4,405,180 in 2022 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$5,711,477 per year in 2022 dollars
NOx Removed =	208 tons/year
Cost Effectiveness =	$27,413 per ton of NOx removed in 2022 dollars

Attachment I.1-2

Combustion Turbines CO/VOC Control Costs

Attachment I.1-2 Combustion Turbines CO/VOC Control Costs

Cost Estimate

Direct Costs			
Total Purchased equipment costs in 2022 dollars			
Equipment Costs (EC) for a Fixed Bed Catalytic Oxidizer + auxiliary equipment[a] (A) =	Pleasant Energy, LLC 2017 BACT x (CEPCI 2022/CEPCI 2017)	$5,727,260	in 2022 dollars
Instrumentation[b] =	0.10 × A =	$572,726	
Sales taxes =	0.03 × A =	$171,818	
Freight =	0.05 × A =	$286,363	
	Total Purchased equipment costs (B) =	$6,758,167	in 2022 dollars

Footnotes

a - Auxiliary equipment includes equipment (e.g., duct work) normally not included with unit furnished by incinerator vendor.

b - Includes the instrumentation and controls furnished by the incinerator vendor.

Direct Installation Costs in 2022 dollars			
Foundations and Supports =	0.08 × B =	$540,653	
Handling and Erection =	0.14 × B =	$946,143	
Electrical =	0.04 × B =	$270,327	
Piping =	0.02 × B =	$135,163	
Insulation for Ductwork =	0.01 × B =	$67,582	
Painting =	0.01 × B =	$67,582	
Site Preparation (SP) =		$0	
Buildings (Bldg) =		$0	
	Total Direct Installaton Costs =	$2,027,450	
Total Direct Costs (DC) =	ıase Equipment Costs (B) + Total Direct Installation Costs =	$8,785,617	in 2022 dollars

Total Indirect Installation Costs in 2022 dollars			
Engineering =	0.10 × B =	$675,817	
Construction and field expenses =	0.05 × B =	$337,908	
Contractor fees =	0.10 × B =	$675,817	
Start-up =	0.02 × B =	$135,163	
Performance test =	0.01 × B =	$67,582	
	Total Indirect Costs (IC) =	$1,892,287	in 2022 dollars
Continency Factor (CF) =	10%		
Continency Cost (C) =	CF(IC+DC)=	$1,067,790	
Total Capital Investment =	**DC + IC +C =**	**$11,745,694**	**in 2022 dollars**

Direct Annual Costs			
Catalyst Replacement Cost (cat. Cost)	Pleasant Energy, LLC 2017 BACT x (CEPCI 2022/CEPCI 2017)	$1,405,463	
Catalyst Disposal Cost	Assume 5% of Catalyst Cost	$70,273	
Interest Rate (i)		7%	
Catalyst Life (y)		4	years
Future worth Factor (FWF)	= $i\,[1/((1+i)^y - 1)]$	0.225	
Total Annual Catalyst Cost	= (Catalyst Replacement Cost + Disposal Cost)*FWF	$332,377	
Annual Electricity Cost	Electricity Price =	$0	**N/A FOR THIS APPLICATION**
Annual Fuel Costs for Natural Gas	hours/year	$0	**N/A FOR THIS APPLICATION**
Operating Labor	Operator = 0.5hours/shift × Labor Rate[$70.20] × (8760 Operating hours/8 hours/shift)	$38,435	
	Supervisor = 15% of Operator	$5,765	
Maintenance Costs	Labor = 0.5 hours/shift × Labor Rate[$70.20] × (8760 Operating Hours/8 hours/shift)	$38,435	
	Materials = 100% of maintenance labor	$38,435	
Direct Annual Costs (DC) =		**$453,446**	**in 2022 dollars**

Indirect Annual Costs			
Overhead	= 60% of sum of operating, supervisor, maintenance labor and maintenance materials	$72,641	
Administrative Charges	= 2% of TCI	$234,914	
Property Taxes	= 1% of TCI	$117,457	
Insurance	= 1% of TCI	$117,457	
Estimated Equipment Life (n)		20	years
Capital Recovery Factor (CRF)	= $(i\,(1+i)^n)/((1+i)^n - 1)$	0.0944	
Capital Recovery	= CRF[TCI-1.08(cat. Cost)]	$965,431	
Indirect Annual Costs (IC) =		**$1,507,920**	**in 2022 dollars**

Total Annual Cost =	**DC + IC =**	**$1,961,366**	**in 2022 dollars**

Cost Effectiveness

Cost Effectiveness = (Total Annual Cost)/(Annual Quantity of Pollutants Destroyed)

Total Annual Cost (TAC) =	$1,961,366	per year in 2022 dollars
VOC Pollutants Destroyed =*	73.1	tons/year
VOC Cost Effectiveness =	$26,837	Per ton of VOC removed in 2022 dollars
CO Pollutants Destroyed =*	186.5	tons/year
CO Cost Effectiveness =	$10,519	Per ton of CO removed in 2022 dollars

*Based on 95% control efficiency, uncontrolled VOC emission rate of 76.93 tpy, and uncontrolled CO emission rate of 196.28 tpy

Attachment I.1-3

GHG Control Costs

Attachment I.1-3 GHG Control Costs

Xcel Energy - Blue Lake
Attachment D.1-4 - CO2 CCS Costs
GHG Control Cost Summary - 430 Miles to the Nearest CO2 Industrial User

Emission Source	Control Eff %	Controlled Emissions T/y	Emission Reduction T/yr	Installed Capital Cost $Million	Annual Operating Cost $M/yr	Total Annual Cost[1] $M/yr	Pollution Control Cost $/ton
Facility-Wide GHG	**90%**	**196,806**	**1,771,251**	**$1,500**	**$6.1**	**$147**	**$83**

[1]Annual cost is based on the annualized total capital cost (assuming a 20-year equipment life and current prime bank rate as of 11/14/2022) plus the annual operating cost. Note that other indirect operating such as overhead, administration, property tax, and/or insurance are not accounted for as part of this cost estimate.

Xcel Energy - Blue Lake
Attachment D.1-4 - CO2 CCS Costs
Equipment and Pipeline Cost to Nearest Industrial User

CO_2 Capture Equipment Capital Cost - Combined Gas Turbines and Generators Emissions

Basis **NETL Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3, Updated Costs July 2015**

NETL Study Baseline Subcritical Coal-Fired Power Plant CO_2 Uncontrolled Emission Rate	977,858	lb/hr
Total Capital Costs for Subcritical Coal-Fired Power Plant without CO_2 Capture	$1,515	Million
Total Capital Costs for Subcritical Coal-Fired Power Plant with CO_2 Capture	$2,675	Million
Incremental Capital Cost for CO_2 Capture	$1,159.5	Million

GHG Emissions (CO_2)

Combustion Turbines Combined	449,328	lb/hr
New Engine Generators (Includes emissions from all 3 units)	49,620	lb/hr

Estimated Cost

Estimate = $1,159.5M*(498,948/977,858)^0.6	$774	Million

CO_2 Pipeline Capital Cost - Combined Gas Turbines and Generators Emissions

Basis **"FE/NETL CO2 Transport Cost Model (2018)" spreadsheet version 2b, real costs 2011$**

Pipeline Minimum Length	430	miles
Pipeline Diameter	16	inches
Materials Cost =	$118.8	Million
Labor Cost =	$282.3	Million
Right of Way =	$21.6	Million
Miscellaneous =	$95.5	Million
CO_2 Surge Tank =	$1.2	Million
Pipeline Control System =	$0.1	Million
Pumps =	$1.0	Million
Total CO_2 Pipeline Cost (2011$) =	$520.5	Million
Total CO_2 Pipeline Cost (2022$)[1] =	$725.5	Million

Total Costs $1,499.8 Million

1 Based on Chemical Engineering Plant Cost Indices for 2011 and 2022.

Xcel Energy - Blue Lake
Attachment D.1-4 - CO2 CCS Costs
Pipeline Operational Expenses to Nearest Industrial User

Approximate Annual O&M Costs of Carbon Capture and Transport[1]

Parameter	Value
CO_2 Production (tons)	2,185,392
CO_2 Capture Efficiency	90%
CO_2 Captured (tons)	1,966,853
Length of Pipeline + 25% Route Factor (mi)	430
Length of Pipeline (km)[2]	692

Operating Expenses

Pipeline O&M	$3.6
Pipeline related equipment and pumps O&M	$0.1
Electricity costs for pumps	$0.6
Total annual operating expenses (2011$)	$4.4
Total annual operating expenses (2022$)[2]	$6.1

1 This table is based on "FE/NETL CO2 Transport Cost Model (2018)" spreadsheet version 2b, Real Costs 2011$.

2 Based on Chemical Engineering Plant Cost Indices for 2011 and 2022.

Attachment I.2

RACT/BACT/LAER Clearinghouse Summary

Attachment I.2-1 Combustion Turbine RBLC
Attachment I.2-2 Engine Generator RBLC
Attachment I.2-3 Emergency Generator RBLC

Attachment I.2RACT/BACT/LAER Clearinghouse Summary

Attachment I.2-1

Combustion Turbine RBLC

Attachment I.2-1 Combustion Turbine RBLC

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0019	LB/MMBTU	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0019	LB/MMBTU	3-HR AVERAGE	BACT-PSD		0			0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	2 COMBUSTION TURBINES	NATURAL GAS	130	MW	Particulate matter, filterable (FPM)	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0033	LB/MMBTU	3-HOUR BLOCK AVERAGE	BACT-PSD		0			0		
IL-0121	INVENERGY NELSON EXPANSION LLC	INVENERGY	IL	15060042	221112	09/27/2016 ACT	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.	Two Simple Cycle Combustion Turbines	Natural Gas	190	MW	Particulate matter, filterable (FPM)	turbine design and good combustion practices	0.0038	LB/MMBTU	3-HOUR BLOCK AVERAGE	BACT-PSD		0.015	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
IL-0121	INVENERGY NELSON EXPANSION LLC	INVENERGY	IL	15060042	221112	09/27/2016 ACT	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.	Two Simple Cycle Combustion Turbines	Natural Gas	190	MW	Particulate matter, total < 10 Âµ (TPM10)	turbine design and good combustion practices	0.005	LB/MMBTU	3-HOUR BLOCK AVERAGE	BACT-PSD		0.02	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
IL-0121	INVENERGY NELSON EXPANSION LLC	INVENERGY	IL	15060042	221112	09/27/2016 ACT	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.	Two Simple Cycle Combustion Turbines	Natural Gas	190	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	turbine design and good combustion practices	0.005	LB/MMBTU	3-HOUR BLOCK AVERAGE	BACT-PSD		0.02	LB/MMBTU	3-HOUR BLOCK AVERAGE	0		
CA-1223	PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	CA	SD 11-01	221112	11/19/2012 ACT	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	300	MW	Particulate matter, total (TPM)	PUC-QUALITY NATURAL GAS	0.0065	LB/MMBTU (HHV)	AT LOADS OF 80% OR HIGHER	BACT-PSD		5.5	LB/H		0		
CA-1223	PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	CA	SD 11-01	221112	11/19/2012 ACT	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	300	MW	Particulate matter, total < 10 Âµ (TPM10)	PUC-QUALITY NATURAL GAS	0.0065	LB/MMBTU (HHV)	AT LOADS OF 80% OR HIGHER	BACT-PSD		5.5	LB/H		0		
CA-1223	PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	CA	SD 11-01	221112	11/19/2012 ACT	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	300	MW	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	PUC-QUALITY NATURAL GAS	0.0065	LB/MMBTU (HHV)	AT LOADS OF 80% OR HIGHER	BACT-PSD		5.5	LB/H		0		
IN-0264	MONTPELIER GENERATING STATION	AES OHIO GENERATION, LLC	IN	179-37209-00026	221112	01/06/2017 ACT	COMBUSTION TURBINES	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	NATURAL GAS	270.9	MMBTU/H	Particulate matter, filterable < 10 Âµ (FPM10)	USE NATURAL GAS AS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	0.0066	LB/MMBTU	3-HR AVG FOR NATURAL GAS	BACT-PSD		0.012	LB/MMBTU	3-HR AVG FOR FUEL OIL	0		
IN-0264	MONTPELIER GENERATING STATION	AES OHIO GENERATION, LLC	IN	179-37209-00026	221112	01/06/2017 ACT	COMBUSTION TURBINES	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	NATURAL GAS	270.9	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	NATURAL GAS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	0.0066	LB/MMBTU	3-HR AVG FOR NATURAL GAS	BACT-PSD		0.012	LB/MMBTU	3-HR AVG FOR FUEL OIL	0		
LA-0349	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	LA	PSD-LA-824	221210	07/10/2018 ACT	Propose a new facility to liquefy natural gas for export	Compressor Turbines (20)	natural gas	540	mm btu/hr	Particulate matter, total < 10 Âµ (TPM10)	Good Combustion Practices and Use of low sulfur facility fuel gas	0.0066	LB/MM BTU		BACT-PSD		0			0		
LA-0349	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	LA	PSD-LA-824	221210	07/10/2018 ACT	Propose a new facility to liquefy natural gas for export	Compressor Turbines (20)	natural gas	540	mm btu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good Combustion Practices and Use of low sulfur facility fuel gas	0.0066	LB/MM BTU		BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Particulate matter, total (TPM)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Particulate matter, total < 10 Âµ (TPM10)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Particulate matter, total (TPM)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Particulate matter, total < 10 Âµ (TPM10)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good Combustion Practices and burning clean fuels (NG)	0.007	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	2 COMBUSTION TURBINES	NATURAL GAS	130	MW	Particulate matter, filterable (FPM)	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.007	LB/MMBTU	3 STACK TEST RUN AVERAGE, EXCEPT SU/SD	BACT-PSD		300.8	LB/EVENT	FOR ALL STARTUPS	0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	2 COMBUSTION TURBINES	NATURAL GAS	130	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.007	LB/MMBTU	3 STACK TEST RUN AVERAGE, EXCEPT SU/SD	BACT-PSD		300.8	LB/EVENT	FOR ALL STARTUPS	0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 922 acres, including 902 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Six Simle Cycle Gas-Fired Turbines	Natural Gas	1113	MMBtu/hr	Particulate matter, total (TPM)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS	BACT-PSD		10	% OPACITY	6 CONSECUTIVE MINUTES	0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 922 acres, including 902 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Six Simle Cycle Gas-Fired Turbines	Natural Gas	1113	MMBtu/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS	BACT-PSD		10	% OPACITY	6 CONSECUTIVE MINUTES	0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 922 acres, including 902 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Six Simle Cycle Gas-Fired Turbines	Natural Gas	1113	MMBtu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS	BACT-PSD		10	% OPACITY	6 CONSECUTIVE MINUTES	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 922 acres, including 302 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Four Combined Cycle Gas-Fired Turbines	Natural Gas	384	MMBtu/hr	Particulate matter, total (TPM)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS	BACT-PSD		10	% OPACITY	6 CONSECUTIVE MINUTES	0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 922 acres, including 302 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Four Combined Cycle Gas-Fired Turbines	Natural Gas	384	MMBtu/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS	BACT-PSD		10	% OPACITY	6 CONSECUTIVE MINUTES	0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 922 acres, including 302 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Four Combined Cycle Gas-Fired Turbines	Natural Gas	384	MMBtu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and burning clean fuel (natural gas)	0.007	LB/MMBTU	3-HOURS	BACT-PSD		10	% OPACITY	6 CONSECUTIVE MINUTES	0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	TURBINE	NATURAL GAS	0		Particulate matter, filterable (FPM)	good combustion practices and the use of gaseous fuel	0.0075	LB/MMBTU		BACT-PSD		0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	TURBINE	NATURAL GAS	0		Particulate matter, filterable < 10 Âµ (FPM10)	good combustion practices and the use of gaseous fuel	0.0075	LB/MMBTU		BACT-PSD		0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	TURBINE	NATURAL GAS	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	good combustion practices and the use of gaseous fuel	0.0075	LB/MMBTU		BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	3-HR AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	3-HR AVERAGE	BACT-PSD		0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	Gas turbines (9 units)	natural gas	1069	mm btu/hr	Particulate matter, total < 10 Âµ (TPM10)	good combustion practices and fueled by natural gas	0.0076	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE	BACT-PSD		0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	Gas turbines (9 units)	natural gas	1069	mm btu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	good combustion practices and fueled by natural gas	0.0076	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE	BACT-PSD		0			0		
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	AL	701-0010	221112	09/21/2021 ACT	Electric Generating Facility	Three 229 MW Simple Cycle Combustion Turbines	Natural Gas	229	MW	Particulate matter, total < 10 Âµ (TPM10)		0.008	LB/MMBTU	3 HOUR AVG	BACT-PSD	SIP	18	LB/HR	3 HOUR AVG	0		
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	AL	701-0010	221112	09/21/2021 ACT	Electric Generating Facility	Three 229 MW Simple Cycle Combustion Turbines	Natural Gas	229	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.008	LB/MMBTU	3 HOUR AVG	BACT-PSD		18	LB/HR	3 HOUR AVG	0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines MSS	NATURAL GAS	0		Particulate matter, total (TPM)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR		BACT-PSD		0			0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines MSS	NATURAL GAS	0		Particulate matter, total < 10 Âµ (TPM10)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR		BACT-PSD		0			0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines MSS	NATURAL GAS	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR		BACT-PSD		0			0		
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	MI	191-12	221112	07/25/2013 ACT	Four (4) natural gas fired combined cycle combustion turbine generators (CTG) and heat recovery steam generators (HRSG) with duct burner firing capability; ancillary facility equipment.	TWO EACH): 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Particulate matter, filterable (FPM)	Efficient combustion; natural gas fuel.	0.01	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG. TIME.	BACT-PSD	N/A	0			0		
NY-0113	EDGEWOOD ENERGY LLC	EDGEWOOD ENERGY LLC	NY	1-4728-03244/00005	221112	07/09/2013 ACT	Edgewood Energy LLC is proposing to construct a simple cycle combustion turbine plant located in Edgewood, Suffolk County, New York that contains two GE LM6000 combustion turbines that fire only natural gas. The facility has an optimum electrical output of 95 megawatts (MW) firing only natural gas. This electrical output represents an increase from the 79.9 MW limit. This increase was	Turbines - NG	natural gas	0		Particulate matter, filterable (FPM)		0.0112	LB/MMBTU	1 H	BACT-PSD		0			0		
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	MI	191-12	221112	07/25/2013 ACT	Four (4) natural gas fired combined cycle combustion turbine generators (CTG) and heat recovery steam generators (HRSG) with duct burner firing capability; ancillary facility equipment.	TWO EACH): 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Efficient combustion; natural gas fuel.	0.02	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG. TIME	BACT-PSD	N/A	0			0		
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	MI	191-12	221112	07/25/2013 ACT	Four (4) natural gas fired combined cycle combustion turbine generators (CTG) and heat recovery steam generators (HRSG) with duct burner firing capability; ancillary facility equipment.	TWO EACH): 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Efficient combustion; natural gas fuel.	0.02	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG. TIME	BACT-PSD	N/A	0			0		
TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.72	LB/H	1 HOUR	BACT-PSD		0			0		
TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.72	LB/H	1 HOUR	BACT-PSD		0			0		
TX-0816	CORPUS CHRISTI LIQUEFACTION	CORPUS CHRISTI LIQUEFACTION STAGE III, LLC	TX	139479, PSDTX1496, GHGPSDTX157	221210	02/14/2017 ACT	trains 1 and 2 will consist of 12 natural gas compressor turbines, 4 thermal oxidizers, 2 sets of flares each comprised of one wet gas flare and one dry gas flare, 2 amine surge tanks (maintenance, startup, and shutdown [MSS] only), 3 diesel generators, 3 fire-water pump diesel engines, 6 fixed roof diesel storage tanks, and piping components.	Refrigeration compressor turbines	NATURAL GAS	40000	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.75	LB/H		BACT-PSD		0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
FL-0354	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-013-AC	221112	08/25/2015 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2100	MMBtu/hr (approx)	Particulate matter, total (TPM)	Clean fuel prevents PM formation	2	GR. S / 100 SCF GAS	FUEL RECORD KEEPING	BACT-PSD	SIP	0.0015	% S IN FUEL OIL	FUEL RECORD KEEPING	0		
FL-0354	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-013-AC	221112	08/25/2015 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2100	MMBtu/hr (approx)	Particulate matter, total < 10 Âµ (TPM10)	Clean fuel prevents PM formation	2	GR. S / 100 SCF	FUEL RECORD KEEPING	BACT-PSD	SIP	0.0015	% S IN ULSD	FUEL RECORD KEEPING	0		
FL-0354	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-013-AC	221112	08/25/2015 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2100	MMBtu/hr (approx)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Clean fuel prevents PM formation	2	GR. S / 100 SCF	FUEL RECORD KEEPING	BACT-PSD	SIP	0.0015	% S IN ULSD	FUEL RECORD KEEPING	0		
FL-0355	FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	FL	0710002-022-AC	221112	09/10/2015 ACT	Also includes 12 gas turbines (63 MW each) for peaking, introduced into service	Combustion Turbines	Natural gas	2262.4	MMBtu/hr gas	Particulate matter, total (TPM)	Use of clean fuels, and annual VE test	2	GR S / 100 SCF GAS	FOR NATURAL GAS	BACT-PSD		0.0015	% S IN ULSD	FOR ULSD	0		
FL-0355	FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	FL	0710002-022-AC	221112	09/10/2015 ACT	Also includes 12 gas turbines (63 MW each) for peaking, introduced into service	Combustion Turbines	Natural gas	2262.4	MMBtu/hr gas	Particulate matter, total < 10 Âµ (TPM10)	Use of clean fuels	2	GR S / 100 SCF GAS	FOR NATURAL GAS	BACT-PSD		0.0015	% S IN ULSD	FOR ULSD	0		
FL-0355	FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	FL	0710002-022-AC	221112	09/10/2015 ACT	Also includes 12 gas turbines (63 MW each) for peaking, introduced into service	Combustion Turbines	Natural gas	2262.4	MMBtu/hr gas	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of clean fuels	2	GR S / 100 SCF GAS	FOR NATURAL GAS	BACT-PSD		0.0015	% S IN ULSD	FOR ULSD	0		
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	PORT ARTHUR LNG, LLC	TX	131769, PSDTX1456, GHGPSDTX134	486210	02/17/2016 ACT	Liquefied natural gas (LNG) export terminal	Simple Cycle Electrical Generation Gas Turbines 15.210	natural gas	34	MW	Particulate matter, total < 10 Âµ (TPM10)	Equipment specifications & work practices - Good combustion practices and use of low carbon, low sulfur fuel	2.32	LB/H		BACT-PSD		8.84	T/YR		0		
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	PORT ARTHUR LNG, LLC	TX	131769, PSDTX1456, GHGPSDTX134	486210	02/17/2016 ACT	Liquefied natural gas (LNG) export terminal	Simple Cycle Electrical Generation Gas Turbines 15.210	natural gas	34	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Equipment specifications & work practices - Good combustion practices and use of low carbon, low sulfur fuel	2.32	LB/H		BACT-PSD		8.84	T/YR		0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	Particulate matter, total (TPM)	good combustion practices	4	LB/H	3-HOUR AVERAGE	BACT-PSD		17.5	TONS	CALENDAR YEAR	0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP04)	Natural Gas	40	MW	Particulate matter, total (TPM)	good combustion practices	4	LB/H	3-HOUR AVERAGE	BACT-PSD		17.5	TONS	CALENDAR YEAR	0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	Particulate matter, total (TPM)	good combustion practices	4	LB/H	3-HOUR AVERAGE	BACT-PSD		17.5	TONS	CALENDAR YEAR	0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Combustion of Fuel Gas, Good Combustion Practices Including Proper Burner Design.	4.5	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Combustion of Fuel Gas, Good Combustion Practices Including Proper Burner Design.	4.5	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	Natural gas	667	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	Natural gas	667	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas, inlet air conditioning and good combustion practices.	4.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Combustion of Fuel Gas, Good Combustion Practices Including Proper Burner Design.	4.5	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Combustion of Fuel Gas, Good Combustion Practices Including Proper Burner Design.	4.5	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
CO-0075	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	13PB2245	221112	05/30/2014 ACT	Power generation facility	Turbine - simple cycle gas	natural gas	375	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	4.8	LB/H	3-HR AVE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
CO-0075	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	13PB2245	221112	05/30/2014 ACT	Power generation facility	Turbine - simple cycle gas	natural gas	375	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas burned has total sulfur content less than 0.5 grains/100 SCF.	4.8	LB/H	3-HR AVE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
IN-0261	VERMILLION GENERATING STATION	DUKE ENERGY INDIANA, LLC VERMILLION GENERATING STA	IN	165-36956-00022	221112	02/28/2017 ACT	ELECTRIC UTILITY SERVICES	[illegible] NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	80	MW	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES	5	LB/H	EACH TURBINE	BACT-PSD		0.5	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IN-0261	VERMILLION GENERATING STATION	DUKE ENERGY INDIANA, LLC VERMILLION GENERATING STA	IN	165-36956-00022	221112	02/28/2017 ACT	ELECTRIC UTILITY SERVICES	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	80	MW	Particulate matter, filterable < 10 Âµ (FPM10)	GOOD COMBUSTION PRACTICES	5	LB/H	EACH TURBINE	BACT-PSD		0.5	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		
IN-0261	VERMILLION GENERATING STATION	DUKE ENERGY INDIANA, LLC VERMILLION GENERATING STA	IN	165-36956-00022	221112	02/28/2017 ACT	ELECTRIC UTILITY SERVICES	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	80	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES	5	LB/H	EACH TURBINE	BACT-PSD		0.5	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	PSC CASE NO. 9136	221119	07/01/2014 ACT	220 MEGAWATT SIMPLE CYCLE NATURAL GAS FIRED POWER PLANT ELEMENTS OF 220 MEGAWATT SIMPLE CYCLE NATURAL GAS FIRED POWER PLANT ELEMENTS OF 220 MW SIMPLE CYCLE PROJECT-WIDE EMISSION LIMITS: PM10 = 43.0 TONS/YR PM2.5 = 43.0 TONS/YR NOX = 58.5 TONS/YR	SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	NATURAL GAS	120	MW	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES AND USE OF NATURAL GAS	5	LB/H	3 STACK TEST RUNS	BACT-PSD		0.0079	LB/MMBTU	HIGH HEAT VALUE (HHV)	0		
ND-0030	LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	ND	PTC 13049	221112	09/16/2013 ACT	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.	Natural Gas Fired Simple Cycle Turbines	Natural gas	412	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)		5	LB/H	AVERAGE OF THREE TEST RUNS	BACT-PSD		0			0		
NJ-0086	BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	NJ	12863-BOP150001	221112	08/26/2016 ACT	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	Simple Cycle Stationary Turbines firing Natural gas	Natural Gas	2143980	MMBTU/YR	Particulate matter, filterable (FPM)	Use of Natural gas a clean burning fuel	5	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	OTHER CASE-BY-CASE	OPERATING PERMIT	0			0		
NJ-0086	BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	NJ	12863-BOP150001	221112	08/26/2016 ACT	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	Simple Cycle Stationary Turbines firing Natural gas	Natural Gas	2143980	MMBTU/YR	Particulate matter, total < 10 Âµ (TPM10)	Use of Natural gas a clean burning fuel	5	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	OTHER CASE-BY-CASE	OPERATING PERMIT	0			0		
NJ-0086	BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	NJ	12863-BOP150001	221112	08/26/2016 ACT	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	Simple Cycle Stationary Turbines firing Natural gas	Natural Gas	2143980	MMBTU/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of natural gas a clean burning fuel	5	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	OTHER CASE-BY-CASE	OPERATING PERMIT	0			0		
ND-0029	PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	ND	PTC 13037	221112	05/14/2013 ACT	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	Natural gas-fired turbines	Natural gas	451	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)		5.4	LB/H		BACT-PSD		0			0		
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE LM6000PC SPRINT Simple cycle combustion turbine	Pipeline quality natural gas	405.3	MMBTU/hr	Particulate matter, total < 10 Âµ (TPM10)	fire only pipeline quality natural gas	6	LB/HR	AT FULL OAD	BACT-PSD		0			0		
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE LM6000PC SPRINT Simple cycle combustion turbine	Pipeline quality natural gas	405.3	MMBTU/hr	Particulate matter, total (TPM)	fire only pipeline quality natural gas	6	LB/HR	AT FULL LOAD	BACT-PSD		0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	1.1	TONS/YR	ANNUAL AVERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	1.1	TONS/YR	ANNUAL AVERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	natural gas	2201	MM BTU/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	1.1	TONS/YR	ANNUAL AVERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	natural gas	2201	MM BTU/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	1.1	TONS/YR	ANNUAL AVERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 SU - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 SU - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 SU - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 SU - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 NO - Simple-Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices & use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and the use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT602 NO - Simple-Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	Natural Gas	2201	MM BTU/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices & use of low sulfur fuels (pipeline quality natural gas)	6.3	LB/HR	HOULY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
TX-0851	RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	TX	140792, PSDTX1498, GHGPSDTX158	486210	12/17/2018 ACT	Natural gas processing and liquefied natural gas (LNG) export terminal	Refrigeration Compression Turbines	NATL GAS	967	MMBTU/HR	Particulate matter, filterable < 10 Âµ (FPM10)	Good combustion practices and use of pipeline quality natural gas.	7	LB/HR		BACT-PSD	NSPS , NESHAP	0			0		
TX-0851	RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	TX	140792, PSDTX1498, GHGPSDTX158	486210	12/17/2018 ACT	Natural gas processing and liquefied natural gas (LNG) export terminal	Refrigeration Compression Turbines	NATL GAS	967	MMBTU/HR	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Good combustion practices and use of pipeline quality natural gas.	7	LB/HR		BACT-PSD	NSPS , NESHAP	0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
ND-0028	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	PTC13016	221112	02/22/2013 ACT	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.	Combustion Turbine	Natural gas	986	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Good Combustion Practices	7.3	LB/H	AVERAGE OF 3 TEST RUNS	BACT-PSD		0			0		
ND-0028	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	PTC13016	221112	02/22/2013 ACT	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.	Combustion Turbine	Natural gas	986	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	7.3	LB/H	AVERAGE OF THREE TEST RUNS	BACT-PSD		0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Combustion of Fuel Gas and Good Combustion Practices, Including Proper Burner Design.	8	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Combustion of Fuel Gas and Good Combustion Practices, Including Proper Burner Design.	8	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Particulate matter, total < 10 Âµ (TPM10)	Exclusive Combustion of Fuel Gas and Good Combustion Practices, Including Proper Burner Design.	8	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Particulate matter, total < 2.5 Âµ (TPM2.5)	Exclusive Combustion of Fuel Gas and Good Combustion Practices, Including Proper Burner Design.	8	LB/H	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Particulate matter, total (TPM)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR		BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR		BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR		BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Particulate matter, total (TPM)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR		BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR		BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices	8.5	T/YR		BACT-PSD		0			0		
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	TX	121051 AND PSDTX1418	221112	10/27/2015 ACT	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturer's output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Particulate matter, total < 10 Âµ (TPM10)	Pipeline Quality Natural Gas	8.6	LB/H		BACT-PSD		0			0		
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	TX	121051 AND PSDTX1418	221112	10/27/2015 ACT	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturer's output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline Quality Natural Gas	8.6	LB/H		BACT-PSD		0			0		
TX-0777	UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	TX	120973 AND PSDTX1420	221112	12/09/2015 ACT	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturer's output at baseload, ISO at 183 MW), operating as peaking units in simple cycle	Simple Cycle Turbine	natural gas	183	MW	Particulate matter, total < 10 Âµ (TPM10)	pipeline quality natural gas, good combustion practices	8.6	LB/H		BACT-PSD		0			0		
TX-0777	UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	TX	120973 AND PSDTX1420	221112	12/09/2015 ACT	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturer's output at baseload, ISO at 183 MW), operating as peaking units in simple cycle	Simple Cycle Turbine	natural gas	183	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	pipeline quality natural gas, good combustion practices	8.6	LB/H		BACT-PSD		0			0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS 100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Utilize only natural gas or ULSD fuel; Limit the time in startup or shutdown.	9.1	LB/H TOTAL PM	6-HR AVERAGE ON NG	BACT-PSD		22.7	LB/H TOTAL PM	6-HR AVERAGE ON ULSD	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS 100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Utilize only natural gas or ULSD fuel; Limit the time in startup or shutdown.	9.1	LB/H TOTAL PM	6-HR AVERAGE ON NG	BACT-PSD		22.7	LB/H TOTAL PM	6-HR AVERAGE ON ULSD	0		
VA-0326	DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	VA	51018	221112	10/04/2016 ACT	The facility is currently composed of four identical units (Model V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The	Two (2) GE 7FA simple cycle combustion turbines	Natural Gas	1961	MMBTU/HR	Particulate matter, filterable (FPM)	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	10	LB	H/12 MO ROLLING TOTAL	BACT-PSD		12.5	T	Y/12 MO ROLLING TOTAL	0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines	natural gas	920	MW	Particulate matter, filterable (FPM)	Use of pipeline quality natural gas and good combustion practices.	11.81	TON/YR		BACT-PSD	NSPS	0			0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines	natural gas	920	MW	Particulate matter, total < 10 Âµ (TPM10)	Use of pipeline quality natural gas and good combustion practices.	11.81	TON/YR		BACT-PSD	NSPS	0			0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines	natural gas	920	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of pipeline quality natural gas and good combustion practices.	11.81	TON/YR		BACT-PSD	NSPS	0			0		
VA-0326	DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	VA	51018	221112	10/04/2016 ACT	The facility is currently composed of four identical units (Model V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The	Two (2) GE 7FA simple cycle combustion turbines	Natural Gas	1961	MMBTU/HR	Particulate matter, filterable < 10 Âµ (FPM10)	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	12	LB	H/12 MO ROLLING TOTAL	BACT-PSD		15	T	Y/12 MO ROLLING TOTAL	0		
VA-0326	DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	VA	51018	221112	10/04/2016 ACT	The facility is currently composed of four identical units (Model V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The	Two (2) GE 7FA simple cycle combustion turbines	Natural Gas	1961	MMBTU/HR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion, operation and maintenance practices and use of pipeline quality natural gas	12	LB	H/12 MO ROLLING TOTAL	BACT-PSD		15	T	YR/12 MO ROLLING TOTAL	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	TX	77679, PSDTX1061M1 & O-3455	221112	10/14/2015 ACT	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).	Natural Gas Simple Cycle Turbine (>25 MW)	natural gas	232	MW	Particulate matter, total (TPM)	Pipeline quality natural gas; limited hours; good combustion practices.	12.09	LB/HR		BACT-PSD		12.94	TPY		0		
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	TX	77679, PSDTX1061M1 & O-3455	221112	10/14/2015 ACT	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).	Natural Gas Simple Cycle Turbine (>25 MW)	natural gas	232	MW	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices.	12.09	LB/HR		BACT-PSD		12.94	TPY		0		
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	TX	77679, PSDTX1061M1 & O-3455	221112	10/14/2015 ACT	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).	Natural Gas Simple Cycle Turbine (>25 MW)	natural gas	232	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices.	12.09	LB/HR		BACT-PSD		12.94	TPY		0		
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	TX	122401, PSDTX1428, GHGPSDTX111	221112	03/24/2016 ACT	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.	Large Combustion Turbines > 25 MW	natural gas	232	MW	Particulate matter, total < 10 Âµ (TPM10)	good combustion practices, low sulfur fuel	13.4	LB/H		BACT-PSD	NSPS	0			0		
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	TX	122401, PSDTX1428, GHGPSDTX111	221112	03/24/2016 ACT	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.	Large Combustion Turbines > 25 MW	natural gas	232	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	good combustion practices, low sulfur fuel	13.4	LB/H		BACT-PSD	NSPS	0			0		
TX-0794	HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	TX	130051,PSDTX1450, GHGPSDTX131	221112	04/07/2016 ACT	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).	Simple cycle turbine	natural gas	171	MW	Particulate matter, total < 10 Âµ (TPM10)	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	14	LB/H		BACT-PSD		0			0		
TX-0794	HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	TX	130051,PSDTX1450, GHGPSDTX131	221112	04/07/2016 ACT	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).	Simple cycle turbine	natural gas	171	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	14	LB/H		BACT-PSD		0			0		
WV-0026	WAVERLY FACILITY	PLEASANTS ENERGY, LLC	WV	R14-0034	221112	01/23/2017 ACT	300 MW, natural gas fired, simple cycle peaking power facility	GE Model 7FA Turbine	Natural Gas	1571	mmbtu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Inlet Air Filtration, Use of Natural Gas, Ultra-Low Sulfur Diesel	15	LB/HR	NATURAL GAS	BACT-PSD		39	LB/HR	FUEL OIL	15	LB/HR	NATURAL GAS
WV-0028	WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	WV	R14-0034A	221112	03/13/2018 ACT	300 MW Sinple-Cycle Peaking Plant	GE 7FA.004 Turbine	Natural Gas	167.8	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Inlet air filtration.	15.09	LB/HR		BACT-PSD		41.65	TONS/YEAR		15.09	LB/HR	
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE 7FA Simple Cycle Combustion Turbine	Pipeline quality natural gas	1780	MMBTU/HR	Particulate matter, total < 10 Âµ (TPM10)	will fire only pipeline quality natural gas	18	LB/HR		BACT-PSD		0			0		
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE 7FA Simple Cycle Combustion Turbine	Pipeline quality natural gas	1780	MMBTU/HR	Particulate matter, total (TPM)	will fire only pipeline quality natural gas	18	LB/HR		BACT-PSD		0			0		
TX-0826	MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	72579, PSDTX1080M1, GHGPSDTX13	221112	08/16/2017 ACT	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.	Simple Cycle Turbine	NATURAL GAS	162.8	MW	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas and good combustion practices	27	T/YR		BACT-PSD	MACT , NSPS	0			0		
TX-0826	MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	72579, PSDTX1080M1, GHGPSDTX13	221112	08/16/2017 ACT	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.	Simple Cycle Turbine	NATURAL GAS	162.8	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas and good combustion practices	27	T/YR		BACT-PSD	NSPS , MACT	0			0		
TX-0768	SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	TX	PSDTX1442, 125963	221112	10/09/2015 ACT	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.	Simple cycle turbines greater than 25 megawatts (MW)	natural gas	230	MW	Particulate matter, total < 10 Âµ (TPM10)	Pipeline quality natural gas; limited hours; good combustion practices.	84.1	LB/HR		BACT-PSD	NSPS	152.96	TPY		0		
TX-0768	SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	TX	PSDTX1442, 125963	221112	10/09/2015 ACT	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.	Simple cycle turbines greater than 25 megawatts (MW)	natural gas	230	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Pipeline quality natural gas; limited hours; good combustion practices.	84.1	LB/HR		BACT-PSD	NSPS	152.96	TPY		0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

NO_x

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of	Six Simle Cycle Gas-Fired Turbines	Natural Gas	1113	MMBtu/hr	Nitrogen Oxides (NOx)	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS	BACT-PSD	NSPS	0			0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of	Four Combined Cycle Gas-Fired Turbines	Natural Gas	384	MMBtu/hr	Nitrogen Oxides (NOx)	SCR, DLN combustors, and good combustion practices	2	PPMV @ 15% O2	3-HOURS	BACT-PSD	NSPS	0			0		
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	TX	N284, PSDTX1090M1, GHGPSDTX199	221112	08/27/2021 ACT	a new natural gas simple cycle turbine along with ancillary equipment.	Simple Cycle Turbine	natural gas	230	MW	Nitrogen Oxides (NOx)	Dry Low NOx Burners and SCR	2.5	PPMVD		BACT-PSD	NSPS , MACT	0			0		
CA-1223	PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	CA	SD 11-01	221112	11/19/2012 ACT	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	300	MW	Nitrogen Oxides (NOx)	WATER INJECTION, SCR	2.5	PPMVD	@15% O2, 1-HR AVG	BACT-PSD		8.18	LB/H	1-HR AVG	0		
CA-1238	PUENTE POWER		CA	00013-370	221112	10/13/2016 ACT	Utility	Gas turbine	Natural gas	262	MW	Nitrogen Oxides (NOx)		2.5	PPMVD	1 HOUR@15%O2	OTHER CASE-BY-CASE		0			0		
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	PSC CASE NO. 9136	221119	07/01/2014 ACT	120 MEGAWATT SIMPLE CYCLE NATURAL GAS FIRED POWER PLANTPERRYMAN 6 PROJECT-WIDE EMISSION LIMITS: PM10 = 43.0 TONS/YR PM2.5 = 43.0 TONS/YR NOX = 58.5 TONS/YR	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	NATURAL GAS	120	MW	Nitrogen Oxides (NOx)	USE OF NATURAL GAS, WATER/STEAM INJECTION, AND A SELECTIVE CATAYTIC REDUCTION (SCR) SYSTEM	2.5	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	LAER		5.8	LB/H	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	130 MEGAWATT NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	2 COMBUSTION TURBINES	NATURAL GAS	130	MW	Nitrogen Oxides (NOx)	USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN (DLN1), USE OF FACILITY PROCESS FUEL GAS AND PIPELINE NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2.5	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	LAER		1304.5	LB/EVENT	FOR ALL STARTUPS	0		
NJ-0086	BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	NJ	12863-BOP150001	221112	08/26/2016 ACT	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	Simple Cycle Stationary Turbines firing Natural gas	Natural Gas	2143980	MMBTU/YR	Nitrogen Oxides (NOx)	Selective Catalytic Reduction, water injection, use of natural gas a low NOx emitting fuel	2.5	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK AV	LAER	NSPS , OPERATING PERMIT	5.92	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Nitrogen Oxides (NOx)	GE LMS100 - Dilute water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown;	2.5	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG	BACT-PSD		3.8	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON ULSD	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Nitrogen Oxides (NOx)	GE LMS100 - Dilute water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown;	2.5	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG	BACT-PSD		3.8	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON ULSD	0		
*LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	LA	PSD-LA-838	486210	09/03/2020 ACT	A greenfield facility to liquefy and export natural gas.	Turbines (EQT0020 - EQT0031)	Natural gas	0		Nitrogen Oxides (NOx)	LNB + SCR	3.1	PPMVD @15%O2	3-HOUR AVERAGE	BACT-PSD		0			0		
LA-0349	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	LA	PSD-LA-824	221210	07/10/2018 ACT	Propose a new facility to liquefy natural gas for export	Compressor Turbines (20)	natural gas	540	mm btu/hr	Nitrogen Oxides (NOx)	DLN and SCR	5	PPMVD	@ 15% O2	BACT-PSD		0			0		
ND-0029	PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	ND	PTC 13037	221112	05/14/2013 ACT	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	Natural gas-fired turbines	Natural gas	451	MMBTU/H	Nitrogen Oxides (NOx)	Water injection plus SCR	5	PPPMVD	4 HR. ROLLING AVERAGE EXCEPT FOR STARTUP	BACT-PSD	NSPS	19	LB/H	DURING STARTUP	0		
ND-0030	LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	ND	PTC 13049	221112	09/16/2013 ACT	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.	Natural Gas Fired Simple Cycle Turbines	Natural gas	412	MMBTU/H	Nitrogen Oxides (NOx)	SCR	5	PPMVD	4 HOUR ROLLING AVERAGE EXCEPT STARTUP	BACT-PSD	NSPS	18.5	LB	TOTAL FOR 30 MINUTES DURING STARTUP	0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	Nitrogen Oxides (NOx)	SCR	5	PPMV AT 15% O2	1-HOUR	BACT-PSD	NSPS	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Trubine (EP04)	Natural Gas	40	MW	Nitrogen Oxides (NOx)	SCR	5	PPMV AT 15% O2	1-HOUR AVERAGE	BACT-PSD	NSPS	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	Nitrogen Oxides (NOx)	SCR	5	PPMV AT 15% O2	1-HOUR	BACT-PSD	NSPS	7.7	LB/H	30-DAY ROLLING AVERAGE	36	T/YR	
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	PORT ARTHUR LNG, LLC	TX	131769, PSDTX1456, GHGPSDTX134	486210	02/17/2016 ACT	Liquefied natural gas (LNG) export terminal	Simple Cycle Electrical Generation Gas Turbines 15.210	natural gas	34	MW	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION	5	PPM	ROLLING 24-HR AVERAGE	BACT-PSD	NSPS	0			0		
IL-0121	INVENERGY NELSON EXPANSION LLC	INVENERGY	IL	15060042	221112	09/27/2016 ACT	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.	Two Simple Cycle Combustion Turbines	Natural Gas	190	MW	Nitrogen Oxides (NOx)	Dry low-NOx combustion technology for natural gas and low-NOx combustion technology and water injection for ULSD.	0.033	LB/MMBTU		BACT-PSD	NSPS	0.164	LB/MMBTU		0		
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	AL	701-0010	221112	09/21/2021 ACT	Electric Generating Facility	Three 229 MW Simple Cycle Combustion Turbines	Natural Gas	229	MW	Nitrogen Oxides (NOx)		9	PPMVD	3 HOUR AVG @ 15% O2	BACT-PSD	NSPS , SIP	380	TONS	12 MONTH	0		
FL-0346	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-011-AC	221112	04/22/2014 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2000	MMBtu/hr (approx)	Nitrogen Oxides (NOx)	Required to employ dry low-NOx technology and wet injection. Water injection must be used when firing ULSD.	9	PPMVD @ 15% 02	24-HR BLOCK AVG, BY CEMS (NAT GAS)	BACT-PSD	NSPS	77	LB/H	24-HR BLOCK, BY CEMS (NAT GAS)	0		
FL-0354	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-013-AC	221112	08/25/2015 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2100	MMBtu/hr (approx)	Nitrogen Oxides (NOx)	Dry-low-NOx combustion system. Wet injection when firing ULSD.	9	PPMVD@15%O2	24-HR BLOCK AVERAGE	BACT-PSD	NSPS	42	PPMVD@15%O2	4-HR ROLLING	0		
FL-0355	FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	FL	0710002-022-AC	221112	09/10/2015 ACT	Electric power plant, consists of a 6-on-2 combined cycle unit (Units 2A through 2F) and two modern simple-cycle combustion turbines. Primary fuel is natural gas. Also includes 12 gas turbines (63 MW each) for peaking, introduced into service	Combustion Turbines	Natural gas	2262.4	MMBtu/hr gas	Nitrogen Oxides (NOx)	DLN and wet injection (for ULSD operation)	9	PPMVD@15% O2	GAS FIRING, 24-HR BLOCK AVG	BACT-PSD	NSPS	42	PPMVD@15% O2	ULSD FIRING, 4-HR ROLLING AVG	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

NO_x

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE LM6000PC SPRINT Simple cycle combustion turbine	Pipeline quality natural gas	405.3	MMBTU/hr	Nitrogen Dioxide (NO2)	dry low NOx burners and fire only pipeline natural gas	9	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2	BACT-PSD		0			0		
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE 7FA Simple Cycle Combustion Turbine	Pipeline quality natural gas	1780	MMBTU/HR	Nitrogen Oxides (NOx)	dry low NOx burners and fire only pipeline natural gas	9	PPMDV	24-HR ROLLING AVE, CORRECTED TO 15% O2	BACT-PSD		0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	EPN GU1 NO - Simple Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	Natural Gas	2201	MM BTU/hr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD @15%O2	30-DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	73.08	LB/HR	HOURLY MAXIMUM	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	EPN GU2 NO - Simple Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	Natural Gas	2201	MM BTU/hr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	9	PPMVD @15%O2	30-DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	73.08	LB/HR	HOURLY MAXIMUM	0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Nitrogen Oxides (NOx)	Dry Low NOx Combustor Design, Good Combustion Practices, and Natural Gas Combustion.	9	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
ND-0028	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	PTC13016	221112	02/22/2013 ACT	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.	Combustion Turbine	Natural gas	986	MMBTU/H	Nitrogen Oxides (NOx)	Dry low-NOx combustion (DLN)	9	PPMVD @15% OYYGEN	4 H.R.A. WHEN > 50MWE AND > 0 DEGREES F	BACT-PSD	NSPS	96	PPMVD @15% OXYGEN	4 H.R.A. WHEN < 50 MWE OR < 0 DEGREES F	399	LB/H	1 HOUR AVG./ANY TIME
TX-0686	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	109148, PSDTX1358	221112	04/22/2014 ACT	GSEC is proposing to build three additional new CTGs at the existing Antelope Elk Energy Center. The new facility will provide primarily peaking and intermediate power needs. The new units will be GE 7FS-Series gas turbines in simple cycle application, rated at 202 MW. Each turbine will operate a maximum of 4,572 hours per year.	Combustion Turbine Generator(CTG)	Natural Gas	202	MW	Nitrogen Oxides (NOx)	DLN	9	PPM	15% O2, 3 HR. ROLLING AVG.	BACT-PSD		0			0		
TX-0688	SR BERTRON ELECTRIC GENERATION STATION	NRG TEXAS POWER	TX	102731, PSDTX1294	221112	12/19/2014 ACT	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy	Simple cycle natural gas turbines	Natural Gas	225	MW	Nitrogen Oxides (NOx)	DLN	9	PPM	3HR ROLLING AVG.	BACT-PSD		0			0		
TX-0690	CEDAR BAYOU ELECTRIC GERNERATION STATION	NRG TEXAS POWER	TX	105810, PSDTX1308	221112	09/12/2012 ACT	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy	Simple Cycle Combustion Turbines	Natural Gas	225	MW	Nitrogen Oxides (NOx)	DLN	9	PPM	3HR. ROLLING AVG.	BACT-PSD		0			0		
TX-0693	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE INC	TX	109148 PSDTX1358	221112	04/22/2014 ACT	Golden Spread Electric Cooperative (GSEC) currently owns and operates Antelope Station (now renamed Antelope Elk Energy Center), a 168 MW generating facility made up of 18 quick start WÄrtsilÄ¤ engines. GSEC is proposing to build a new combustion turbine-generator (CTG) facility at Antelope Station, while the 18 WÄrtsilÄ¤ engines will remain and continue to be authorized by TCEQ Standard	combustion turbine	natural gas	202	MW	Nitrogen Oxides (NOx)	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVERAGE	BACT-PSD		0			0		
TX-0694	INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	TX	111724 PSDTX1374	221112	02/02/2015 ACT	Indeck Wharton, L.L.C. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode.	(3) combustion turbines	natural gas	220	MW	Nitrogen Oxides (NOx)	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVERAGE	BACT-PSD		0			0		
TX-0695	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	110423 PSDTX1366	221112	08/01/2014 ACT	The proposed project is to construct and operate two natural gas-fired simple-cycle combustion turbine generators (CTGs) at the Ector County Energy Center (ECEC), located approximately 20 miles northwest of Odessa, Texas, in Ector County.	(2) combustion turbines	natural gas	180	MW	Nitrogen Oxides (NOx)	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVG	BACT-PSD		0			0		
TX-0696	ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	TX	114698 PSDTX1378	221112	09/22/2014 ACT	The proposed project is to construct and operate the RPGS comprised of three new simple cycle combustion turbine generators (CTG), fueled by pipeline quality natural gas. The new CTGs will be peaking units, designed to operate during periods of high electric demand. The three CTGs will produce between 507 and 694 MW of electricity combined, depending on ambient temperature and the	(2) simple cycle turbines	natural gas	600	MW	Nitrogen Oxides (NOx)	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVG	BACT-PSD		0			0		
TX-0701	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	110423, PSDTX1366	221112	05/13/2013 ACT	The proposed project is for two natural gas fired simple cycle CTGs. The proposed models include GE7Fa.03 and GE7Fa.05. They have an output of 165-193 MW. The new CTGs will operate as peaking units and will be limited to 2500 hours per year of operation each.	Simple Cycle Combustion Turbines	natural gas	180	MW	Nitrogen Oxides (NOx)	Dry low NOx combustor	9	PPMVD	15%O2, 3HR ROLLING BASIS	BACT-PSD		0			0		
TX-0733	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	109148, PSDTX1358M1	221112	05/12/2015 ACT	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7FS-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.	Simple Cycle Turbine & Generator	natural gas	202	MW	Nitrogen Oxides (NOx)	Dry Low NOx burners	9	PPMVD AT 15% O2		BACT-PSD		0			0		
TX-0734	CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	TX	120849 AND PSDTX1414	221112	05/08/2015 ACT	Navasota South Peakers Operating Company II LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Nitrogen Oxides (NOx)	dry low-NOx (DLN) burners	9	PPMVD @ 15% O2	3-HR AVERAGE	BACT-PSD	NSPS	0			0		
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	TX	77679, PSDTX1061M1 & O-3455	221112	10/14/2015 ACT	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).	Natural Gas Simple Cycle Turbine (>25 MW)	natural gas	232	MW	Nitrogen Oxides (NOx)	Dry Low NOx burners, good combustion practices, limited operations	9	PPMVD @ 15% O2		BACT-PSD	NSPS	0			0		
TX-0768	SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	TX	PSDTX1442, 125963	221112	10/09/2015 ACT	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.	Simple cycle turbines greater than 25 megawatts (MW)	natural gas	230	MW	Nitrogen Oxides (NOx)	Dry Low NOx burners	9	PPMVD @ 15% O2		BACT-PSD	NSPS	0			0		
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	TX	121051 AND PSDTX1418	221112	10/27/2015 ACT	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Nitrogen Oxides (NOx)	DLN burners	9	PPMVD @ 15% O2	3-HR AVERAGE	BACT-PSD	NSPS	0			0		
TX-0777	UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	TX	120973 AND PSDTX1420	221112	12/09/2015 ACT	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle	Simple Cycle Turbine	natural gas	183	MW	Nitrogen Oxides (NOx)	dry low NOX burners	9	PPMVD @ 15% O2	3-HR ROLLING AVERAGE PEAK	BACT-PSD	NSPS	0			0		
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	TX	122401, PSDTX1428, GHGPSDTX111	221112	03/24/2016 ACT	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.	Large Combustion Turbines > 25 MW	natural gas	232	MW	Nitrogen Oxides (NOx)	Dry low-NOx burners (DLN), good combustion practices	9	PPM		BACT-PSD	NSPS	0			0		
TX-0794	HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	TX	130051,PSDTX1450, GHGPSDTX131	221112	04/07/2016 ACT	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).	Simple cycle turbine	natural gas	171	MW	Nitrogen Oxides (NOx)	emission controls consist of dry low-NOx combustors (DLN). DLN combustors use two stages of combustion, transitioning from initial startup with fuel and flame in the primary nozzles only, through a lean lean stage with fuel and flame in the primary and secondary	9	PPMVD @ 15% O2	3-HR ROLLING AVERAGE	BACT-PSD	NSPS	0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Nitrogen Oxides (NOx)	Dry Low NOx burners (control), natural gas, good combustion practices, limited operating hours (prevention)	9	PPMV	15% O2 3-H AVG	BACT-PSD	NSPS	0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0826	MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	72579, PSDTX1080M1, GHGPSDTX13	221112	08/16/2017 ACT	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.	Simple Cycle Turbine	NATURAL GAS	162.8	MW	Nitrogen Oxides (NOx)	Dry low-NOx burners	9	PPMVD		BACT-PSD	NSPS , MACT	0			0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines	natural gas	920	MW	Nitrogen Oxides (NOx)	Dry low NOx burners	9	PPMVD		BACT-PSD	NSPS	0			0		
TX-0851	RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	TX	140792, PSDTX1498, GHGPSDTX158	486210	12/17/2018 ACT	Natural gas processing and liquefied natural gas (LNG) export terminal	Refrigeration Compression Turbines	NATL GAS	967	MMBTU/HR	Nitrogen Oxides (NOx)	Dry Low NOx burners. Good combustion practices	9	PPMVD	15% O2	BACT-PSD	NSPS , NESHAP	0			0		
TX-0900	ECTOR COUNTY ENERGY CENTER	ECTOR COUNTY ENERGY CENTER LLC	TX	110423, PSDTX1366M1 GHGPSD49M1	221112	08/17/2020 ACT	increase the hours of operation for the two simple cycle gas turbines	Simple Cycle Turbines	natural gas	0		Nitrogen Oxides (NOx)	Equipped with dry low NOx burners with best management practices and good combustion practices. Minimize the duration of startup and shutdown events to less than 60 minutes per event. Limit MSS	9	PPMVD	3% O2 3 HR AVG	BACT-PSD	NSPS , MACT , SIP	15	PPMVD	PEAK 3% O2 1 HR AVG	0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	TURBINE	NATURAL GAS	0		Nitrogen Oxides (NOx)	LOW NOX BURNERS AND SCR	9	PPMVD	15% O2	BACT-PSD		0			0		
VA-0326	DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	VA	51018	221112	10/04/2016 ACT	The facility is currently composed of four Kraftwerk Unity Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The	Two (2) GE 7FA simple cycle combustion turbines	Natural Gas	1961	MMBTU/HR	Nitrogen Oxides (NOx)	Low NOx Burners/Combustion Technology	9	PPM	VD/12 MO ROLLING TOTAL	BACT-PSD		74.2	LB	H/12 MO ROLLING TOTAL	0		
WV-0026	WAVERLY FACILITY	PLEASANTS ENERGY, LLC	WV	R14-0034	221112	01/23/2017 ACT	300 MW, natural gas fired, simple cycle peaking power facility	GE Model 7FA Turbine	Natural Gas	1571	mmbtu/hr	Nitrogen Oxides (NOx)	Dry Low-NOx Combustion System (DLNB), Water injection	9	PPM	NATURAL GAS	BACT-PSD	NSPS	49	PPM	FUEL OIL	9	PPM	NATURAL GAS
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Nitrogen Oxides (NOx)	Dry Low NOx Combustor Design, Good Combustion Practices, and Natural Gas Combustion.	9	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	Construction of (3) GE 7HA.03 natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Nitrogen Oxides (NOx)	Dry Low NOx burners (control), natural gas, good combustion practices, limited operating hours (prevention)	9	PPMV	15% O2 3-H AVG	BACT-PSD	NSPS	0			0		
WV-0028	WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	WV	R14-0034A	221112	03/13/2018 ACT	300 MW Sinple-Cycle Peaking Plant	GE 7FA.004 Turbine	Natural Gas	167.8	MW	Nitrogen Oxides (NOx)	Dry LNB	69	LB/HR		BACT-PSD	NSPS	232.3	TONS/YEAR		9	PPM	
NY-0106	GREENIDGE STATION	GREENIDGE GENERATION LLC	NY	8-5736-00004/00017	221112	09/07/2016 ACT	Greenidge Generation LLC has submitted a revised application for a Title V Air Permit in accordance with the requirements of Title 6 of the New York compilation of Codes, Rules, and Regulations, Part 201-6 (6 NYCRR Part 201-6). The application is for conversion of the Greenidge Electricity Generating Station, located in the Town of Torrey, Yates County to operate primarily on natural gas	Turbine - natural gas	natural gas	107	MW	Nitrogen Oxides (NOx)	Advanced low NOx burners, closed-coupled and staged over-fire air, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction.	0.03	LB/MMBTU	12 MO	LAER		0.0365	LB/MMBTU	1 H	0		
NY-0106	GREENIDGE STATION	GREENIDGE GENERATION LLC	NY	8-5736-00004/00017	221112	09/07/2016 ACT	Greenidge Generation LLC has submitted a revised application for a Title V Air Permit in accordance with the requirements of Title 6 of the New York compilation of Codes, Rules, and Regulations, Part 201-6 (6 NYCRR Part 201-6). The application is for conversion of the Greenidge Electricity Generating Station, located in the Town of Torrey, Yates County to operate primarily on natural gas	Turbine - natural gas and wood	natural gas and up to 19% wood	107	MW	Nitrogen Oxides (NOx)	Advanced low NOx burners, closed-coupled and staged over-fire air, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction.	0.03	LB/MMBTU	12 MO	LAER		0.058	LB/MMBTU	1 H	0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Nitrogen Oxides (NOx)	DLN combustors and Good Combustion Practices	15	PPMV @ 15% O2	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Nitrogen Oxides (NOx)	DLN combustors and Good Combustion Practices	15	PPMV @ 15% O2	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	Gas turbines (9 units)	natural gas	1069	mm btu/hr	Nitrogen Oxides (NOx)	good combustion practices and dry low nox burners	15	PPMVD	@15%O2	BACT-PSD		0			0		
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	108182 PSDTX1346	221112	05/20/2014 ACT	NRG proposes to construct six natural gas-fired simple cycle combustion turbine generators (CTG) for peaking, designed to operate during periods of high electric demand. The six CTGs selected by NRG are General Electric Frame 7E turbines have an ISO rating of 65 MW and a nominal maximum generating capacity of 80 MW. Each of the turbines will not exceed 20 percent annual capacity (equivalent	(6) simple cycle turbines	natural gas	65	MW	Nitrogen Oxides (NOx)	DLN combustors	15	PPMVD	@15% O2, 3-HR ROLLING AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Nitrogen Oxides (NOx)	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXYGEN	3-HR AVERAGE AT > 50% PEAK LOAD	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Nitrogen Oxides (NOx)	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXYGEN	3-HR AVERAGE AT > 50% PEAK LOAD	BACT-PSD		0			0		
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	MI	191-12	221112	07/25/2013 ACT	Four (4) natural gas fired combined cycle combustion turbine generators (CTG) and heat recovery steam generators (HRSG) with duct burner firing capability; ancillary facility equipment.	EUCTGSC1- 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Nitrogen Oxides (NOx)	Dry low-NOx combustors	0.09	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG. TIME.	BACT-PSD	N/A	0			0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Nitrogen Oxides (NOx)	DLNB and good combustion practices.	25	PPM	4-HR ROLL AVG EXCEPT LESS THAN 75% PEAK	BACT-PSD	NSPS , SIP	60	LB/H	24-HR ROLL AVG EXCEPT SS	0		
IN-0264	MONTPELIER GENERATING STATION	AES OHIO GENERATION, LLC	IN	179-37209-00026	221112	01/06/2017 ACT	COMBUSTION TURBINES	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	NATURAL GAS	270.9	MMBTU/H	Nitrogen Oxides (NOx)	WATER INJECTION	25	PPMV	AT 15% O2 FOR NATURAL GAS	BACT-PSD		42	PPMV	AT 15% O2 FOR FUEL OIL	0		
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE LM6000PC SPRINT Simple cycle combustion turbine	Pipeline quality natural gas	405.3	MMBTU/hr	Nitrogen Oxides (NOx)	water injection	25	PPMDV	24-HR ROLLING AVE; CORRECTED TO 15% O	BACT-PSD		269.3	TONS	12 MO CALENDAR BASIS, FOR ALL 4 UNITS	0		
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	PSD-LA-792	221210	03/21/2016 ACT	A new facility to liquefy 8.0 million metric tons per year of natural gas	Gas Turbines (8 units)	natural gas	333	mm btu/hr	Nitrogen Oxides (NOx)	Dry Low NOX burners and good combustion practices	25	PPMVD	@15 %O2	BACT-PSD	NSPS	0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

NO_x

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	25	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	Natural gas	667	MMBTU/H	Nitrogen Oxides (NOx)	Dry low NOx burners (DLNB) and good combustion practices.	25	PPM	AT 15%O2;4-HR ROLL AVG; SEE NOTES BELOW	BACT-PSD	NSPS , SIP	60	LB/H	24-HR ROLL AVG; SEE NOTES BELOW	0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Nitrogen Oxides (NOx)	DLNB and good combustion practices.	25	PPM	4-HR ROLL AVG EXCEPT LESS THAN 75% PEAK	BACT-PSD	NSPS , SIP	60	LB/H	24-HR ROLL AVG EXCEPT SS	0		
TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Nitrogen Oxides (NOx)	Dry low emission combustors	25	PPMVD	@ 15% O2, 4 HOUR ROLLING AVG	BACT-PSD		0			0		
TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Nitrogen Oxides (NOx)	dry low emission combustors	25	PPMVD	@15% O2, 4 HOUR ROLLING AVERAGE	BACT-PSD		0			0		
TX-0816	CORPUS CHRISTI LIQUEFACTION	CORPUS CHRISTI LIQUEFACTION STAGE III, LLC	TX	139479, PSDTX1496, GHGPSDTX157	221210	02/14/2017 ACT	Trains 4 and 5 will consist of 12 natural gas compressor turbines, 2 thermal oxidizers, 2 sets of flares each comprised of one wet gas flare and one dry gas flare, 2 amine surge tanks (maintenance, startup, and shutdown [MSS] only), 3 diesel generators, 3 fire-water pump diesel engines, 6 fixed roof diesel storage tanks, and piping components.	Refrigeration compressor turbines	NATURAL GAS	40000	HP	Nitrogen Oxides (NOx)	Dry low emission burners	25	PPMDV	@ 15% O2	BACT-PSD	NSPS	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR), exclusive combustion of fuel gas, and good combustion practices.	25	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0343	SABINE PASS LNG TERMINAL	SABINE PASS LNG LP AND SABINE PASS LIQUEFACTION LL	LA	PSD-LA-703(M7)	488999	09/06/2019 ACT	a terminal to import lng and liquefy/export natural gas Modification to add startup, shutdown, maintenance scenarios	gas turbines during startups, shutdowns, and maintenance	natural gas	0		Nitrogen Oxides (NOx)	good combustion practices	96	PPMV	@ 15% O2	BACT-PSD	NSPS	0			0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines MSS	NATURAL GAS	0		Nitrogen Oxides (NOx)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR		BACT-PSD		0			0		
CA-1223	PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	CA	SD 11-01	221112	11/19/2012 ACT	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	COMBUSTION TURBINES (STARTUP & SHUTDOWN PERIODS)	NATURAL GAS	300	MW	Nitrogen Oxides (NOx)	water injection and SCR system	22.5	LB/H	STARTUP EVENTS	BACT-PSD		6	LB/H	SHUTDOWN EVENTS	0		
CO-0076	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	09PB0591	221112	12/11/2014 ACT	Electric generation	Turbines - two simple cycle gas	natural gas	799.7	MMBTU/H each	Nitrogen Oxides (NOx)	SCR and dry low NOx burners	23	LB/H	1-HR AVE / STARTUP AND SHUTDOWN	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
CO-0076	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	09PB0591	221112	12/11/2014 ACT	Electric generation	Turbines - two simple cycle gas	natural gas	799.7	MMBTU/H each	Nitrogen Oxides (NOx)	SCR and dry low NOx burners	23	LB/H	1-HR AVE / STARTUP AND SHUTDOWN	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	EUGU 3030 - Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hR	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	86.38	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	EUGU 3030 - Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	86.38	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	EUGU CO - Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	Natural Gas	2201	MM BTU/hr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	240	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	42	TONS/YR	ANNUAL AVERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	EUGU CO - Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	natural gas	2201	MM BTU/hr	Nitrogen Oxides (NOx)	Pipeline quality natural gas & dry-low-NOX burners	240	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	42	TONS/YR	ANNUAL AVERAGE	0		
IN-0261	VERMILLION GENERATING STATION	DUKE ENERGY INDIANA, LLC VERMILLION GENERATING STA	IN	165-36956-00022	221112	02/28/2017 ACT	ELECTRIC UTILITY SERVICES	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	80	MW	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	250	LB/H	EACH TURBINE	BACT-PSD		25	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	ENGINEERED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISSION LIMIT = 6.2 TONS/YR	2 COMBUSTION TURBINES	NATURAL GAS	130	MW	Carbon Monoxide	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS, USE OF AN OXIDATION CATALYST AND EFFICIENT COMBUSTION	1.5	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXLUDING SU/SD	BACT-PSD		562.4	LB/EVENT	FOR ALL STARTUPS	0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 212 acres, including 192 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Four Combined Cycle Gas-Fired Turbines	Natural Gas	384	MMBtu/hr	Carbon Monoxide	Oxidation Catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS	BACT-PSD		0			0		
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	TX	N284, PSDTX1090M1, GHGPSDTX199	221112	08/27/2021 ACT	a new natural gas simple cycle turbine along with ancillary equipment.	Simple Cycle Turbine	natural gas	230	MW	Carbon Monoxide	Oxidation catalyst	3	PPMVD		BACT-PSD	NSPS , MACT	0			0		
VA-0326	DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	VA	51018	221112	10/04/2016 ACT	The facility is currently composed of four Kawasaki Gasturbine Division Siemens (model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The	Two (2) GE 7FA simple cycle combustion turbines	Natural Gas	1961	MMBTU/HR	Carbon Monoxide	Pipeline Quality Natural Gas	13.99	LB	H/12 MO ROLLING TOTAL	BACT-PSD		0.0071	LB	MMBTU/12 MO ROLLING TOTAL	0		
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	SIMPLE CYCLE TURBINE	NATURAL GAS	14552539	MMBTU/YR	Carbon Monoxide	Oxidation catalyst	3.5	PPMVD	3-HR ROLLING	BACT-PSD	NSPS , MACT	0			0		
FL-0346	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-011-AC	221112	04/22/2014 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2000	MMBtu/hr (approx)	Carbon Monoxide	Good combustion practices	4	PPMVD @ 15% O2		BACT-PSD		21	LB/H		0		
FL-0354	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-013-AC	221112	08/25/2015 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2100	MMBtu/hr (approx)	Carbon Monoxide	Good combustion minimizes CO formation	4	PPMVD@15%O2	NAT GAS, THREE 1-HR RUNS	BACT-PSD	SIP	9	PPMVD@15%O2	ULSD, THREE 1-HR RUNS	0		
TX-0694	INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	TX	111724 PSDTX1374	221112	02/02/2015 ACT	Indeck Wharton, L.L.C. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will either be the General Electric 7FA (~214 MW each) or the Siemens SGT6-5000F (~227 MW each), operating as peaking units in simple cycle mode.	(3) combustion turbines	natural gas	220	MW	Carbon Monoxide	DLN combustors	4	PPMVD	@15% O2, 3-HR ROLLING AVG - SIEMENS	BACT-PSD		9	PPMVD	@15% O2, 3-HR ROLLING AVG - GE 7FA	0		
NJ-0086	BAYONNNE ENERGY CENTER	BAYONNNE ENERGY CENTER LLC	NJ	12863-BOP150001	221112	08/26/2016 ACT	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	Simple Cycle Stationary Turbines firing Natural gas	Natural Gas	2143980	MMBTU/YR	Carbon Monoxide	Add-on control is CO Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	5	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK AV	OTHER CASE-BY-CASE	OPERATING PERMIT	7.21	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 212 acres, including 192 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Six Simle Cycle Gas-Fired Turbines	Natural Gas	1113	MMBtu/hr	Carbon Monoxide	Oxidation Catalyst and good combustion practices	5	PPMV @ 15% O2	3-HOURS	BACT-PSD		0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CTG01 NO - Simple Cycle Combustion Turbine 1 (Normal Operations) (EQT0017)	Natural Gas	2201	MM BTU/hr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	6	PPMVD AT 15% OXYGEN	ANNUAL AVERAGE	BACT-PSD	OPERATING PERMIT	34.42	LB/HR	HOURLY MAXIMUM	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CTG02 NO - Simple Cycle Combustion Turbine 2 (Normal Operations) (EQT0018)	Natural Gas	2201	MM BTU/hr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	6	PPMVD AT 15% O2	ANNUAL AVERAGE	BACT-PSD	OPERATING PERMIT	34.42	LB/HR	HOURLY MAXIMUM	0		
ND-0029	PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	ND	PTC 13037	221112	05/14/2013 ACT	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	Natural gas-fired turbines	Natural gas	451	MMBTU/H	Carbon Monoxide	Catalytic oxidation system	6	PPMVD	8 HR. ROLLING AVERAGE/EXCEPT STARTUP	BACT-PSD		57.2	LB/H	DURING STARTUP	0		
ND-0030	LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	ND	PTC 13049	221112	09/16/2013 ACT	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.	Natural Gas Fired Simple Cycle Turbines	Natural gas	412	MMBTU/H	Carbon Monoxide	Oxidation Catalyst	6	PPMVD	8-HOUR ROLLING AVERAGE EXCEPT STARTUP	BACT-PSD		31.5	LB	30 MINUTE TOTAL FOR STARTUP	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS-100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Carbon Monoxide	Oxidation catalyst; Limit the time in startup or shutdown.	6	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG	BACT-PSD		6	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON ULSD	0		
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	Carbon Monoxide	Oxidation Catalyst	6	PPMV AT 15% O2	1-HOUR	BACT-PSD		5.6	LB/H	30-DAY ROLLING AVERAGE	32.9	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP04)	Natural Gas	40	MW	Carbon Monoxide	Oxidation Catalyst	6	PPMV AT 15% O2	1-HOUR	BACT-PSD		5.6	LB/H	30-DAY ROLLING AVERAGE	32.9	T/YR	
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	Carbon Monoxide	Oxidation Catalyst	6	PPMV AT 15% O2	1-HOUR AVERAGE	BACT-PSD		5.6	LB/H	30-DAY ROLLING AVERAGE	32.9	T/YR	
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS-100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Carbon Monoxide	Oxidation catalyst; Limit the time in startup or shutdown.	6	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON NG	BACT-PSD		6	PPMDV AT 15% O2	3-HR ROLLING AVERAGE ON ULSD	0		
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	AL	701-0010	221112	09/21/2021 ACT	Electric Generating Facility	Three 229 MW Simple Cycle Combustion Turbines	Natural Gas	229	MW	Carbon Monoxide		9	PPMVD	3 HOUR AVG / @15% O2	BACT-PSD		500	LBS/EVENT	STARTUP AND SHUTDOWN	0		
TX-0686	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	109148, PSDTX1358	221112	04/22/2014 ACT	GSEC is proposing to build three additional new CTGs at the existing Antelope Elk Energy Center. The new facility will provide primarily peaking and intermediate power needs. The new units will be GE 7FS-Series gas turbines in simple cycle application, rated at 202 MW. Each turbine will operate a maximum of 4,572 hours per year.	Combustion Turbine-Generator(CTG)	Natural Gas	202	MW	Carbon Monoxide	Good combustion practices; limited hours	9	PPMVD	15% O2, 3HR AVG.	BACT-PSD		0			0		
TX-0688	SR BERTRON ELECTRIC GENERATION STATION	NRG TEXAS POWER	TX	102731, PSDTX1294	221112	12/19/2014 ACT	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy	Simple cycle natural gas turbines	Natural Gas	225	MW	Carbon Monoxide	Good Combustion Practices	9	PPM	1HR ROLLING AVG.	BACT-PSD		0			0		
TX-0690	CEDAR BAYOU ELECTRIC GERNERATION STATION	NRG TEXAS POWER	TX	105810, PSDTX130B	221112	09/12/2012 ACT	NRG is proposing to construct an additional electric power generation station at the existing site. The project will include two power blocks that can be operated in simple cycle or combined cycle modes. This entry is for the simple cycle operation. Each power block will contain a CTG with duct burners and HRSG. Three options were proposed: Siemens Model F5, GE7Fa, and Mitsubishi Heavy	Simple Cycle Combustion Turbines	Natural Gas	225	MW	Carbon Monoxide	Good Combustion Practices	9	PPM	1HR ROLLING AVG.	BACT-PSD		0			0		
TX-0693	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE INC	TX	109148 PSDTX1358	221112	04/22/2014 ACT	Golden Spread Electric Cooperative (GSEC) currently owns and operates the Antelope Station (now renamed Antelope Elk Energy Center), a 168 MW generating facility made up of 18 quick start WÃ¤rtsilÃ¤ engines. GSEC is proposing to build a new combustion turbine-generator (CTG) facility at Antelope Station, while the 18 WÃ¤rtsilÃ¤ engines will remain and continue to be	combustion turbine	natural gas	202	MW	Carbon Monoxide	DLN combustors, good combustion practices	9	PPMVD	@15% O2. 3-HR ROLLING AVERAGE	BACT-PSD		0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0695	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	110423 PSDTX1366	221112	08/01/2014 ACT	The proposed project is to construct and operate two natural gas-fired simple-cycle combustion turbine generators (CTGs) at the Ector County Energy Center (ECEC), located approximately 20 miles northwest of Odessa, Texas, in Ector County.	(2) combustion turbines	natural gas	180	MW	Carbon Monoxide	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVG	BACT-PSD		0			0		
TX-0696	ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	TX	114698 PSDTX1378	221112	09/22/2014 ACT	The proposed project is to construct and operate one of 3 comprised of three new simple cycle combustion turbine generators (CTG), fueled by pipeline quality natural gas. The new CTGs will be peaking units, designed to operate during periods of high electric demand. The three CTGs will produce between 507 and 694 MW of electricity combined, depending on ambient temperature and the	(2) simple cycle turbines	natural gas	600	MW	Carbon Monoxide	DLN combustors	9	PPMVD	@15% O2, 3-HR ROLLING AVERAGE	BACT-PSD		0			0		
TX-0701	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	110423, PSDTX1366	221112	05/13/2013 ACT	The proposed project is for two natural gas fired simple cycle CTGs. The proposed models include GE7Fa.03 and GE7Fa.05. They have an output of 165-193 MW. The new CTGs will operate as peaking units and will be limited to 2500 hours per year of operation each.	Simple Cycle Combustion Turbines	natural gas	180	MW	Carbon Monoxide	Good combustion practices	9	PPMVD	15%O2, 3HR AVERAGE	BACT-PSD		0			0		
TX-0733	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	109148, PSDTX1358M1	221112	05/12/2015 ACT	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.	Simple Cycle Turbine & Generator	natural gas	202	MW	Carbon Monoxide	Good combustion practices; limited operating hours	9	PPMVD @ 15% O2	3-HR AVERAGE	BACT-PSD		0			0		
TX-0734	CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	TX	120849 AND PSDTX1414	221112	05/08/2015 ACT	Navasota South Peakers Operating Company II LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Carbon Monoxide	DLN burners and good combustion practices	9	PPMVD @ 15% O2	ALL LOADS	BACT-PSD	NSPS	0			0		
TX-0764	NACOGDOCHES POWER ELECTRIC GENERATING PLANT	NACOGDOCHES POWER, LLC	TX	77679, PSDTX1061M1 & O-3455	221112	10/14/2015 ACT	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).	Natural Gas Simple Cycle Turbine (>25 MW)	natural gas	232	MW	Carbon Monoxide	dry low NOx burners, good combustion practices, limited operation	9	PPMVD @ 15% O2		BACT-PSD		0			0		
TX-0768	SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	TX	PSDTX1442, 125963	221112	10/09/2015 ACT	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.	Simple cycle turbines greater than 25 megawatts (MW)	natural gas	230	MW	Carbon Monoxide	dry low NOx burners and lmiited operation, clean fuel	9	PPMVD @ 15% O2		BACT-PSD	NSPS	0			0		
TX-0769	VAN ALSTYNE ENERGY CENTER (VAEC)	NAVASOTA NORTH COUNTRY PEAKERS OPERATING COMPANY I	TX	121051 AND PSDTX1418	221112	10/27/2015 ACT	Navasota North Country Peakers Operating Company I LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 MW each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Carbon Monoxide	DLN burners and good combustion practices	9	PPMVD @ 15% O2		BACT-PSD	NSPS	0			0		
TX-0777	UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY I, LLC.	TX	120973 AND PSDTX1420	221112	12/09/2015 ACT	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle	Simple Cycle Turbine	natural gas	183	MW	Carbon Monoxide	dry low NOx burners and good combustion practices	9	PPMVD @ 15% O2	ALL LOADS	BACT-PSD	NSPS	0			0		
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	TX	122401, PSDTX1428, GHGPSDTX111	221112	03/24/2016 ACT	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.	Large Combustion Turbines > 25 MW	natural gas	232	MW	Carbon Monoxide	good combustion practices	9	PPM		BACT-PSD	NSPS	0			0		
TX-0794	HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	TX	130051,PSDTX1450, GHGPSDTX131	221112	04/07/2016 ACT	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(S)ee. Electric output is between 684 and 928 megawatts (MW).	Simple cycle turbine	natural gas	171	MW	Carbon Monoxide	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	9	PPMVD @ 15% O2	3-HR AVERAGE	BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Carbon Monoxide	Good combustion practices; limited operating hours	9	PPMVD	3% O2 3-H AVG	BACT-PSD		0			0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines	natural gas	920	MW	Carbon Monoxide	Dry low NOx burners	9	PPMVD		BACT-PSD	NSPS	0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	TURBINE	NATURAL GAS	0		Carbon Monoxide	Oxidization catalyst, good combustion practices and the use of gaseous fuel	9	PPMVD	15% O2	BACT-PSD		0			0		
WV-0026	WAVERLY FACILITY	PLEASANTS ENERGY, LLC	WV	R14-0034	221112	01/23/2017 ACT	300 MW, natural gas fired, simple cycle peaking power facility	GE Model 7FA Turbine	Natural Gas	1571	mmbtu/hr	Carbon Monoxide	Good Combustion Practices	9	PPM	NATURAL GAS	BACT-PSD		20	PPM	FUEL OIL	9	PPM	NATURAL GAS
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	PORT ARTHUR LNG, LLC	TX	131769, PSDTX1456, GHGPSDTX134	486210	02/17/2016 ACT	Liquefied natural gas (LNG) export terminal	Simple Cycle Electrical Generation Gas Turbines 15.210	natural gas	34	MW	Carbon Monoxide	OXIDATION CATALYST	9	PPM	ROLLING 3-HR AVERAGE	BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Carbon Monoxide	Good combustion practices; limited operating hours	9	PPMVD	3% O2 3-H AVG	BACT-PSD		0			0		
WV-0028	WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	WV	R14-0034A	221112	03/13/2018 ACT	300 MW Sinple-Cycle Peaking Plant	GE 7FA.004 Turbine	Natural Gas	167.8	MW	Carbon Monoxide	Combustion Controls	33.9	LB/HR		BACT-PSD		235.54	TONS/YEAR		9	PPM	
*LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	LA	PSD-LA-838	486210	09/03/2020 ACT	A greenfield facility to liquefy and export natural gas.	Turbines (EQT0020 - EQT0031)	Natural gas	0		Carbon Monoxide	catalytic oxidation and carbon monoxide turndown	10	PPMVD @15%O2	3-HOUR AVERAGE, @ LOAD =>50%	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Carbon Monoxide	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.03	LB/MMBTU	3-HR AVERAGE AT > 50% PEAK LOAD	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Carbon Monoxide	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.03	LB/MMBTU	3-HR AVERAGE AT > 50% PEAK LOAD	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Carbon Monoxide	Good Combustion Practices and burning clean fuels (NG)	15	PPMV @ 15% O2	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Carbon Monoxide	Good Combustion Practices and burning clean fuels (NG)	15	PPMV @ 15% O2	3-HOUR AVERAGE	BACT-PSD		0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	Gas turbines (9 units)	natural gas	1069	mm btu/hr	Carbon Monoxide	good combustion practices and fueled by natural gas	15	PPMVD	@15%O2	BACT-PSD		0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Carbon Monoxide	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	25	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0349	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	LA	PSD-LA-824	221210	07/10/2018 ACT	Propose a new facility to liquefy natural gas for export	Compressor Turbines (20)	natural gas	540	mm btu/hr	Carbon Monoxide	Good Combustion Practices	25	PPMVD	@ 15% O2	BACT-PSD	NSPS	0			0		
ND-0028	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	PTC13016	221112	02/22/2013 ACT	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.	Combustion Turbine	Natural gas	986	MMBTU/H	Carbon Monoxide	Good Combustion	25	PPMVD @ 15% OXYGEN	4 H.R.A./WHEN > 50 MWE	BACT-PSD		27	TONS/30 DAY	30 DAY ROLLING TOTAL / WHEN < 50 MWE	0		
TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	108182 PSDTX1346	221112	05/20/2014 ACT	NRG proposes to construct six natural gas-fired simple cycle combustion turbine generators (CTG) for peaking, designed to operate during periods of high electric demand. The six CTGs selected by NRG are General Electric Frame 7E turbines have an ISO rating of 65 MW and a nominal maximum generating capacity of 80 MW. Each of the turbines will not exceed 20 percent annual capacity (equivalent	(6) simple cycle turbines	natural gas	65	MW	Carbon Monoxide	DLN combustors	25	PPMVD	@15% O2, 3-HR ROLLING AVERAGE	BACT-PSD		0			0		
TX-0851	RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	TX	140792, PSDTX1498, GHGPSDTX158	486210	12/17/2018 ACT	Natural gas processing and liquefied natural gas (LNG) export terminal	Refrigeration Compression Turbines	NATL GAS	967	MMBTU/HR	Carbon Monoxide	Dry Low NOx burners. Good combustion practices	25	PPMVD	15% O2	BACT-PSD	NSPS , NESHAP	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Carbon Monoxide	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	25	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Carbon Monoxide	dry low emission combustors	29	PPMVD	@15% O2, 4 HOUR ROLLING AVERAGE	BACT-PSD		0			0		
TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Carbon Monoxide	dry low emission combustors	29	PPMVD	@15% O2, 4 HOUR ROLLING AVERAGE	BACT-PSD		0			0		
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	PSD-LA-792	221210	03/21/2016 ACT	A new facility to liquefy 8.0 million metric tons per year of natural gas	Gas Turbines (8 units)	natural gas	333	mm btu/hr	Carbon Monoxide	good combustion practices and fueled by natural gas	0.062	LB/MM BTU	THREE ONE-HOUR TEST AVERAGE	BACT-PSD		0			0		
TX-0816	CORPUS CHRISTI LIQUEFACTION	CORPUS CHRISTI LIQUEFACTION STAGE III, LLC	TX	139479, PSDTX1496, GHGPSDTX157	221210	02/14/2017 ACT	Three 4 MW gas turbines as natural gas compressor turbines, 4 thermal oxidizers, 2 sets of flares each comprised of one wet gas flare and one dry gas flare, 2 amine surge tanks (maintenance, startup, and shutdown [MSS] only), 3 diesel generators, 3 fire-water pump diesel engines, 6 fixed roof diesel storage tanks, and piping components.	Refrigeration compressor turbines	NATURAL GAS	40000	HP	Carbon Monoxide	Dry low emission burners	29	PPMDV	@ 15% O2	BACT-PSD		0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Carbon Monoxide	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	36	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Carbon Monoxide	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	36	PPMV	30 DAY ROLLING AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
NY-0106	GREENIDGE STATION	GREENIDGE GENERATION LLC	NY	8-5736-00004/00017	221112	09/07/2016 ACT	Greenidge Generation LLC has submitted a revised application for a Title V Air Permit in accordance with the requirements of Title 6 of the New York compilation of Codes, Rules, and Regulations, Part 201-6 (6 NYCRR Part 201-6). The application is for conversion of the Greenidge Electricity Generating Station, located in the Town of Torrey, Yates County to operate primarily on natural gas	Turbine - natural gas	natural gas	107	MW	Carbon Monoxide		0.095	LB/MMBTU	12 MO	BACT-PSD		0.037	LB/MMBTU	24 H	0		
NY-0106	GREENIDGE STATION	GREENIDGE GENERATION LLC	NY	8-5736-00004/00017	221112	09/07/2016 ACT	Greenidge Generation LLC has submitted a revised application for a Title V Air Permit in accordance with the requirements of Title 6 of the New York compilation of Codes, Rules, and Regulations, Part 201-6 (6 NYCRR Part 201-6). The application is for conversion of the Greenidge Electricity Generating Station, located in the Town of Torrey, Yates County to operate primarily on natural gas	Turbine - natural gas and wood	natural gas and up to 19% wood	107	MW	Carbon Monoxide		0.095	LB/MMBTU	12 MO	BACT-PSD		0.075	LB/MMBTU	24 H	0		
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	MI	191-12	221112	07/25/2013 ACT	Four (4) natural gas fired combined cycle combustion turbine generators (CTG) and heat recovery steam generators (HRSG) with duct burner firing capability; ancillary facility equipment.	Four (4) natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Carbon Monoxide	Efficient combustion	0.11	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG. TIME	BACT-PSD	N/A	0			0		
IN-0264	MONTPELIER GENERATING STATION	AES OHIO GENERATION, LLC	IN	179-37209-00026	221112	01/06/2017 ACT	COMBUSTION TURBINES	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	NATURAL GAS	270.9	MMBTU/H	Carbon Monoxide	NATURAL GAS AS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	0.2	LB/MMBTU	NATURAL GAS	BACT-PSD		0.3	LB/MMBTU	FUEL OIL	0		
TX-0833	JACKSON COUNTY GENERATORS	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines MSS	NATURAL GAS	0		Carbon Monoxide	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.01	TON/YR		BACT-PSD		0			0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Carbon Monoxide	Dry low NOx burners and good combustion practices	9	LB/H	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN	BACT-PSD	SIP	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	Natural gas	667	MMBTU/H	Carbon Monoxide	Dry low NOx burners and good combustion practices.	9	LB/H	HOURLY EXCEPT DURING STARTUP/SHUTDOWN	BACT-PSD	SIP	0			0		
MI-0447	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Carbon Monoxide	Dry low NOx burners and good combustion practices	9	LB/H	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN	BACT-PSD	SIP	0			0		
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE 7FA Simple Cycle Combustion Turbine	Pipeline quality natural gas	1780	MMBTU/HR	Carbon Monoxide	utilize efficient combustion/design technology	39	LB/HR	AT FULL LOAD	BACT-PSD		0			0		
CO-0076	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	09PB0591	221112	12/11/2014 ACT	Electric generation	Turbines - two simple cycle gas	natural gas	799.7	MMBTU/H each	Carbon Monoxide	Catalytic Oxidation.	55	LB/H	1-HR AVE / STARTUP AND SHUTDOWN	BACT-PSD	OPERATING PERMIT , NSPS	0			0		
CO-0076	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	09PB0591	221112	12/11/2014 ACT	Electric generation	Turbines - two simple cycle gas	natural gas	799.7	MMBTU/H each	Carbon Monoxide	Catalytic Oxidation.	55	LB/H	1-HR AVE / STARTUP AND SHUTDOWN	BACT-PSD	OPERATING PERMIT , NSPS	0			0		
*KS-0036	WESTAR ENERGY - EMPORIA ENERGY CENTER	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE LM6000PC SPRINT Simple cycle combustion turbine	Pipeline quality natural gas	405.3	MMBTU/hr	Carbon Monoxide	utilize efficient combustion/design technology	63.8	LB/HR	FULL LOAD, AMBIENT TEMP < OR = TO 54 F	BACT-PSD		36	LB/HR	FULL LOAD, AMBIENT TEMP > 54 F	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IN-0261	VERMILLION GENERATING STATION	DUKE ENERGY INDIANA, LLC VERMILLION GENERATING STA	IN	165-36956-00022	221112	02/28/2017 ACT	ELECTRIC UTILITY SERVICES	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	80	MW	Carbon Monoxide	GOOD COMBUSTION PRACTICES	525	LB/H	EACH TURBINE	BACT-PSD		52.5	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	LMS6 100 Simple-Cycle Combustion Turbine 1 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hR	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	800.08	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	LMS6 100 Simple-Cycle Combustion Turbine 2 (Startup/Shutdown/	Natural Gas	2201	MM BTU/hr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	800.08	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	LMS6 100 Simple-Cycle Combustion Turbine 1 (Commissioning) [SCN0005]	Natural Gas	2201	MM BTU/hr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	2000	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	350	TONS/YR	ANNUAL AVEERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	LMS6 100 Simple-Cycle Combustion Turbine 2 (Commissioning) [SCN0006]	natural gas	2201	MM BTU/hr	Carbon Monoxide	Good combustion practices & use of pipeline quality natural gas	2000	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	350	TONS/YR	ANNUAL AVERAGE	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MD-0044	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	2 COMBUSTION TURBINES	NATURAL GAS	130	MW	Volatile Organic Compounds (VOC)	THE USE OF PROCESS FUEL GAS AND PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	0.7	PPMVD @ 15% O2	3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	LAER		101.1	LB/EVENT	FOR ALL STARTUPS	0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Volatile Organic Compounds (VOC)	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.4	PPMV	3 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT , NSPS	0			0		
TX-0696	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	TX	114698 PSDTX1378	221112	09/22/2014 ACT	THE PROPOSED PROJECT IS TO CONSTRUCT AND OPERATE SIX (6) GAS-FIRED COMBUSTION TURBINE new simple cycle combustion turbine generators (CTG), fueled by pipeline quality natural gas. The new CTGs will be peaking units, designed to operate during periods of high electric demand. The three CTGs will produce between 507 and 694 MW of electricity combined, depending on ambient temperature	(2) simple cycle turbines	natural gas	600	MW	Volatile Organic Compounds (VOC)	good combustion	1.4	PPMVD	@15% O2 GE OPTION	BACT-PSD		1	PPMVD	@15% O2 SIEMENS OPTION	0		
TX-0768	SHAWNEE ENERGY CENTER, LLC	TX	PSDTX1442, 125963	221112	10/09/2015 ACT	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.	Simple cycle turbines greater than 25 megawatts (MW)	natural gas	230	MW	Volatile Organic Compounds (VOC)	Pipeline quality natural gas; limited hours; good combustion practices.	1.4	PPMV		BACT-PSD	NSPS	0			0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Volatile Organic Compounds (VOC)	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.4	PPMV	3 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT , NSPS	0			0		
LA-0349	DRIFTWOOD LNG LLC	LA	PSD-LA-824	221210	07/10/2018 ACT	Propose a new facility to liquefy natural gas for export	Compressor Turbines (20)	natural gas	540	mm btu/hr	Volatile Organic Compounds (VOC)	Good Combustion Practices and Use of low sulfur facility fuel gas	0.002	LB/MM BTU	HHV	BACT-PSD		0			0		
*TX-0915	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	SIMPLE CYCLE TURBINE	NATURAL GAS	14552539	MMBTU/YR	Volatile Organic Compounds (VOC)	Oxidation catalyst	1.5	PPMVD	3-HR ROLLING	BACT-PSD	NSPS , MACT	0			0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Volatile Organic Compounds (VOC)	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.5	PPMV	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Volatile Organic Compounds (VOC)	Proper Equipment Design, Proper Operation, and Good Combustion Practices.	1.5	PPMV	3 HOUR AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0316	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	Gas turbines (9 units)	natural gas	1069	mm btu/hr	Volatile Organic Compounds (VOC)	good combustion practices and fueled by natural gas	1.6	PPMVD	@15%O2	BACT-PSD		0			0		
*AK-0085	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Volatile Organic Compounds (VOC)	Good Combustion Practices and burning clean fuels (NG)	0.0022	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Volatile Organic Compounds (VOC)	Good Combustion Practices and burning clean fuels (NG)	0.0022	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*TX-0933	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	TURBINE	NATURAL GAS	0		Volatile Organic Compounds (VOC)	Oxidization catalyst, good combustion practices and the use of gaseous fuel	1.7	PPMVD		BACT-PSD		0			0		
*TX-0908	EL PASO ELECTRIC COMPANY	TX	N284, PSDTX1090M1, GHGPSDTX199	221112	08/27/2021 ACT	a new natural gas simple cycle turbine along with ancillary equipment.	Simple Cycle Turbine	natural gas	230	MW	Volatile Organic Compounds (VOC)	Use of Natural gas, good combustion practices, and oxidation catalyst	2	PPMVD		BACT-PSD	NSPS , MACT	0			0		
CA-1238		CA	00013-370	221112	10/13/2016 ACT	Utility	Gas turbine	Natural gas	262	MW	Volatile Organic Compounds (VOC)		2	PPMVD AS METHANE	1 HOUR@15%O2	OTHER CASE-BY-CASE		0			0		
NJ-0086	BAYONNNE ENERGY CENTER LLC	NJ	12863-BOP150001	221112	08/26/2016 ACT	Facility consists of 8 existing Roll Royce Trent 60 WLE (64 MW) each. The facility is adding two more new Roll Royce Trent 60 WLE (66 MW) each	Simple Cycle Stationary Turbines firing Natural gas	Natural Gas	2143980	MMBTU/YR	Volatile Organic Compounds (VOC)	Add-on VOC control is Oxidation Catalyst, and use of natural gas as fuel for pollution prevention	2	PPMVD@15%O2	3 H ROLLING AV BASED ON ONE H BLOCK AV	OTHER CASE-BY-CASE	OPERATING PERMIT	1.65	LB/H	AV OF THREE ONE H STACK TESTS EVERY 5 YR	0		
TX-0733	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	109148, PSDTX1358M1	221112	05/12/2015 ACT	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting authorization for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7F5-Series natural gas-fired combustion turbine generators (CTGs). Each turbine has a maximum electric output of 202 MW.	Simple Cycle Turbine & Generator	natural gas	202	MW	Volatile Organic Compounds (VOC)	Good combustion practices	2	PPMVD @ 15% O2		BACT-PSD		0			0		
TX-0764	NACOGDOCHES POWER, LLC	TX	77679, PSDTX1061M1 & O-3455	221112	10/14/2015 ACT	Nacogdoches Power, LLC is requesting authorization for one natural gas fired, simple cycle combustion turbine generator (CTG). The CTG will be a Siemens F5 and have a nominal electric output of 232 megawatts (MW).	Natural Gas Simple Cycle Turbine (>25 MW)	natural gas	232	MW	Volatile Organic Compounds (VOC)	Pipeline quality natural gas; limited hours; good combustion practices.	2	PPMVD @ 15% O2		BACT-PSD		0			0		
TX-0788	APEX TEXAS POWER LLC	TX	122401, PSDTX1428, GHGPSDTX111	221112	03/24/2016 ACT	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.	Large Combustion Turbines > 25 MW	natural gas	232	MW	Volatile Organic Compounds (VOC)	good combustion practices	2	PPM		BACT-PSD	NSPS	0			0		
TX-0819	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Volatile Organic Compounds (VOC)	Pipeline quality natural gas; limited hours; good combustion practices	2	PPMVD	145% O2	BACT-PSD		0			0		
TX-0833	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines	natural gas	920	MW	Volatile Organic Compounds (VOC)	Good combustion practices	2	PPMVD		BACT-PSD	NSPS	0			0		
TX-0851	RIO GRANDE LNG LLC	TX	140792, PSDTX1498, GHGPSDTX158	486210	12/17/2018 ACT	Natural gas processing and liquefied natural gas (LNG) export terminal	Refrigeration Compression Turbines	NATL GAS	967	MMBTU/HR	Volatile Organic Compounds (VOC)	Good combustion practices	2	PPMVD	15% O2	BACT-PSD	NSPS , NESHAP	0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0790	PORT ARTHUR LNG, LLC	TX	131769, PSDTX1456, GHGPSDTX134	486210	02/17/2016 ACT	Liquefied natural gas (LNG) export terminal	Simple Cycle Electrical Generation Gas Turbines 15.210	natural gas	34	MW	Volatile Organic Compounds (VOC)	OXIDATION CATALYST	2	PPM	3-HR AVERAGE	BACT-PSD		0			0		
TX-0819	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	construction of phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only	Simple Cycle Turbine	natural gas	227.5	MW	Volatile Organic Compounds (VOC)	Pipeline quality natural gas; limited hours; good combustion practices	2	PPMVD	145% O2	BACT-PSD		0			0		
*AK-0088	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 321 acres, including 301 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Six Simle Cycle Gas-Fired Turbines	Natural Gas	1113	MMBtu/hr	Volatile Organic Compounds (VOC)	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS	BACT-PSD		0			0		
*AK-0088	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 321 acres, including 301 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist	Four Combined Cycle Gas-Fired Turbines	Natural Gas	384	MMBtu/hr	Volatile Organic Compounds (VOC)	Oxidation catalyst and good combustion practices	2	PPMV @ 15% O2	3-HOURS	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	2.5	PPMVD AT 15% OXYGEN	1-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	2.5	PPMVD AT 15% OXYGEN	1-HR AVERAGE	BACT-PSD		0			0		
WY-0070	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	Volatile Organic Compounds (VOC)	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	BACT-PSD		3	LB/H	3-HOUR AVERAGE	14	T/YR	
WY-0070	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Trubine (EP04)	Natural Gas	40	MW	Volatile Organic Compounds (VOC)	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	BACT-PSD		3	LB/H	3-HOUR AVERAGE	14	T/YR	
WY-0070	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	Volatile Organic Compounds (VOC)	Oxidation Catalyst	3	PPMV AT 15% O2	3-HOUR AVERAGE	BACT-PSD		3	LB/H	3-HOUR AVERAGE	14	T/YR	
MI-0410	CONSUMERS ENERGY COMPANY	MI	191-12	221112	07/25/2013 ACT	Four (4) natural gas fired combined cycle combustion turbine generators (CTG) and heat recovery steam generators (HRSG) with duct burner firing capability; ancillary facility equipment.	EUCTGSC1- 4 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Volatile Organic Compounds (VOC)	Efficient combustion; natural gas fuel.	0.017	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG. TIME.	BACT-PSD	N/A	0			0		
TX-0833	SOUTHERN POWER	TX	PSDTX1422	221112	01/26/2018 ACT	four natural gas-fired simple-cycle combustion turbines, five fuel gas heaters, and a firewater pump engine	Combustion Turbines MSS	NATURAL GAS	0		Volatile Organic Compounds (VOC)	Minimizing duration of startup/shutdown, using good air pollution control practices and safe operating practices.	0.06	TON/YR		BACT-PSD		0			0		
TX-0672	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Volatile Organic Compounds (VOC)	good combustion practices	0.6	LB/H	1 HOUR	BACT-PSD		0			0		
TX-0672	CORPUS CHRISTI LIQUEFACTION LLC	TX	PSDTX1306 105710	221210	09/12/2014 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual	Refrigeration compressor turbines	natural gas	40000	hp	Volatile Organic Compounds (VOC)	good combustion practices	0.6	LB/H	1 HOUR	BACT-PSD		0			0		
TX-0816	CORPUS CHRISTI LIQUEFACTION STAGE III, LLC	TX	139479, PSDTX1496, GHGPSDTX157	221210	02/14/2017 ACT	Trains 4 and 5 will consist of 12 natural gas compressor turbines, 2 thermal oxidizers, 2 sets of flares each comprised of one wet gas flare and one dry gas flare, 2 amine surge tanks (maintenance, startup, and shutdown [MSS] only), 3 diesel generators, 3 fire-water pump diesel engines, 6 fixed roof diesel storage tanks, and piping components.	Refrigeration compressor turbines	NATURAL GAS	40000	HP	Volatile Organic Compounds (VOC)	Good combustion practices	0.68	LB/H		BACT-PSD		0			0		
*KS-0036	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE 7FA Simple Cycle Combustion Turbine	Pipeline quality natural gas	1780	MMBTU/HR	Volatile Organic Compounds (VOC)	will utilize efficient combustion/design technology	3.2	LB/HR	AT FULL LOAD	BACT-PSD		0			0		
FL-0346	FLORIDA POWER & LIGHT	FL	0110037-011-AC	221112	04/22/2014 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2000	MMBtu/hr (approx)	Volatile Organic Compounds (VOC)	Good combustion practice	3.77	LB/H	THREE ONE-HR RUNS (NATURAL GAS)	BACT-PSD		8	LB/H	THREE ONE-HR RUNS (OIL)	0		
MI-0447	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Volatile Organic Compounds (VOC)	Good combustion practices	5	LB/H	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN	BACT-PSD		0			0		
MI-0441	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUCTGSC1-A nominally rated 667 MMBTU/hr natural gas-fired simple cycle CTG	Natural gas	667	MMBTU/H	Volatile Organic Compounds (VOC)	Good combustion practices.	5	LB/H	HOURLY EXCEPT DURING STARTUP/SHUTDOWN	BACT-PSD		0			0		
MI-0447	LANSING BOARD OF WATER AND LIGHT	MI	74-18A	221112	01/07/2021 ACT	Natural gas combined-cycle power plant	EUCTGSC1-natural gas fired simple cycle CTG	Natural gas	667	MMBTU/H	Volatile Organic Compounds (VOC)	Good combustion practices	5	LB/H	HOURLY; EXCEPT DURING STARTUP/SHUTDOWN	BACT-PSD		0			0		
TX-0794	BRAZOS ELECTRIC COOPERATIVE	TX	130051,PSDTX1450, GHGPSDTX131	221112	04/07/2016 ACT	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).	Simple cycle turbine	natural gas	171	MW	Volatile Organic Compounds (VOC)	Premixing of fuel and air enhances combustion efficiency and minimizes emissions.	5.4	LB/H		BACT-PSD		0			0		
*KS-0036	WESTAR ENERGY	KS	C-10656	221112	03/18/2013 ACT	The Westar Energy - Emporia Energy Center (Source ID: 1110046) is a fossil fuel power generation facility located in Emporia, Kansas.	GE LM6000PC SPRINT Simple cycle combustion turbine	Pipeline quality natural gas	405.3	MMBTU/hr	Volatile Organic Compounds (VOC)	utilize efficient combustion/design technology	5.8	LB/HR	AT FULL LOAD	BACT-PSD		0			0		
IN-0261	DUKE ENERGY INDIANA, LLC VERMILLION GENERATING STA	IN	165-36956-00022	221112	02/28/2017 ACT	ELECTRIC UTILITY SERVICES	SIMPLE CYCLE, NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	80	MW	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	17.6	LB/H	EACH TURBINE	BACT-PSD		1.76	TON/12 CONSEC. MONTH	COMPLIANCE DETERMINED END OF EACH MONTH	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*TX-0908	NEWMAN POWER STATION	EL PASO ELECTRIC COMPANY	TX	N284, PSDTX1090M1, GHGPSDTX199	221112	08/27/2021 ACT	a new natural gas simple cycle turbine along with ancillary equipment.	Simple Cycle Turbine	natural gas	230	MW	Carbon Dioxide Equivalent (CO2e)	Use of natural gas and good combustion practices	0			BACT-PSD	NSPS , MACT	0			0		
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	SIMPLE CYCLE TURBINE	NATURAL GAS	14552539	MMBTU/YR	Carbon Dioxide Equivalent (CO2e)	Low sulfur natural gas fuel	0			BACT-PSD		0			0		
IL-0121	INVENERGY NELSON EXPANSION LLC	INVENERGY	IL	15060042	221112	09/27/2016 ACT	Peaking facility at an existing major source. The expansion will consist of two simple cycle combustion turbines and a fuel heater.	Two Simple Cycle Combustion Turbines	Natural Gas	190	MW	Carbon Dioxide Equivalent (CO2e)	Turbine-generator design and proper operation	0			BACT-PSD		0			0		
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	PSD-LA-792	221210	03/21/2016 ACT	A new facility to liquefy 8.0 million metric tons per year of natural gas	Gas Turbines (8 units)	natural gas	333	mm btu/hr	Carbon Dioxide Equivalent (CO2e)	good combustion/operating/maintenance practices and fueled by natural gas; use intake air chiller	0			BACT-PSD		0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	Gas turbines (9 units)	natural gas	1069	mm btu/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices and fueled by natural gas; Use high thermal efficiency turbines	0			BACT-PSD		0			0		
LA-0349	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	LA	PSD-LA-824	221210	07/10/2018 ACT	Propose a new facility to liquefy natural gas for export	Compressor Turbines (20)	natural gas	540	mm btu/hr	Carbon Dioxide Equivalent (CO2e)	Use Low Carbon Fuel, Energy Efficiency Measures, and Good Combustion Practices	0			BACT-PSD		0			0		
*LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	LAKE CHARLES LNG EXPORT COMPANY, LLC	LA	PSD-LA-838	486210	09/03/2020 ACT	A greenfield facility to liquefy and export natural gas.	Turbines (EQT0020 - EQT0031)	Natural gas	0		Carbon Dioxide Equivalent (CO2e)	Low carbon fuels Energy efficient designs and operation	0			BACT-PSD		0			0		
TX-0851	RIO BRAVO PIPELINE FACILITY	RIO GRANDE LNG LLC	TX	140792, PSDTX1498, GHGPSDTX158	486210	12/17/2018 ACT	Natural gas processing and liquefied natural gas (LNG) export terminal	Refrigeration Compression Turbines	NATL GAS	967	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and use of pipeline quality natural gas.	0			BACT-PSD		0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	TURBINE	NATURAL GAS	0		Carbon Dioxide Equivalent (CO2e)	good combustion practices and the use of gaseous fuel	0			BACT-PSD		0			0		
VA-0326	DOSWELL ENERGY CENTER	DOSWELL LIMITED PARTNERSHIP DOSWELL ENERGY CENTER	VA	51018	221112	10/04/2016 ACT	The facility is currently composed of four Kraftwerk Union/Siemens (Model: V84.2) combined cycle turbine units each equipped with a duct burner and supporting equipment (auxiliary boiler, fire pump, emergency generator and fuel oil storage tanks) under one Prevention of Significance Deterioration (PSD) permit and one simple cycle turbine unit under another PSD permit. The combined cycle turbines	Two (2) GE 7FA simple cycle combustion turbines	Natural Gas	1961	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)	Good combustion, maintenance and use of active combustion dynamic monitoring systems.	0			BACT-PSD		0			0		
WV-0028	WAVERLY POWER PLANT	PLEASANTS ENERGY LLC	WV	R14-0034A	221112	03/13/2018 ACT	300 MW Simple-Cycle Peaking Plant	GE 7FA.004 Turbine	Natural Gas	167.8	MW	Carbon Dioxide Equivalent (CO2e)	Use of natural gas & use of GE 7FA.004	0			BACT-PSD		0			1300	LB/MW-HR	12 MONTH ROLLING AVERAGE
TX-0758	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	GHGPSDTX1366	221112	08/01/2014 ACT	Invenergy proposes to construct a 330 MW peak power plant (known as the Ector County Energy Center Plant (ECEC)), located in Goldsmith, Ector County, Texas. With this proposed project, Invenergy plans to construct two natural gas-fired simple-cycle turbines, General Electric (GE) Model 7FA.03, and associated equipment, a fire water pump engine, a natural gas-fired dew-point heater, and two circuit breakers.	Simple Cycle Combustion Turbine-MSS	Natural Gas	0		Carbon Dioxide Equivalent (CO2e)		21	TON CO2E/EVENT	EACH MSS EVENT	BACT-PSD		0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT-002 NO - Simple Cycle Combustion Turbine 1 (Normal Operations) [EQT0017]	Natural Gas	2201	MM BTU/hr	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	50	KG/GJ	ANNUAL AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	120	LB/MM BTU	ANNUAL AVERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT-002 NO - Simple Cycle Combustion Turbine 2 (Normal Operations) [EQT0018]	Natural Gas	2201	MM BTU/hr	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	50	KG/GJ	ANNUAL AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	120	LB/MM BTU	ANNUAL AVERAGE	0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,888 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISON LIMIT = 6.2 TONS/YR	2 COMBUSTION TURBINES	NATURAL GAS	130	MW	Carbon Dioxide Equivalent (CO2e)	HIGH EFFICIENCY GE 7EA CTS WITH HRSGS EQUIPPED WITH DLN1 COMBUSTORS AND EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS	117	LB/MMBTU	3-HOUR BLOCK AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and clean burning fuel (NG)	117.1	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-inch diameter	Six (6) Simple Cycle Gas-Turbines (Power Generation)	Natural Gas	386	MMBtu/hr	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and clean burning fuel (NG)	117.1	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
IN-0264	MONTPELIER GENERATING STATION	AES OHIO GENERATION, LLC	IN	179-37209-00026	221112	01/06/2017 ACT	COMBUSTION TURBINES	PRATT & TWIN-PAC SIMPLE CYCLE TURBINES	NATURAL GAS	270.9	MMBTU/H	Carbon Dioxide	NATURAL GAS AS PRIMARY FUEL; GOOD COMBUSTION PRACTICES	118	LB/MMBTU	FOR NATURAL GAS	BACT-PSD		162	LB/MMBTU	FOR FUEL OIL	0		
*AL-0329	COLBERT COMBUSTION TURBINE PLANT	TENNESSEE VALLEY AUTHORITY	AL	701-0010	221112	09/21/2021 ACT	Electric Generating Facility	Three 229 MW Simple Cycle Combustion Turbines	Natural Gas	229	MW	Carbon Dioxide		120	LB/MMBTU		BACT-PSD	NSPS	0			0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT-002 NO - Simple Cycle Combustion Turbine 1 (Startup/Shutdown/ Maintenance/Tuning	Natural Gas	2201	MM BTU/hR	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	120	LB/MM BTU	ANNUAL AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	50	KG/GJ	ANNUAL AVERAGE	0		
*LA-0327	WASHINGTON PARISH ENERGY CENTER	WASHINGTON PARISH ENERGY CENTER ONE, LLC	LA	PSD-LA-829	221112	05/23/2018 ACT	New 414 MW electric generating plant which provides electricity during peak demand. It consists of two simple-cycle turbine generators which fire natural gas only.	CT-002 NO - Simple Cycle Combustion Turbine 2 (Startup/Shutdown/ Maintenance/Tuning	Natural Gas	2201	MM BTU/hr	Carbon Dioxide Equivalent (CO2e)	Facility-wide energy efficiency measures , such as improved combustion measures, and use of pipeline quality natural gas.	120	LB/MM BTU	ANNUAL AVERAGE	BACT-PSD	NSPS , OPERATING PERMIT	50	KG/GJ	ANNUAL AVERAGE	0		
TX-0826	MUSTANG STATION	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	72579, PSDTX1080M1, GHGPSDTX13	221112	08/16/2017 ACT	GE7FA combustion turbine (Unit 6) to increase the hours of operation to 3000 hours per year. The turbine construction was completed the first quarter of 2013 and initial firing began on April 1, 2013.	Simple Cycle Turbine	NATURAL GAS	162.8	MW	Carbon Dioxide Equivalent (CO2e)	Pipeline quality natural gas and good combustion practices	120	LB/MMBTU		BACT-PSD		0			0		
NY-0106	GREENIDGE STATION	GREENIDGE GENERATION LLC	NY	8-5736-00004/00017	221112	09/07/2016 ACT	Greenidge Generation LLC has submitted a revised application for a Title V Air Permit in accordance with the requirements of Title 6 of the New York compilation of Codes, Rules, and Regulations, Part 201-6 (6 NYCRR Part 201-6). The application is for conversion of the Greenidge Electricity Generating Station, located in the Town of Torrey, Yates County to operate primarily on natural gas with up to 19%	Turbine - natural gas	natural gas	107	MW	Carbon Dioxide		130.17	LB/MMBTU	1 H	BACT-PSD		0			0		
NY-0106	GREENIDGE STATION	GREENIDGE GENERATION LLC	NY	8-5736-00004/00017	221112	09/07/2016 ACT	Greenidge Generation LLC has submitted a revised application for a Title V Air Permit in accordance with the requirements of Title 6 of the New York compilation of Codes, Rules, and Regulations, Part 201-6 (6 NYCRR Part 201-6). The application is for conversion of the Greenidge Electricity Generating Station, located in the Town of Torrey, Yates County to operate primarily on natural gas with up to 19%	Turbine - natural gas and wood	natural gas and up to 19% wood	107	MW	Carbon Dioxide		130.17	LB/MMBTU	1 H	BACT-PSD		0			0		
TX-0761	SR BERTRON ELECTRIC GENERATING STATION	NRG TEXAS POWER	TX	GHGPSDTX104, 102731, PSDTX129	221112	09/15/2015 ACT	Electric Generating Entity. The project will consist of two gas fired combustion turbines (CTGs) each equipped with a supplementary fired [duct burners (DBs)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas. The CTGs will operate in simple cycle and combined cycle modes. The gas turbines will be one of four options.	Simple cycle turbines greater than 25 megawatts (MW) firing natural gas	natural gas	359	MW	Carbon Dioxide		1232	LB /MW H		BACT-PSD	NSPS	0			0		
TX-0762	CEDAR BAYOU ELECTRIC GENERATING STATION	NRG TEXAS POWER	TX	GHGPSDTX102, 105810, PSDTX1308	221112	09/15/2015 ACT	Electric Generating Entity. The project will consist of two gas fired combustion turbines (CTGs) each equipped with a supplementary fired [duct burners (DBs)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas. The CTGs will operate in simple cycle and combined cycle modes. The gas turbines will be one of four options.	Simple cycle turbines greater than 25 megawatts (MW)	natural gas	359	MW	Carbon Dioxide		1232	LB CO2/MWH		BACT-PSD	NSPS	0			0		
TX-0757	INDECK WHARTON ENERGY CENTER	INDECK WHARTON, LLC	TX	PSD-TX-1374-GHG	221112	05/12/2014 ACT	Indeck proposes to construct a peaking power plant, the Indeck Wharton Energy Center, generally located south of Danevang, Texas. To meet the anticipated demand for peak power, Indeck proposes to construct three identical natural gas-fired F-class simple cycle combustion turbines with associated support equipment. Indeck proposes that the three new combustion turbine generators (CTGs) will be	Simple Cycle Combustion Turbine, GE 7FA.05	Pipeline Natural Gas	0		Carbon Dioxide Equivalent (CO2e)		1276	LB CO2/MWHR (GROSS)	2,500 OPERATIONAL HR ROLLING DAILY/CT	BACT-PSD		321028	TPY CO2E	12-MONTH ROLLING BASIS	0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0753	GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS, L.P.	TX	PSD-TX-1310-GHG	221112	12/02/2014 ACT	GPP proposes to add two (2) new gas-fired simple-cycle combustion turbines of 227 MW (nominal) electric generating capacity each to the 1,000 MW (nominal) existing major stationary source, Guadalupe Generating Station (GGS), located in Marion, Texas. The proposed project will provide peaking capacity at an existing natural gas fired combined cycle electric generating station. The two new natural gas-fired	Simple Cycle Combustion Turbine Generator	Pipeline Natural Gas	10673	Btu/kWh	Carbon Dioxide Equivalent (CO2e)		1293.3	LB CO2/MWHR (GROSS)	12-MONTH ROLLING AVERAGE (NORMAL OPER)	BACT-PSD		20.8	TONS CO2/HR	12-MONTH ROLLING AVERAGE BASIS (MSS OPER	0		
TX-0753	GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS, L.P.	TX	PSD-TX-1310-GHG	221112	12/02/2014 ACT	GPP proposes to add two (2) new gas-fired simple-cycle combustion turbines of 227 MW (nominal) electric generating capacity each to the 1,000 MW (nominal) existing major stationary source, Guadalupe Generating Station (GGS), located in Marion, Texas. The proposed project will provide peaking capacity at an existing natural gas fired combined cycle electric generating station. The two new natural gas-fired	Simple Cycle Combustion Turbine Generator	Pipeline Natural Gas	10673	Btu/kWh	Carbon Dioxide Equivalent (CO2e)		1293.3	LB CO2/MWHR (GROSS)	12-MONTH ROLLING AVERAGE (NORMAL OPER)	BACT-PSD		20.8	TONS CO2/HR	12-MONTH ROLLING AVERAGE BASIS (MSS OPER	0		
NY-0113	EDGEWOOD ENERGY LLC	EDGEWOOD ENERGY LLC	NY	1-4728-03244/00005	221112	07/09/2013 ACT	Edgewood Energy LLC is a power is a simple cycle combustion turbine plant located in Edgewood, Suffolk County, New York that contains two GE LM6000 combustion turbines that fire only natural gas. The facility has an optimum electrical output of 95 megawatts (MW) firing only natural gas. This electrical output represents an increase from the 79.9 MW limit. This increase was allowed through a declaratory	Turbines - NG	natural gas	0		Carbon Dioxide		1300	LB/MWH		BACT-PSD		0			0		
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	Constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the	Simple Cycle Turbine	natural gas	227.5	MW	Carbon Dioxide Equivalent (CO2e)	Pipeline quality natural gas; limited hours; good combustion practices	1300	LB/MW H		BACT-PSD	NSPS	0			0		
WV-0026	WAVERLY FACILITY	PLEASANTS ENERGY, LLC	WV	R14-0034	221112	01/23/2017 ACT	300 MW, natural gas fired, simple cycle peaking power facility	GE Model 7FA Turbine	Natural Gas	1571	mmbtu/hr	Carbon Dioxide	Use of Natural Gas, Selection of GE7FA	1300	LB/MW-HR	NATURAL GAS	BACT-PSD		1900	LB/MW-HR	FUEL OIL	1300	LB/MW-HR	NATURAL GAS
TX-0819	GAINES COUNTY POWER PLANT	SOUTHWESTERN PUBLIC SERVICE COMPANY	TX	135322, PSDTX1470, AND GHGPSDT	221112	04/28/2017 ACT	Constructed in phases, with natural gas-fired simple cycle combustion turbines (SCCTs) with dry low nitrogen oxide (NOx) burners (DLN) to be converted into 2-on-1 combined cycle combustion turbines (CCCTs) with selective catalytic reduction (SCRs), heat recovery steam generators (HRSGs, one per combustion turbine) and one steam turbine per two CCCTs. Federal control review only applies to the	Simple Cycle Turbine	natural gas	227.5	MW	Carbon Dioxide Equivalent (CO2e)	Pipeline quality natural gas; limited hours; good combustion practices	1300	LB/MW H		BACT-PSD	NSPS	0			0		
TX-0735	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	GHGPSDTX41M1	221112	05/20/2015 ACT	Golden Spread Electric Cooperative, Inc. (GSEC) is requesting PSD permits for three additional simple cycle electric generating plants at an existing site to meet increased energy demand in the area. The generating equipment consists of three new GE 7FS-Series natural gas-fired combustion turbines (CTG). Each turbine has a maximum electric output of 202 MW.	Simple Cycle Turbine & Generator	natural gas	202	MW	Carbon Dioxide Equivalent (CO2e)	Energy efficiency, good design & combustion practices	1304	LB CO2/MWHR		BACT-PSD		0			0		
TX-0824	JACKSON COUNTY GENERATING FACILITY	SOUTHERN POWER	TX	GHGPSDTX118	221112	06/30/2017 ACT	simple cycle electric generation	Simple Cycle Turbines	natural gas	920	MW	Carbon Dioxide Equivalent (CO2e)	energy efficiency designs, practices, and procedures, CT inlet air cooling, periodic CT burner maintenance and tuning, reduction in heat loss, i.e., insulation of the CT, instrumentation and controls	1316	LB/MW HR		BACT-PSD	NSPS	0			0		
CA-1223	PIO PICO ENERGY CENTER	PIO PICO ENERGY CENTER, LLC	CA	SD 11-01	221112	11/19/2012 ACT	CONSTRUCTION OF THREE GENERAL ELECTRIC (GE) LMS100 NATURAL GAS-FIRED COMBUSTION TURBINE-GENERATORS (CTGS) RATED AT 100 MW EACH. THE PROJECT WILL HAVE AN ELECTRICAL OUTPUT OF 300 MW.	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	300	MW	Carbon Dioxide Equivalent (CO2e)		1328	LB/MW-H	GROSS OUTPUT	BACT-PSD		720	H	ROLLING OPERATING HOUR AVG	0		
TX-0757	INDECK WHARTON ENERGY CENTER	INDECK WHARTON, LLC	TX	PSD-TX-1374-GHG	221112	05/12/2014 ACT	Indeck proposes to construct a peaking power plant, the Indeck Wharton Energy Center, generally located south of Danevang, Texas. To meet the anticipated demand for peak power, Indeck proposes to construct three identical natural gas-fired F-class simple cycle combustion turbines with associated support equipment. Indeck proposes that the three new combustion turbine generators (CTGs) will be	Simple Cycle Combustion Turbine, SGT-5000F(5)	Pipeline Natural Gas	0		Carbon Dioxide Equivalent (CO2e)		1337	LB CO2/MWHR (GROSS)	2500 OPERATIONAL HR ROLLING DAILY/CT	BACT-PSD		358529	TPY CO2E	12-MONTH ROLLING	0		
TX-0788	NECHES STATION	APEX TEXAS POWER LLC	TX	122401, PSDTX1428, GHGPSDTX111	221112	03/24/2016 ACT	either 4 simple cycle combustion turbine generators (CTGs) or two CTGs operating in simple cycle or combined cycle modes. The CTGs will be one of two options: Siemens or General Electric.	Large Combustion Turbines > 25 MW	natural gas	232	MW	Carbon Dioxide Equivalent (CO2e)	good combustion practiceS	1341	LB/MW H		BACT-PSD	NSPS	0			0		
FL-0354	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-013-AC	221112	08/25/2015 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Five 200-MW combustion turbines	Natural gas	2100	MMBtu/hr (approx)	Carbon Dioxide	Use of natural gas with restricted use of ULSD as backup fuel	1372	LB/MWH	NAT GAS OPERATION, 12- OR 36- MO ROLLING	BACT-PSD	NSPS	1871	LB/MWH	ULSD OPERATION, 12-OR 36- MO ROLLING	0		
FL-0355	FORT MYERS PLANT	FLORIDA POWER & LIGHT (FPL)	FL	0710002-022-AC	221112	09/10/2015 ACT	Electric power plant, consists of a 6-on-2 combined-cycle unit (Units 2A through 2F) and two modern simple-cycle combustion turbines. Primary fuel is natural gas. Also includes 12 gas turbines (63 MW each) for peaking, introduced into service in 1974. This project entails decommissioning 10 of the 12 peaking turbines. They will	Combustion Turbines	Natural gas	2262.4	MMBtu/hr gas	Carbon Dioxide Equivalent (CO2e)	Use of low-emitting fuel and efficient turbine	1374	LB CO2E / MWH	FOR NATURAL GAS OPERATION	BACT-PSD	NSPS	1874	LB CO2E / MWH	FOR ULSD OPERATION	0		
TX-0758	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	GHGPSDTX1366	221112	08/01/2014 ACT	Invenergy proposes to construct a 330 MW peak power plant (known as the Ector County Energy Center Plant (ECEC)), located in Goldsmith, Ector County, Texas. With this proposed project, Invenergy plans to construct two natural gas-fired simple-cycle turbines, General Electric (GE) Model 7FA.03, and associated equipment, a fire water pump engine, a natural gas-fired dew-point heater, and two circuit breakers.	Simple Cycle Combustion Turbine, GE 7FA.03	Natural Gas	11707	Btu/kWh (HHV)	Carbon Dioxide Equivalent (CO2e)		1393	LB CO2/MWHR (GROSS)	2500 OPERATIONAL HR ROLLING DAILY/CT	BACT-PSD		239649	TPY CO2E	12-MONTH ROLLING TOTAL	0		
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	PSC CASE NO. 9136	221119	07/01/2014 ACT	120 MEGAWATT SIMPLE CYCLE NATURAL GAS FIRED POWER PLANT PERFORMA E PROJECT-WIDE EMISSION LIMITS: PM10 = 43.0 TONS/YR PM2.5 = 43.0 TONS/YR NOX = 58.5 TONS/YR	(2) 60-MW SIMPLE CYCLE COMBUSTION TURBINES, FIRING NATURAL GAS	NATURAL GAS	120	MW	Carbon Dioxide Equivalent (CO2e)	USE OF NATURAL GAS. ENERGY EFFICIENCY DESIGN - USE OF INLET FOGGING/WET COMPRESSION, INSULATION BLANKETS TO REDUCE HEAT LOSS, AND FUEL GAS PREHEATING.	1394	LB CO2E/MWH	12-MONTH ROLLING, EXCLUDING SU/SD	BACT-PSD		0			0		
TX-0771	SHAWNEE ENERGY CENTER	SHAWNEE ENERGY CENTER, LLC	TX	GHGPSDTX126, PSDTX1442, 125963	221112	11/10/2015 ACT	Electric Generating Utility: The project will consist of four gas fired combustion turbines (CTGs). The CTGs are fueled with pipeline quality natural gas and will operate in simple cycle mode. The gas turbines will be one of two options.	Simple cycle turbines greater than 25 megawatts (MW)	natural gas	230	MW	Carbon Dioxide Equivalent (CO2e)		1398	LB/MWH		BACT-PSD	NSPS	0			0		
TX-0794	HILL COUNTY GENERATING FACILITY	BRAZOS ELECTRIC COOPERATIVE	TX	130051,PSDTX1450, GHGPSDTX131	221112	04/07/2016 ACT	Four simple cycle combustion turbine electric generators are proposed. Natural gas or ultra-low sulfur diesel fuel oil are the fuels. Turbine model options are: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemes SGT6-5000(5)ee. Electric output is between 684 and 928 megawatts (MW).	Simple cycle turbine	natural gas	171	MW	Carbon Dioxide Equivalent (CO2e)		1434	LB/MWH		BACT-PSD	NSPS	0			0		
TX-0775	CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	TX	GHGPSDTX120, 120849, AND PSDTX	221112	11/13/2015 ACT	Navasota South Peakers Operating Company II LLC proposes to install three new natural gas fired combustion turbine generators (CTGs). Each CTG will be a General Electric 7FA.04 model that can produce approximately 183 Megawatts (MW) each based upon the manufacturer's projected output at baseload operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Carbon Dioxide Equivalent (CO2e)	Low carbon fuel, good combustion, efficient combined cycle design	1461	LB/MW H		BACT-PSD	NSPS	0			0		
TX-0778	UNION VALLEY ENERGY CENTER	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	TX	GHGPSDTX117	221112	12/16/2015 ACT	three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	MW	Carbon Dioxide Equivalent (CO2e)		1461	LB/MW H		BACT-PSD	NSPS	0			0		
TX-0780	VAN ALSTYNE ENERGY CENTER	NAVASOTA NORTH PEAKERS OPERATING COMPANY I, LLC.	TX	GHGPSDTX119, 121051, PSDTX1418	221112	01/13/2016 ACT	Navasota North Peakers Operating Company I, LLC. proposes to install three new natural gas fired combustion turbine generators (CTGs). The CTGs will be the General Electric 7FA.04 (~214 megawatt (MW) each; manufacturerâ€™s output at baseload, ISO at 183 MW), operating as peaking units in simple cycle.	Simple Cycle Turbine	natural gas	183	mw	Carbon Dioxide		1461	LB/MWH		BACT-PSD	NSPS	0			0		
TX-0900	ECTOR COUNTY ENERGY CENTER	ECTOR COUNTY ENERGY CENTER LLC	TX	110423, PSDTX1366M1 GHGPSD49M1	221112	08/17/2020 ACT	increase the hours of operation for the two simple cycle gas turbines	Simple Cycle Turbines	natural gas	0		Carbon Dioxide Equivalent (CO2e)	Best management practices and good combustion practices, clean fuel	1514	LB/MWHR		BACT-PSD		0			0		
CO-0075	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	13PB2245	221112	05/30/2014 ACT	Power generation facility	Turbine - simple cycle gas	natural gas	375	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good Combustion Control	1600	LB/MW H GROSS	ROLLING 365-DAY AVE	BACT-PSD	NSPS , OPERATING PERMIT	193555	TONS PER YEAR	ROLLING 365-DAY AVE	0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS-100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Thermal efficiency Clean fuels	1707	LB OF CO2 /GROSS MWH	365-DAY ROLLING AVERAGE	BACT-PSD		0			0		
OR-0050	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	26-0235	221112	03/05/2014 ACT	Troutdale Energy Center (TEC) proposes to construct and operate a 653 megawatt (MW) electric generating plant in Troutdale, Oregon. TEC proposes to generate electricity with three natural gas-fired turbines, one of which will be a combined-cycle unit with duct burner and heat recovery steam generator.	GE LMS-100 combustion turbines, simple cycle with water injection	natural gas	1690	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Thermal efficiency Clean fuels	1707	LB OF CO2 /GROSS MWH	365-DAY ROLLING AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Carbon Dioxide	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	12666	BTU/KW-H, MINIMUM	CONTINUOUS	BACT-PSD		116.89	LB/MMBTU	3-HR AVERAGE	0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	TWO (2) NATURAL GAS FIRED COMBUSTION TURBINES	NATURAL GAS	283	MMBTU/H, EACH	Carbon Dioxide	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	12666	BTU/KW-H, MINIMUM	CONTINUOUS	BACT-PSD		116.89	LB/MMBTU	3-HR AVERAGE	0		
MI-0410	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	MI	191-12	221112	07/25/2013 ACT	Four (4) natural gas fired combined cycle combustion turbine generators (CTG) and heat recovery steam generators (HRSG) with duct burner firing capability; ancillary facility equipment.	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Efficient combustion; energy efficiency	20141	T/YR	12-MO ROLLING TIME PERIOD	BACT-PSD	N/A	0			0		

Xcel Blue Lake
RBLC Summary Tables
Simple Cycle Combustion Turbines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Carbon Dioxide Equivalent (CO2e)	Combust low carbon fuel gas, good combustion practices, good operation and maintenance practices and insulation.	134907	T/YR	ANNUAL TOTAL	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Aeroderivative Simple Cycle Combustion Turbine	Natural Gas	263	MM BTU/h	Carbon Dioxide Equivalent (CO2e)	Combust low carbon fuel gas, good combustion practices, good operation and maintenance practices and insulation.	134907	T/YR	ANNUAL TOTAL	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
TX-0679	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	GHGPSDTX123	221210	02/27/2015 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual average of approximately 2.1 billion standard cubic feet per day of pipeline-quality	Refrigeration Compressor Turbines	natural gas	40000	hp	Carbon Dioxide Equivalent (CO2e)	Install efficient turbines, follow the turbine manufacturer's emission-related written instructions for maintenance activities including prescribed maintenance intervals to assure good combustion and efficient operation. Compressors shall be inspected and	146754	TPY	ROLLING 12-MONTH BASIS	BACT-PSD		0			0		
TX-0679	CORPUS CHRISTI LIQUEFACTION PLANT	CORPUS CHRISTI LIQUEFACTION LLC	TX	GHGPSDTX123	221210	02/27/2015 ACT	Corpus Christi Liquefaction, LLC (CCL) proposes to construct and operate natural gas liquefaction and export plant and import facilities with regasification capabilities. The liquefied natural gas (LNG) terminal will be capable of processing an annual average of approximately 2.1 billion standard cubic feet per day of pipeline-quality	Refrigeration Compressor Turbine	natural gas	40000	hp	Carbon Dioxide Equivalent (CO2e)	Install efficient turbines, follow the turbine manufacturer's emission-related written instructions for maintenance activities including prescribed maintenance intervals to assure good combustion and efficient operation. Compressors shall be inspected and	146754	TPY	12-MONTH ROLLING BASIS	BACT-PSD		0			0		
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	PORT ARTHUR LNG, LLC	TX	131769, PSDTX1456, GHGPSDTX134	486210	02/17/2016 ACT	Liquefied natural gas (LNG) export terminal	Simple Cycle Electrical Generation Gas Turbines 15.210	natural gas	34	MW	Carbon Dioxide Equivalent (CO2e)	Equipment specifications & work practices - Good combustion practices and use of low carbon, low sulfur fuel	156912	T/YR		BACT-PSD		1060	LB/MW		0		
ND-0030	LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	ND	PTC 13049	221112	09/16/2013 ACT	Three natural gas fired simple cycle turbines used to generate electricity for peak power demand. The turbines are GE LM6000 PF Sprint units with a nominal capacity of 45 MW each.	Natural Gas Fired Simple Cycle Turbines	Natural gas	412	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	High efficiency turbines	220122	TONS	12 MONTH ROLLING TOTAL	BACT-PSD		0			0		
ND-0029	PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	ND	PTC 13037	221112	05/14/2013 ACT	Three GE LM6000 PC SPRINT natural gas fired turbines used to generate electricity for peak periods.	Natural gas-fired turbines	Natural gas	451	MMBTU/H	Carbon Dioxide Equivalent (CO2e)		243147	T/12 MON ROLL TOTAL	12 MONTH ROLLING TOTAL/EACH UNIT	BACT-PSD		0			0		
ND-0028	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	PTC13016	221112	02/22/2013 ACT	Addition of a natural gas-fired turbine (Unit 3) to an exisiting coal-fired power plant. The turbine will be used for supplying peak power and is rated at 986 MMBtu/hr and 88 MWe at average site conditions.	Combustion Turbine	Natural gas	986	MMBTU/H	Carbon Dioxide Equivalent (CO2e)		413198	TONS/12 MONTH	12 MONTH ROLLING TOTAL	BACT-PSD		0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Carbon Dioxide Equivalent (CO2e)	Exclusively combust low carbon fuel gas, good combustion practices, good operation and maintenance practices, and insulation	1426146	T/YR	ANNUAL TOTAL	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Simple Cycle Combustion Turbines (SCCT1 to SCCT3)	Natural Gas	927	MM BTU/h	Carbon Dioxide Equivalent (CO2e)	Exclusively combust low carbon fuel gas, good combustion practices, good operation and maintenance practices, and insulation	1426146	T/YR	ANNUAL TOTAL	BACT-PSD	NSPS , OPERATING PERMIT	0			0		
TX-0816	CORPUS CHRISTI LIQUEFACTION	CORPUS CHRISTI LIQUEFACTION STAGE III, LLC	TX	139479, PSDTX1496, GHGPSDTX157	221210	02/14/2017 ACT	Trains 4 and 5 will consist of 12 natural gas compressor turbines, 2 thermal oxidizers, 2 sets of flares each comprised of one wet gas flare and one dry gas flare, 2 amine surge tanks (maintenance, startup, and shutdown [MSS] only), 3 diesel generators, 3 fire-water pump diesel engines, 6 fixed roof diesel storage tanks, and piping components.	Refrigeration compressor turbines	NATURAL GAS	40000	HP	Carbon Dioxide Equivalent (CO2e)		1793574	T/YR		BACT-PSD		0			0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and	Six Simle Cycle Gas-Fired Turbines	Natural Gas	1113	MMBtu/hr	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and burning clean fuels (natural gas)	117.1	LB/MMBTU	3-HOURS	BACT-PSD		0			0		
*AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	07/07/2022 ACT	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaskaâ€™s North Slope to be shipped to outside markets. The stationary source will consist of structures and	Four Combined Cycle Gas-Fired Turbines	Natural Gas	384	MMBtu/hr	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and burning clean fuels (natural gas)	117.1	LB/MMBTU	3-HOURS	BACT-PSD		0			0		

Attachment I.2-2

Engine Generator RBLC

Attachment I.2-2 Engine Generator RBLC

Xcel Energy
RBLC Summary Tables
Engine Generators

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*PA-0292	ML 35 LLC/PHILA CYBERCENTER	ML 35 LLC	PA	09-0142B	518210	06/01/2012 ACT	installation of five (5) 2 MW electric generators with the associated storage tanks and air pollution control devices including Selective Catalytic Reduction (SCR) system and oxidation catalysts; conversion of 6 existing emergency generators to peak shaving generators; and a Facilitywide NOx Emissions Cap.	DIESEL GENERATOR (2.25 MW EACH) - 5 UNITS	#2 Oil	0		Particulate matter, total (TPM)		0.28	LB/H		OTHER CASE-BY-CASE	OTHER	0.03	T/YR	AS A 12-MONTH ROLLING	0		
AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	211111	08/20/2012 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY	Combustion of Diesel by ICEs	ULSD	1750	kW	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.2	G/KW-H		BACT-PSD	NSPS	0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will include the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Main Propulsion Engines	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	0.24	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will include the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Main Propulsion Engines	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	0.24	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Main Propulsion Generator Diesel Engines	Diesel	9910	hp	Particulate matter, total < 10 Âµ (TPM10)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0.24	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Main Propulsion Generator Diesel Engines	Diesel	9910	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0.24	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, total (TPM)	Clean Fuel and Good Combustion Practices	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.13	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, total < 10 Âµ (TPM10)	Clean Fuel and Good Combustion Practices	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.13	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Clean Fuel and Good Combustion Practices	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.13	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, total (TPM)	Clean Fuel and Good Combustion Practices	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.13	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, total < 10 Âµ (TPM10)	Clean Fuel and Good Combustion Practices	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.13	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, filterable < 10 Âµ (FPM10)	Clean Fuel and Good Combustion Practices	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Clean Fuel and Good Combustion Practices	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, filterable (FPM)	Clean Fuel and Good Combustion Practices	0.15	G/KW-HR (ULSD)		BACT-PSD		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, filterable < 10 Âµ (FPM10)	Clean Fuel and Good Combustion Practices	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 11 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Clean Fuel and Good Combustion Practices	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0			0		
NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	3-1326-00275/00009	221112	02/03/2016 ACT	Cricket Valley Energy Center LLC (CVEC) constructed the Cricket Valley Energy Center (the Facility), a nominal net 1,000-megawatt (MW) combined-cycle gas turbine electric generating facility, on a site located in Dover, Dutchess County, New York.	Black start generator	ultra low sulfur diesel	3000	KW	Particulate matter, filterable (FPM)	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.15	G/BHP-H	1 H	BACT-PSD		0			0		
LA-0251	FLOPAM INC. FACILITY	FLOPAM INC.	LA	PSD-LA-747(M1)	325998	04/26/2011 ACT	A CHEMICAL MANUFACTURING COMPLEX IS UNDER CONSTRUCTION (FJSD-LA-747 - LA0240). EQUIPMENT IS ADDED OR REDESIGNED. (ENGINES, COOLING TOWERS, MATERIAL HANDLING). PERMIT PSD-LA-747(M2) WAS ISSUED JULY 5, 2012 FOR ADDITIONAL DUST	Large Generator Engines (17 units)	Diesel	0		Particulate matter, filterable < 10 Âµ (FPM10)		0.01	LB/H		BACT-PSD	NSPS	0			0.2	G/KW-H	
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - C.R. Luigs	Diesel	5875	hp	Particulate matter, filterable < 10 Âµ (FPM10)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	0.24	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - C.R. Luigs	Diesel	5875	hp	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	0.24	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will include the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Main Propulsion Engines	Diesel	0		Particulate matter, filterable (FPM)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	0.43	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - Development Driller 1	Diesel	0		Particulate matter, filterable (FPM)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation,	0.43	G/KW-H	24-HOUR ROLLING ENGINE LOADS >55%	BACT-PSD	OPERATING PERMIT	0.57	G/KW-H	24-HOUR ROLLING ENGINE LOADS <55%	0		

Xcel Energy
RBLC Summary Tables
Engine Generators

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - Development Driller 1	Diesel	0		Particulate matter, filterable < 10 Âµ (FPM10)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation,	0.43	G/KW-H	24-HOUR ROLLING ENGINE LOADS >55%	BACT-PSD	OPERATING PERMIT	0.57	G/KW-H	24-HOUR ROLLING ENGINE LOADS <55%	0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - C.R. Luigs	Diesel	5875	hp	Particulate matter, filterable (FPM)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	0.43	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
AK-0072	DUTCH HARBOR POWER PLANT	CITY OF UNALASKA	AK	AQ0215CPT03	221112	07/14/2011 ACT	Rural diesel-electric power plant	EU 15 Caterpillar C-280-16	ULSD	4400	KW	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Positive Crankcase Ventilation Installed as part of the design	0.5	G/KW-H	INSTANTANEOUS	BACT-PSD	NSPS	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - Development Driller 1	Diesel	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation,	0.57	G/KW-H	24-HOUR ROLLING ENGINE LOADS <55%	BACT-PSD	OPERATING PERMIT	0.43	G/KW-H	24-HOUR ROLLING ENGINE LOADS >55%	0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGNG2	NATURAL GAS	6000	HP	Particulate matter, total < 10 Âµ (TPM10)	Burn pipeline quality natural gas.	0.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGNG2	NATURAL GAS	6000	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Burn pipeline quality natural gas.	0.5	LB/H	HOURLY	BACT-PSD	SIP	0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 1 and 2)	Diesel	0		Particulate matter, total (TPM)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 1 and 2)	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 1 and 2)	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 3 and 4)	Diesel	0		Particulate matter, total (TPM)	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	1.3	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 3 and 4)	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 3 and 4)	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	Diesel	0		Particulate matter, total (TPM)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	0.41	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	0.25	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	0.25	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Wireline Unit Diesel Engines - Development Driller 1	Diesel	0		Particulate matter, total (TPM)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	0.6	TONS	PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit, the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Wireline Diesel Engines	Diesel	0		Particulate matter, total (TPM)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	LA	PSD-LA-747(M5)	325998	01/07/2016 ACT	an existing chemical manufacturing facility	Diesel Engines		0		Particulate matter, total < 10 Âµ (TPM10)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		

Xcel Energy
RBLC Summary Tables
Engine Generators

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR) and Good Combustion Practices	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.08	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction (SCR) and Good Combustion Practices	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.08	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
*PA-0292	ML 35 LLC/PHILA CYBERCENTER	ML 35 LLC	PA	09-0142B	518210	06/01/2012 ACT	Installation of five (5) 2 MW electric generators with the associated storage tanks and air pollution control devices including Selective Catalytic Reduction (SCR) system and oxidation catalysts; conversion of 6 existing emergency generators to peak shaving generators; and a Facilitywide NOx Emissions Cap.	DIESEL GENERATOR (2.25 MW EACH) - 5 UNITS	#2 Oil	0		Nitrogen Oxides (NOx)	SCR	0.67	GRAMS/KW-H		OTHER CASE-BY-CASE	OTHER	0.41	T/YR	12-MONTH ROLLING SUM	0		
NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	3-1326-00275/00009	221112	02/03/2016 ACT	Center (the Facility), a nominal net 1,000-megawatt (MW) combined-cycle gas turbine electric generating facility, on a site located in Dover, Dutchess County, New York. The Facility consists of three General Electric (GE) Model 7FA.05 combustion turbine generators (CTGs) operating in combined-cycle mode with supplemental firing of the heat recovery steam generators (HRSGs); natural gas will be the sole	Black start generator	ultra low sulfur diesel	3000	KW	Nitrogen Oxides (NOx)	Generator equipped with selective catalytic reduction. Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.11	G/BHP-H	1 H	LAER		0			0		
AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	211111	08/20/2012 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY	Combustion of Diesel by ICEs	ULSD	1750	kW	Nitrogen Oxides (NOx)		6.4	G/KW-H		BACT-PSD	NSPS	0			0		
LA-0251	FLOPAM INC. FACILITY	FLOPAM INC.	LA	PSD-LA-747(M1)	325998	04/26/2011 ACT	A CHANGE IN EMISSIONS COMPLEX IS UNDER CONSTRUCTION (PSD-LA-747 - LA0240). EQUIPMENT IS ADDED OR REDESIGNED. (ENGINES, COOLING TOWERS, MATERIAL HANDLING). PERMIT PSD-LA-747(M2) WAS ISSUED JULY 5, 2012 FOR ADDITIONAL DUST	Large Generator Engines (17 units)	Diesel	0		Nitrogen Oxides (NOx)		6.32	LB/H	(591 HP UNITS)	LAER	NSPS	10.36	LB/H	(1175 HP UNITS)	6.4	G/KW-H	(NOX + NMHC)
AK-0072	DUTCH HARBOR POWER PLANT	CITY OF UNALASKA	AK	AQ0215CPT03	221112	07/14/2011 ACT	Rural diesel-electric power plant	EU 15 Caterpillar C-280-16	ULSD	4400	KW	Nitrogen Oxides (NOx)	Engine has turbo charger and after cooler installed as part of the design	9.8	G/KW-H	INSTANTANEOUS	BACT-PSD	NSPS	0			0		
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	ANADARKO PETROLEUM, INC.	FL	OCS-EPA-R4019	213111	12/31/2014 ACT	The facility consists of the BlackHawk drillship owned by Diamond Offshore Drilling Inc., and associated support vessels. The support vessels may include a combination of supply boats, anchor handling boats, tug boats, barges, stimulation vessels and well evaluation vessels. The proposed project will consist of three phases: the drilling phase, the well completion phase, and the	Main Propulsion Generator Engines	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices based on the most recent manufacturer's specifications issued for these engines at the time that the engines are operating under this permit	0			BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - Development Driller 1	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation,	12.1	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0327	ANADARKO - PHEONIX PROSPECT	ANADARKO PETROLEUM COMPANY	FL	OCS-EPA-R4005	213112	06/13/2011 ACT	The proposed project, known as the Phoenix Prospect, will mobilize the Discoverer Spirit, a work boat, a crew boat and a anchor handling boat to drill a single exploration well on the OCS in Lloyd Ridge Lease Block 410 to determine if natural gas reserves are present in this location. The well's objective depth is 16,100 feet true vertical depth sub-sea or 6,300 feet below the mud line of the	Main Propulsion Engines	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion and maintenance practices, Power Management System, and NOx Concentration Maintenance System as described in the OCS permit application.	12.7	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Main Propulsion Engines	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	12.7	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Main Propulsion Generator Diesel Engines	Diesel	9910	hp	Nitrogen Oxides (NOx)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	12.7	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - C.R. Luigs	Diesel	5875	hp	Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation,	18.1	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	MURPHY EXPLORATION & PRODUCTION CO.	FL	OCS-EPA-R4009	213111	05/15/2012 ACT	The facility consists of the dynamically positioned, ultra-deepwater, drilling vessel Ocean Confidence and an associated support fleet to conduct exploratory drilling and well completion for up to 90 calendar days within a two year period at a single well location within its Lloyd Ridge lease block 317. The drill site is located on the OCS in the Gulf of Mexico, approximately 135 miles	Main Propulsion Generators	Diesel	4425	hp	Nitrogen Oxides (NOx)	Use of engine with turbo charger, with after cooler, an enhanced work practice power management, NOx emissions maintenance system, and good combustion and maintenance practices based on the current manufacturer's specifications for each engine	26	G/KW-H	ROLLING 24-HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 1 and 2)	Diesel	0		Nitrogen Oxides (NOx)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturer's specifications for this engine.	9.5	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 3 and 4)	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices, based on the current manufacturer's specifications for this engine	9.7	T/YR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	9.5	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Wireline Unit Diesel Engines - Development Driller 1	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	8.92	TONS	PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - C.R. Luigs	diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	8.69	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Wireline Diesel Engines	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	PSD-LA-792	221210	03/21/2016 ACT	A new facility to liquefy 8.0 million metric tons per year of natural gas	Diesel Engines	Diesel	0		Nitrogen Oxides (NOx)	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	LA	PSD-LA-747(M5)	325998	01/07/2016 ACT	an existing chemical manufacturing facility	Diesel Engines		0		Nitrogen Oxides (NOx)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		

Xcel Energy
RBLC Summary Tables
Engine Generators

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AK-0084	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Carbon Monoxide	Oxidation Catalyst and Maintain Good Combustion Practices	0.18	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.12	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Carbon Monoxide	Oxidation Catalyst and Maintain Good Combustion Practices	0.18	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.12	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
FL-0347	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Main Propulsion Generator Diesel Engines	Diesel	9910	hp	Carbon Monoxide	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0.8	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - Development Driller 1	Diesel	0		Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive	1.98	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - C.R. Luigs	Diesel	5875	hp	Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the	2.42	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0328	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The	Main Propulsion Engines	Diesel	0		Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the	3.3	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
NY-0103	CRICKET VALLEY ENERGY CENTER LLC	NY	3-1326-00275/00009	221112	02/03/2016 ACT	Cricket Valley Energy Center LLC (CVEC) constructed the Cricket Valley Energy Center (the Facility), a nominal net 1,000-megawatt (MW) combined-cycle gas turbine electric generating facility, on a site located in Dover, Dutchess County, New York.	Black start generator	ultra low sulfur diesel	3000	KW	Carbon Monoxide	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	2.6	G/BHP-H	1 H	BACT-PSD		0			0		
AK-0076	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	211111	08/20/2012 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY	Combustion of Diesel by ICEs	ULSD	1750	kW	Carbon Monoxide		3.5	G/KW-H		BACT-PSD	NSPS	0			0		
*PA-0292	ML 35 LLC	PA	09-0142B	518210	06/01/2012 ACT	Installation of five (5) 2 MW electric generators with the associated storage tanks and air pollution control devices including Selective Catalytic Reduction (SCR) system and oxidation catalysts; conversion of 6 existing emergency generators to peak shaving generators; and a Facilitywide NOx Emissions Cap.	DIESEL GENERATOR (2.25 MW EACH) - 5 UNITS	#2 Oil	0		Carbon Monoxide	CO Oxidation Catalyst	3.5	GRAMS/KW-H		OTHER CASE-BY-CASE	OTHER	0.04	T/YR	12-MONTH ROLLING	0		
*TX-0915	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	DIESEL GENERATOR	DIESEL	0		Carbon Monoxide	LIMITED 500 HR/YR OPERATION	2.61	G/HPHR		BACT-PSD		0			0		
*AK-0085	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of the integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42	One (1) Black Start Generator Engine	ULSD	186.6	gph	Carbon Monoxide	Oxidation Catalyst, Good Combustion Practices, and 500 hour limit per year.	3.3	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NESHAP , NSPS	0			0		
*MI-0441	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGNG2	NATURAL GAS	6000	HP	Carbon Monoxide	Burn natural gas and be NSPS compliant.	4	G/HP-H	HOURLY	BACT-PSD	NSPS	540	PPM	PPMVD AT 15%O2; HOURLY	0		
FL-0328	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The	Crane Engines (units 1 and 2)	Diesel	0		Carbon Monoxide	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	11.8	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The	Crane Engines (units 3 and 4)	Diesel	0		Carbon Monoxide	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	4	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	Diesel	0		Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel	3.73	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Wireline Unit Diesel Engines - Development Driller 1	Diesel	0		Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	2.9	TONS	PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - C.R. Luigs	diesel	0		Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel	3.3	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Wireline Diesel Engines	Diesel	0		Carbon Monoxide	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0307	MAGNOLIA LNG, LLC	LA	PSD-LA-792	221210	03/21/2016 ACT	A new facility to liquefy 8.0 million metric tons per year of natural gas	Diesel Engines	Diesel	0		Carbon Monoxide	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
LA-0318	FLOPAM, INC.	LA	PSD-LA-747(M5)	325998	01/07/2016 ACT	an existing chemical manufacturing facility	Diesel Engines		0		Carbon Monoxide	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		

Xcel Energy
RBLC Summary Tables
Engine Generators

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
NY-0103	CRICKET VALLEY ENERGY CENTER	CRICKET VALLEY ENERGY CENTER LLC	NY	3-1326-00275/00009	221112	02/03/2016 ACT	Cricket Valley Energy Center LLC (CVEC) constructed the Cricket Valley Energy Center (the Facility), a nominal net 1,000-megawatt (MW) combined-cycle gas turbine electric generating facility, on a site located in Dover, Dutchess County, New York.	Black start generator	ultra low sulfur diesel	3000	KW	Volatile Organic Compounds (VOC)	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.	0.11	G/BHP-H	1 H	LAER		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Volatile Organic Compounds (VOC)	Oxidation Catalyst and Good Combustion Practices	0.21	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.09	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Volatile Organic Compounds (VOC)	Oxidation Catalyst and Good Combustion Practices	0.21	G/KW-HR (ULSD)	3-HOUR AVERAGE	BACT-PSD		0.09	G/KW-HR (NATURAL GAS	3-HOUR AVERAGE	0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Main Propulsion Generator Diesel Engines	Diesel	9910	hp	Volatile Organic Compounds (VOC)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0.35	G/KW-H	ROLLING 24 HOUR AVERAGE	BACT-PSD	OPERATING PERMIT	0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Main Propulsion Engines	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine	0.39	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - C.R. Luigs	Diesel	5875	hp	Volatile Organic Compounds (VOC)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine	0.39	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - Development Driller 1	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine	0.62	G/KW-H	24-HOUR ROLLING ENGINE LOADS <55%	BACT-PSD	OPERATING PERMIT	0.5	G/KW-H	24-HOUR ROLLING ENGINE LOADS >55%	0		
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	DIESEL GENERATOR	DIESEL	0		Volatile Organic Compounds (VOC)	LIMITED 500 HR/YR OPERATION	0.5	G/HPHR		BACT-PSD		0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGNG2	NATURAL GAS	6000	HP	Volatile Organic Compounds (VOC)	Burn natural gas and be NSPS compliant.	1	G/HP-H	HOURLY	BACT-PSD	NSPS	86	PPM	PPMVD AT 15%O2; HOURLY	0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 1 and 2)	Diesel	0		Volatile Organic Compounds (VOC)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	1.3	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 3 and 4)	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	1.5	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high	0.57	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Wireline Unit Diesel Engines - Development Driller 1	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection	1.17	TONS	PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Wireline Diesel Engines	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engine and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	PSD-LA-792	221210	03/21/2016 ACT	A new facility to liquefy 8.0 million metric tons per year of natural gas	Diesel Engines	Diesel	0		Volatile Organic Compounds (VOC)	good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
LA-0318	FLOPAM FACILITY	FLOPAM, INC.	LA	PSD-LA-747(MS)	325998	01/07/2016 ACT	an existing chemical manufacturing facility	Diesel Engines		0		Volatile Organic Compounds (VOC)	Complying with 40 CFR 60 Subpart IIII	0			LAER		0			0		

Xcel Energy
RBLC Summary Tables
Engine Generators

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Main Propulsion Engines	Diesel	0		Carbon Dioxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	700	G/KW-H	24-HOUR ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - C.R. Luigs	Diesel	5875	hp	Carbon Dioxide Equivalent (CO2e)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system and the Diesel Engines with	705	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Main Propulsion Engines - Development Driller 1	Diesel	0		Carbon Dioxide Equivalent (CO2e)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, and additional enhanced work practice standards including an engine performance management system, positive crankcase ventilation,	829	G/KW-H	24-HOUR ROLLING	BACT-PSD	OPERATING PERMIT	0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGNG2	NATURAL GAS	6000	HP	Carbon Dioxide Equivalent (CO2e)	Burn pipeline quality natural gas.	1171	T/YR	12-MONTH ROLLING TIME PERIOD	BACT-PSD		0			0		
AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	211111	08/20/2012 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY	Combustion of Diesel by ICEs	ULSD	1750	kW	Carbon Dioxide	Good Combustion Practices and 40 CFR 60 Subpart IIII requirements	0			BACT-PSD		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Carbon Dioxide Equivalent (CO2e)	Good Cumbustion Practices	1299630	TPY (ULSD)		BACT-PSD		869621	TPY (NATURAL GAS)		0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The GTP will treat the Point Thomson Unit (PTU) as part of the integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	One (1) Black Start Generator Engine	ULSD	186.6	gph	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and limit operation to 500 hours per year	163.6	LB/MMBTU	3-HOUR AVERAGE	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 1 and 2)	Diesel	0		Carbon Dioxide	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	722	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Crane Engines (units 3 and 4)	Diesel	0		Carbon Dioxide	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	687	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Cementing and Nitrogen Pump Diesel Engines - Development Driller 1	Diesel	0		Carbon Dioxide Equivalent (CO2e)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger, and high pressure fuel injection with aftercooler	715.5	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Wireline Unit Diesel Engines - Development Driller 1	Diesel	0		Carbon Dioxide Equivalent (CO2e)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, turbocharger with aftercooler, high pressure fuel injection with aftercooler	536.6	TONS	PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
LA-0307	MAGNOLIA LNG FACILITY	MAGNOLIA LNG, LLC	LA	PSD-LA-792	221210	03/21/2016 ACT	A new facility to liquefy 8.0 million metric tons per year of natural gas	Diesel Engines	Diesel	0		Carbon Dioxide Equivalent (CO2e)	good combustion/operating/maintenance practices	0			BACT-PSD		0			0		
OH-0359	DTE MARIETTA	DTE ENERGY	OH	P0115137	221119	03/31/2014 ACT	The newly installed DTE facility includes an 8.4 MW NG fired combustion turbine (83 MMbtu/hr) connected to a 130 MMbtu/hr NG fired HRSG. The cogeneration facility provides electricity and steam to an existing Solvay Specialty Polymers USA, LLC facility. The new DTE facility also includes two 96.5 MMBtu/hr auxiliary boilers for back-up steam. A diesel fired black start generator was also installed	black start generator w/ 1,141 hp diesel engine (P002)	diesel fuel	1141	HP	Carbon Dioxide Equivalent (CO2e)	Fuel efficient engine (good combustion practices)	65.3	T/YR		BACT-PSD		0			0		
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	DIESEL GENERATOR	DIESEL	0		Carbon Dioxide Equivalent (CO2e)	LIMITED 500 HR/YR OPERATION	0			BACT-PSD		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	Diesel and Natural Gas	143.5	MMBtu/hr	Carbon Dioxide Equivalent (CO2e)	Good Cumbustion Practices	1299630	TPY (ULSD)		BACT-PSD		869621	TPY (NATURAL GAS)		0		

Attachment I.2-3

Emergency Generator RBLC

Attachment I.2-3 Emergency Generator RBLC

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Particulate matter, total < 10 Âµ (TPM10)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.02	G/KW-H		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.02	GR/KW-H		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Particulate matter, filterable (FPM)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.02	G/KW-H		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATORS	DIESEL	1500	KW	Particulate matter, filterable (FPM)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.02	G/KW-H		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Particulate matter, filterable (FPM)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.02	G/KW-HR		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.02	G/KW-HR		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.02	G/KW-HR		BACT-PSD		0			0		
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	1.1	LB/H		BACT-PSD	NSPS	0.055	T/YR	PER ROLLING 12 MONTH PERIOD	0.015	G/BHP-H	SEE NOTES
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	08Â-00045A	221112	10/10/2012 ACT		Emergency Generator	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)		0.02	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.06	LB/H		0		
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	08Â-00045A	221112	10/10/2012 ACT		Emergency Generator	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.02	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.06	LB/H		0		
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW (P103 and	EMERGENCY GENERATOR-ENGINE	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)		0.02	GM/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.06	LB/H		0.01	T/YR	
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW (P103 and	EMERGENCY GENERATOR-ENGINE	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.02	GM/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.06	LB/H		0.01	T/YR	
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	DIESEL GENERATOR	DIESEL	0		Particulate matter, filterable (FPM)	LIMITED 500 HR/YR OPERATION	0.022	G/HPHR		BACT-PSD		0			0		
*TX-0915	UNIT 5	NRG CEDAR BAYOU LLC	TX	160538, PSDTX1528, GHGPSDTX204	221112	03/17/2021 ACT	UNIT 5	DIESEL GENERATOR	DIESEL	0		Particulate matter, filterable < 10 Âµ (FPM10)	LIMITED 500 HR/YR OPERATION	0.022	G/HPHR		BACT-PSD		0			0		
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	P0125024	331111	02/06/2019 ACT	Merchant Pig Iron Production	Emergency Generators (P005 and P006)	Diesel fuel	3131	HP	Particulate matter, filterable < 10 Âµ (FPM10)	Tier IV engine Good combustion practices	0.15	LB/H		BACT-PSD	NSPS	0.01	T/YR		0.022	G/BHP-H	
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	P0125024	331111	02/06/2019 ACT	Merchant Pig Iron Production	Emergency Generators (P005 and P006)	Diesel fuel	3131	HP	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Tier IV engine Good combustion practices	0.15	LB/H		BACT-PSD	NSPS	0.01	T/YR		0.022	G/BHP-H	
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Emergency Generator (P009)	Diesel fuel	5000	HP	Particulate matter, total < 10 Âµ (TPM10)	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.2	LB/H		BACT-PSD	NSPS	0.01	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Emergency Generator (P009)	Diesel fuel	5000	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0.2	LB/H		BACT-PSD	NSPS	0.01	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	2000 kW Emergency Generator	Ultra-low sulfur Diesel	0		Particulate matter, filterable (FPM)		0.025	GM/HP-HR		BACT-PSD		0.004	TONS	12-MONTH ROLLING BASIS	0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	2000 kW Emergency Generator	Ultra-low sulfur Diesel	0		Particulate matter, total < 10 Âµ (TPM10)		0.025	GM/HP-HR		BACT-PSD		0.004	TONS	12-MONTH ROLLING BASIS	0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	2000 kW Emergency Generator	Ultra-low sulfur Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.025	GM/HP-HR		BACT-PSD		0.004	TONS	12-MONTH ROLLING BASIS	0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATORS	DIESEL	1500	KW	Particulate matter, total < 10 Âµ (TPM10)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.04	G/KW-H		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATORS	DIESEL	1500	KW	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.04	G/KW-H		BACT-PSD		0			0		
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	NY	3-3356001 36/00001	221112	08/01/2013 ACT	CPV Valley Energy Center is a 680 MW combined cycle electric generating facility located in Middletown, NY. The combustion turbines are rated at 2,234 MMBTU/H firing natural gas and 2,145 MMBTU/H firing diesel fuel. The duct burners are rated for 500 MMBTU/H firing natural gas. In addition to the turbines their emission limits for the auxiliary boiler (73.5 MMBTU/H),	Emergency generator	ultra low sulfur diesel	0		Particulate matter, filterable (FPM)	Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.	0.03	G/BHP-H	1 H	BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	210-18	221112	08/21/2019 ACT	New power plant	FGEMENGINE	Diesel	1100	KW	Particulate matter, total (TPM)	Good combustion practices and ultra low sulfur diesel	0.04	G/HP-H	HOURLY; EACH ENGINE	BACT-PSD	NSPS	0			0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Emergency Generator		0		Particulate matter, total (TPM)		0.04	G/HP-HR		BACT-PSD	NSPS	0.003	TPY	12-MONTH ROLLING BASIS	0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Emergency Generator		0		Particulate matter, total < 10 Âµ (TPM10)		0.04	G/HP-HR		BACT-PSD	NSPS	0.003	TPY	12-MONTH ROLLING BASIS	0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Emergency Generator		0		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.04	G/HP-HR		BACT-PSD	NSPS	0.003	TPY	12-MONTH ROLLING BASIS	0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	One (1) Black Start Generator Engine	ULSD	186.6	gph	Particulate matter, total (TPM)	Good combustion practices, ULSD, and limit operation to 500 hours per year.	0.045	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	One (1) Black Start Generator Engine	ULSD	186.6	gph	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices, ULSD, and limit operation to 500 hours per year.	0.045	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	One (1) Black Start Generator Engine	ULSD	186.6	gph	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices, ULSD, and limit operation to 500 hours per year.	0.045	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	81-11	221112	11/17/2011 ACT	Utility--Natural gas fired combustion turbine	Diesel fuel-fired combustion engine (RICE)	Diesel	732	HP	Particulate matter, filterable (FPM)	Good combustion practices	0.05	G/HP-H	TEST	BACT-PSD	NSPS , NESHAP , OTHER	0			0		
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Emergency Generator	distillate fuel oil	3755	HP	Particulate matter, filterable (FPM)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.1	G/KW-H		BACT-PSD		0			0		
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Emergency Generator	distillate fuel oil	3755	HP	Particulate matter, total < 10 Âµ (TPM10)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.1	G/KW-H		BACT-PSD		0			0		
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Emergency Generator	distillate fuel oil	3755	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.1	G/KW-H		BACT-PSD		0			0		
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	08Â-0004SA	221112	10/10/2012 ACT		Fire Pump	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)		0.09	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.09	LB/H		0		
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	08Â-0004SA	221112	10/10/2012 ACT		Fire Pump	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.09	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.09	LB/H		0		
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW (P103 and	Fire Pump Engine - 460 BHP	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)		0.09	G/HP-H		OTHER CASE-BY-CASE	OTHER	0.09	LB/H		0.01	T/YR	
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW (P103 and	Fire Pump Engine - 460 BHP	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)		0.09	G/HP-H		OTHER CASE-BY-CASE	OTHER	0.09	LB/H		0.01	T/YR	
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	Fire pump engine	Ultra-low sulfur diesel	15	gal/hr	Particulate matter, filterable (FPM)		0.11	GM/HP-HR		BACT-PSD		0.002	TONS	12-MONTH ROLLING BASIS	0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	Fire pump engine	Ultra-low sulfur diesel	15	gal/hr	Particulate matter, total < 10 Âµ (TPM10)		0.11	GM/HP-HR		BACT-PSD		0.002	TONS	12-MONTH ROLLING BASIS	0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	Fire pump engine	Ultra-low sulfur diesel	15	gal/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.11	GM/HP-HR		BACT-PSD		0.002	TONS	12-MONTH ROLLING BASIS	0		
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT		WI	18-JJW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Particulate matter, total (TPM)	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	0.17	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT		WI	18-JJW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Particulate matter, total < 10 Âµ (TPM10)	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	0.17	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT		WI	18-JJW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	0.17	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	SIO INTERNATIONAL	WI	18-JJW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Particulate matter, total < 10 Âµ (TPM10)	Good Combustion Practices and The Use of Ultra-low Sulfur Fuel	0.17	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	SIO INTERNATIONAL	WI	18-JJW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Good Combustion Practices and The Use of Ultra-low Sulfur Fuel	0.17	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
KY-0109	FRITZ WINTER NORTH AMERICA, LP	FRITZ WINTER NORTH AMERICA, LP	KY	V-16-022 R1	331511	10/24/2016 ACT	This facility consists of a gray iron foundry, casting, and machining operation that produces automotive parts in Simpson County, Kentucky. The facility comprises an approximately 95 acre site, consisting of scrap handling and preparation equipment, melt furnaces, sand and mineral storage, mixing and handling equipment, mold and core	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	Diesel	53.6	gal/hr	Particulate matter, total < 2.5 Âµ (TPM2.5)	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	BACT-PSD	MACT , OPERATING PERMIT	0.298	G/HP-HR (EU74)	REQ. MANUFACTURER'S CERT.	0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
KY-0109	FRITZ WINTER NORTH AMERICA, LP	FRITZ WINTER NORTH AMERICA, LP	KY	V-16-022 R1	331511	10/24/2016 ACT	This facility consists of a gray iron foundry, casting, and machining operation that produces automotive parts in Simpson County, Kentucky. The facility comprises an approximately 95 acre site, consisting of scrap handling and preparation equipment, melt furnaces, sand and mineral storage, mixing and handling equipment, mold and core	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	Diesel	53.6	gal/hr	Particulate matter, filterable (FPM)	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	BACT-PSD	MACT , OPERATING PERMIT	0.298	G/HP-HR (EU74)	REQ. MANUFACTURER'S CERT.	0		
KY-0109	FRITZ WINTER NORTH AMERICA, LP	FRITZ WINTER NORTH AMERICA, LP	KY	V-16-022 R1	331511	10/24/2016 ACT	This facility consists of a gray iron foundry, casting, and machining operation that produces automotive parts in Simpson County, Kentucky. The facility comprises an approximately 95 acre site, consisting of scrap handling and preparation equipment, melt furnaces, sand and mineral storage, mixing and handling equipment, mold and core	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	Diesel	53.6	gal/hr	Particulate matter, total < 10 Âµ (TPM10)	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	BACT-PSD	MACT , OPERATING PERMIT	0.298	G/HP-HR (EU74)	REQ. MANUFACTURER'S CERT.	0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Particulate matter, filterable (FPM)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	PSD-FL-416, 0550063-001-AC	221119	09/23/2011 ACT	THIS PROJECT INVOLVES THE CONSTRUCTION OF A SUGARCANE AND SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY WITH A MAXIMUM ANNUAL ETHANOL (C2H5OH) PRODUCTION RATE OF 36 MILLION GALLONS PER YEAR (MGPY). THE CANE (I.E. THE SUGARCANE AND SORGHUM) WILL BE GROWN ON NEARBY FARMLAND. THE JUICE WILL BE SQUEEZED FROM THE FEEDSTOCK	2000 KW Emergency Equipment		0		Particulate matter, total (TPM)	See Pollutant Notes.	0.2	G/KW-H		BACT-PSD	NSPS	0			0		
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	FLORIDA POWER & LIGHT	FL	0930117-001-AC	221112	03/09/2016 ACT	Fossil-fueled power plant, consisting of a 3-on-1 combined cycle unit and auxiliary equipment. The combined cycle unit consists of three GE 7HA.02 turbines, each with nominal generating capacity of 350 MW. The total generating capacity for the combined cycle unit is 1,600 MW.	Three 3300-kW ULSD emergency generators	ULSD	0		Particulate matter, total (TPM)	Use of clean fuel	0.2	G / KW-HR		BACT-PSD	NSPS	0			0		
*FL-0363	DANIA BEACH ENERGY CENTER	FLORIDA POWER AND LIGHT COMPANY	FL	0110037-017-AC	221112	12/04/2017 ACT	1200 megawatt 2-on-1 combined cycle facility, natural gas-fired, with limited ULSD use. GE 7HA turbines	Two 3300 kW emergency generators	ULSD	0		Particulate matter, filterable (FPM)	Clean fuel	0.2	GRAMS PER KWH		BACT-PSD	NSPS	0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Particulate matter, total (TPM)	good combustion practices	0.2	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		0.22	TONS/YR	ROLLING 12 MONTH TOTAL	0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Particulate matter, total < 10 Âµ (TPM10)	good combustion practices	0.2	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		0.22	TONS/YR	ROLLING 12 MONTH TOTAL	0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	good combustion practices	0.2	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		0.22	TONS/YR	ROLLING 12 MONTH TOTAL	0		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Particulate matter, total (TPM)	good combustion practices	0.2	G/KW-H	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD		0.02	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	0		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Particulate matter, total < 10 Âµ (TPM10)	good combustion practices	0.2	G/KW-H	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	SIP	0.02	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	0		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	good combustion practices	0.2	G/KW-H	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	SIP	0.02	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	0		
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	17040013	221112	12/31/2018 ACT	The proposed facility is designed to generate baseload power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would only burn natural gas. Other units include an auxiliary boiler, fuel heater, emergency engines, natural gas piping and components, circuit breakers and roadways	Emergency Engine	Ultra-Low Sulfur Diesel	1500	kW	Particulate matter, total (TPM)		0.2	G/KW-HR		BACT-PSD	NSPS	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency generator EU-6006	Diesel	2800	HP	Particulate matter, total (TPM)	Tier II diesel engine	0.2	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency generator EU-6006	Diesel	2800	HP	Particulate matter, total < 10 Âµ (TPM10)	Tier II diesel engine	0.2	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency generator EU-6006	Diesel	2800	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Tier II diesel engine	0.2	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency fire pump EU-6008	Diesel	750	HP	Particulate matter, total < 10 Âµ (TPM10)	Engine that complies with Table 4 to Subpart IIII of Part 60	0.2	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency fire pump EU-6008	Diesel	750	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Engine that complies with Table 4 to Subpart IIII of Part 60	0.2	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency fire pump EU-6008	Diesel	750	HP	Particulate matter, total (TPM)	Engine that complies with Table 4 to Subpart IIII of Part 60	0.2	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	06/04/2015 ACT	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Emergency Generator Engines	Diesel	2922	hp (each)	Particulate matter, total < 10 Âµ (TPM10)	Complying with 40 CFR 60 Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	06/04/2015 ACT	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Emergency Generator Engines	Diesel	2922	hp (each)	Particulate matter, total < 2.5 Âµ (TPM2.5)	Complying with 40 CFR 60 Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Large Emergency Engines (>50kW)	Diesel Fuel	5364	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion and operating practices.	0.2	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Large Emergency Engines (>50kW)	Diesel Fuel	5364	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion and operating practices.	0.2	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUEMENGINE (Diesel fuel emergency engine)	Diesel Fuel	22.68	MMBTU/H	Particulate matter, filterable (FPM)	Good combustion practices and meeting NSPS Subpart IIII requirements.	0.2	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (North Plant): Emergency Engine	Diesel	1341	HP	Particulate matter, filterable (FPM)	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.2	G/KW-H	HOURLY	BACT-PSD	NSPS	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (South Plant): Emergency Engine	Diesel	1341	HP	Particulate matter, filterable (FPM)	Diesel particulate filter, good combustion practices and meeting NSPS IIII requirements.	0.2	G/KW-H	HOURLY	BACT-PSD	NSPS	0			0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	19-18	221112	07/16/2018 ACT	Natural gas combined-cycle power plant	EUEMENGINE: Emergency engine	Diesel	2	MW	Particulate matter, filterable (FPM)	State of the art combustion design	0.2	G/KW-H	HOURLY	BACT-PSD	NSPS	0			0		
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16B	221112	11/26/2019 ACT	Natural gas combined cycle power plant	EUEMENGINE (diesel fuel emergency engine)	diesel fuel	22.68	MMBTU/H	Particulate matter, filterable (FPM)	Good Combustion Practices and meeting NSPS Subpart IIII requirements	0.2	G/KW-H	HOURLY	BACT-PSD	NSPS	0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	P0110840	221112	06/18/2013 ACT	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency generator	diesel	2250	KW	Particulate matter, total < 10 Âµ (TPM10)	Purchased certified to the standards in NSPS Subpart IIII	0.99	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	0.25	T/YR	PER ROLLING 12-MONTHS	0		SEE NOTES
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	P0113762	221112	11/05/2013 ACT	Natural gas fired combined cycle gas turbine electric generating station of nominal capacity of 742 MW	Emergency generator (P003)	diesel	1112	KW	Particulate matter, total < 10 Âµ (TPM10)	Purchased certified to the standards in NSPS Subpart IIII	0.49	LB/H		BACT-PSD	NSPS	0.12	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	P0113762	221112	11/05/2013 ACT	Natural gas fired combined cycle gas turbine electric generating station of nominal capacity of 742 MW	Emergency generator (P003)	diesel	1112	KW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Purchased certified to the standards in NSPS Subpart IIII	0.49	LB/H		BACT-PSD	NSPS	0.12	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	P0117655	221112	08/25/2015 ACT	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2346	HP	Particulate matter, total < 10 Âµ (TPM10)	State-of-the-art combustion design	0.77	LB/H		BACT-PSD	NSPS	0.19	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	P0117655	221112	08/25/2015 ACT	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2346	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	State-of-the-art combustion design	0.77	LB/H		BACT-PSD	NSPS	0.19	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	P0119495	221112	09/23/2016 ACT	1150 MW combined-cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2947	HP	Particulate matter, total < 10 Âµ (TPM10)	State-of-the-art combustion design	0.97	LB/H		BACT-PSD	NSPS	0.24	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	P0119495	221112	09/23/2016 ACT	1150 MW combined-cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2947	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	State-of-the-art combustion design	0.97	LB/H		BACT-PSD	NSPS	0.24	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	P0122331	221112	09/07/2017 ACT	940 MW combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Particulate matter, total < 10 Âµ (TPM10)	Ultra low sulfur diesel fuel	0.5	LB/H		BACT-PSD	NSPS	0.13	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	P0122331	221112	09/07/2017 ACT	940 MW combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Ultra low sulfur diesel fuel	0.5	LB/H		BACT-PSD	NSPS	0.13	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Particulate matter, filterable (FPM)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.2	G/KW-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators No. 1 & No. 2	Diesel	1341	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of a certified engine, low sulfur diesel, and limiting non-emergency use to no more than 100 hours per year	0.44	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.02	TPY	ANNUAL MAXIMUM	0.15	G/BHP-HR	
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NESHAP , NSPS	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	PSD-LA-767	221112	09/26/2013 ACT		2000 KW Diesel Fired Emergency Generator Engine	Diesel	20.4	MMBTU/hr	Particulate matter, filterable < 10 Âµ (FPM10)	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	1.06	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0.04	T/YR	ANNUAL MAXIMUM	0		
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	PSD-LA-767	221112	09/26/2013 ACT		2000 KW Diesel Fired Emergency Generator Engine	Diesel	20.4	MMBTU/hr	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	1.06	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0.04	T/YR	ANNUAL MAXIMUM	0		
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT03	211111	01/23/2015 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY.	Emergency Camp Generators	Ultra Low Sulfur Diesel	2695	hp	Particulate matter, filterable < 10 Âµ (FPM10)		0.15	GRAMS/HP-H		BACT-PSD		0			0		
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT03	211111	01/23/2015 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY.	Emergency Camp Generators	Ultra Low Sulfur Diesel	2695	hp	Particulate matter, filterable < 2.5 Âµ (FPM2.5)		0.15	GRAMS/HP-H		BACT-PSD		0			0		
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	CA	SE 09-01	221112	10/18/2011 ACT	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	EMERGENCY IC ENGINE	DIESEL	2683	HP	Particulate matter, total (TPM)	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H		BACT-PSD		0.15	G/HP-H		0		
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	CA	SE 09-01	221112	10/18/2011 ACT	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	EMERGENCY IC ENGINE	DIESEL	2683	HP	Particulate matter, total < 10 Âµ (TPM10)	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H		BACT-PSD		0.15	G/HP-H		0		
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	CA	SE 09-01	221112	10/18/2011 ACT	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	EMERGENCY IC ENGINE	DIESEL	2683	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	USE ULTRA LOW SULFUR FUEL	0.2	G/KW-H		BACT-PSD		0.15	G/HP-H		0		
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	PSD-FL-416, 0550063-001-AC	221119	09/23/2011 ACT	THIS PROJECT INVOLVES THE CONSTRUCTION OF A SUGARCANE AND SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY WITH A MAXIMUM ANNUAL ETHANOL (C2H5OH) PRODUCTION RATE OF 36 MILLION GALLONS PER YEAR (MGPY). THE CANE (I.E. THE SUGARCANE AND SORGHUM) WILL BE GROWN ON NEARBY FARMLAND. THE JUICE WILL BE SQUEEZED FROM THE FEEDSTOCK	600 HP Emergency Equipment	Ultra-Low Sulfur Oil	0		Particulate matter, total (TPM)	See Pollutant Notes.	0.15	G/HP-H		BACT-PSD	NSPS	0			0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENEGRY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Particulate matter, filterable (FPM)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	G/HP-H		BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENEGRY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Particulate matter, filterable < 10 Âµ (FPM10)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENEGRY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENEGRY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Particulate matter, filterable (FPM)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEALRY	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENEGRY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Particulate matter, filterable < 10 Âµ (FPM10)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEALRY	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENEGRY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	0.15	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES	0.15	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES	0.15	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES	0.15	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES	0.15	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES	0.15	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES	0.15	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	DIESEL-FIRED EMERGENCY GENERATOR	NO. 2 FUEL OIL	4690	B-HP	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	DIESEL-FIRED EMERGENCY GENERATOR	NO. 2 FUEL OIL	4690	B-HP	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Particulate matter, filterable (FPM)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES	0.15	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	EMERGENCY GENERATORS (EU014A AND EU-014B)	DISTILLATE OIL	3600	HP EACH	Particulate matter, total (TPM)	GOOD COMBUSTION PRACTICES	0.15	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		500	H/YR EACH		0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	EMERGENCY GENERATORS (EU014A AND EU-014B)	DISTILLATE OIL	3600	HP EACH	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES	0.15	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		500	H/YR EACH		0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	EMERGENCY GENERATORS (EU014A AND EU-014B)	DISTILLATE OIL	3600	HP EACH	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES	0.15	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		500	H/YR EACH		0		
KS-0040	JOHNS MANVILLE AT MCPHERSON	JOHNS MANVILLE	KS	CSD00081 V1.0	327993	12/03/2019 ACT	Fiberglass Mineral Wool Insulation Manufacturing.	Emergency Diesel Engines		0		Particulate matter, filterable (FPM)	Emergency Diesel Engine and Fire Pump Subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.	0.2	GR/KWH		BACT-PSD	NSPS	0.15	G/BHP-H		0		
KS-0040	JOHNS MANVILLE AT MCPHERSON	JOHNS MANVILLE	KS	CSD00081 V1.0	327993	12/03/2019 ACT	Fiberglass Mineral Wool Insulation Manufacturing.	Emergency Diesel Engines		0		Particulate matter, filterable < 10 Âµ (FPM10)	One diesel engine and fire pump subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.	0.2	G/KWH		BACT-PSD	NSPS	0.15	G/BHP-H		0		
KS-0040	JOHNS MANVILLE AT MCPHERSON	JOHNS MANVILLE	KS	CSD00081 V1.0	327993	12/03/2019 ACT	Fiberglass Mineral Wool Insulation Manufacturing.	Emergency Diesel Engines		0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	One diesel fuel emergency engine and one fire pump subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.	0.2	GR/KWH		BACT-PSD	NSPS	0.15	G/BHP-H		0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NESHAP , NSPS	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Particulate matter, filterable (FPM)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Particulate matter, total < 10 Âµ (TPM10)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD		0			0		
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	2827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	0.15	G/HP-H	ANNUAL AVERAGE	BACT-PSD	OPERATING PERMIT	0			0.15	G/HP-H	ANNUAL AVERAGE
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	2827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Particulate matter, total < 10 Âµ (TPM10)	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	0.15	G/HP-H	ANNUAL AVERAGE	BACT-PSD	OPERATING PERMIT	0			0.15	G/HP-H	ANNUAL AVERAGE
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	CPCN CASE NO. 9327	221119	04/08/2014 ACT	1000 MW NATURAL COMBINED CYCLE NATURAL GAS FIRED POWER PLANTFACILITY-WIDE PM10 EMISSION LIMIT = 278 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT = 272 TONS/YR FACILITY-WIDE SAM EMISSION LIMIT = 96 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 3,498,026 TONS/YR	EMERGENCY GENERATOR 1	ULTRA LOW SULFU DIESEL	2250	KW	Particulate matter, filterable (FPM)	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.15	G/HP-H		BACT-PSD	NSPS	0.2	G/KW-H		0		
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	CPCN CASE NO. 9327	221119	04/08/2014 ACT	1000 MW NATURAL COMBINED CYCLE NATURAL GAS FIRED POWER PLANTFACILITY-WIDE PM10 EMISSION LIMIT = 278 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT = 272 TONS/YR FACILITY-WIDE SAM EMISSION LIMIT = 96 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 3,498,026 TONS/YR	EMERGENCY GENERATOR 1	ULTRA LOW SULFU DIESEL	2250	KW	Particulate matter, total < 10 Âµ (TPM10)	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.15	G/HP-H		BACT-PSD	NSPS	0.23	G/KW-H		0		
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	CPCN CASE NO. 9327	221119	04/08/2014 ACT	1000 MW NATURAL COMBINED CYCLE NATURAL GAS FIRED POWER PLANTFACILITY-WIDE PM10 EMISSION LIMIT = 278 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT = 272 TONS/YR FACILITY-WIDE SAM EMISSION LIMIT = 96 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 3,498,026 TONS/YR	EMERGENCY GENERATOR 1	ULTRA LOW SULFU DIESEL	2250	KW	Particulate matter, total < 2.5 Âµ (TPM2.5)	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.15	G/HP-H		BACT-PSD	NSPS	0.23	G/KW-H		0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1550	HP	Particulate matter, filterable (FPM)	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.15	G/HP-H		BACT-PSD		0.2	G/KW-H		0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	Emergency generator	Diesel	4000	HP	Particulate matter, filterable (FPM)		0.15	G/HP-H	TEST PROTOCOL; BACT/SIP/NSPS	BACT-PSD	NSPS , SIP	0			0		
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	51-13	221112	11/01/2013 ACT	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Facility-wide limit for (2) 1,000kW diesel-fueled emergency reciprocating internal combustion	Diesel	1000	kW	Particulate matter, filterable (FPM)	Good combustion practices.	0.15	G/B-HP-H	TEST PROTOCOL; EACH UNIT	BACT-PSD	NSPS	0			0		
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	51-13	221112	11/01/2013 ACT	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Facility-wide limit for (2) 1,000kW diesel-fueled emergency reciprocating internal combustion	Diesel	1000	kW	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	0.15	G/B-HP-H	TEST PROTOCOL; EACH UNIT.	BACT-PSD	SIP	0			0		
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	51-13	221112	11/01/2013 ACT	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	Facility-wide limit for (2) 1,000kW diesel-fueled emergency reciprocating internal combustion	Diesel	1000	kW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	0.15	G/B-HP-H	TEST PROTOCOL; EACH UNIT.	BACT-PSD	SIP	0			0		
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	P0121049	221112	09/27/2017 ACT	Combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Particulate matter, total < 10 Âµ (TPM10)	Ultra low sulfur diesel fuel	0.5	LB/H		BACT-PSD	NSPS	0.13	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/B-HP-H	SEE NOTES
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	P0121049	221112	09/27/2017 ACT	Combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Ultra low sulfur diesel fuel	0.5	LB/H		BACT-PSD	NSPS	0.13	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/B-HP-H	SEE NOTES
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Particulate matter, total (TPM)	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturer's operating manual.	0.73	LB/H		BACT-PSD	NSPS	0.037	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Particulate matter, total < 10 Âµ (TPM10)	certified to the meets the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturerâ€™s operating manual.	0.73	LB/H		BACT-PSD	NSPS	0.037	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	certified to the meets the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturerâ€™s operating manual.	0.73	LB/H		BACT-PSD	NSPS	0.037	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Particulate matter, total (TPM)	Good combustion design	0.73	LB/H		BACT-PSD	NSPS	0.037	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion design	0.73	LB/H		BACT-PSD	NSPS	0.037	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion design	0.73	LB/H		BACT-PSD	NSPS	0.037	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Particulate matter, total (TPM)	Good combustion design	0.23	LB/H		BACT-PSD	NSPS	0.012	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion design	0.23	LB/H		BACT-PSD	NSPS	0.012	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion design	0.23	LB/H		BACT-PSD	NSPS	0.012	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0377	HARRISON POWER	HARRISON POWER	OH	P0122266	221112	04/19/2018 ACT	1000 MW natural gas-fired combined cycle combustion turbine plant	Emergency Diesel Generator (P003)	Diesel fuel	1860	HP	Particulate matter, total (TPM)	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	0.62	LB/H		BACT-PSD	NSPS	0.031	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0377	HARRISON POWER	HARRISON POWER	OH	P0122266	221112	04/19/2018 ACT	1000 MW natural gas-fired combined cycle combustion turbine plant	Emergency Diesel Generator (P003)	Diesel fuel	1860	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	0.62	LB/H		BACT-PSD	NSPS	0.031	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0377	HARRISON POWER	HARRISON POWER	OH	P0122266	221112	04/19/2018 ACT	1000 MW natural gas-fired combined cycle combustion turbine plant	Emergency Diesel Generator (P003)	Diesel fuel	1860	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	0.62	LB/H		BACT-PSD	NSPS	0.031	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Particulate matter, total (TPM)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	1.1	LB/H		BACT-PSD	NSPS	0.055	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Particulate matter, total < 10 Âµ (TPM10)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	1.1	LB/H		BACT-PSD	NSPS	0.055	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Particulate matter, total (TPM)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	0.44	LB/H		BACT-PSD	NSPS	0.022	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Particulate matter, total < 10 Âµ (TPM10)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	0.44	LB/H		BACT-PSD	NSPS	0.022	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	0.44	LB/H		BACT-PSD	NSPS	0.022	T/YR	PER ROLLING 12 MONTH PERIOD	0.15	G/BHP-H	SEE NOTES
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	11-00536A	221112	09/02/2016 ACT	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric	Emergency Generator Engines	ULSD	0		Particulate matter, total (TPM)		0.15	G/BHP-HR		BACT-PSD	NSPS	0			0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	11-00536A	221112	09/02/2016 ACT	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric	Emergency Fire Pump Engine	ULSD	0		Particulate matter, total (TPM)		0.15	G/BHP-HR		BACT-PSD	NSPS	0			0		
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Emergency Diesel GEN	Ultra Low Sulfur Diesel	500	H/YR	Particulate matter, filterable (FPM)	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	G/HP H		BACT-PSD	NSPS , SIP	0			0		
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Emergency Diesel GEN	Ultra Low Sulfur Diesel	500	H/YR	Particulate matter, total < 10 Âµ (TPM10)	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	G/HP H		BACT-PSD	NSPS , SIP	0			0		
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Emergency Diesel GEN	Ultra Low Sulfur Diesel	500	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	G/HP H		BACT-PSD	NSPS , SIP	0			0		
*VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	52610-1	221112	06/24/2019 ACT	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/hr natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Emegency Fire Water Pump	Ultra Low Sulfur Diesel	500	HR/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	G/HP-HR		BACT-PSD	NSPS , SIP	0			0		
*VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	52610-1	221112	06/24/2019 ACT	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/hr natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Emegency Fire Water Pump	Ultra Low Sulfur Diesel	500	HR/YR	Particulate matter, total < 10 Âµ (TPM10)	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	G/HP-HR		BACT-PSD	NSPS , SIP	0			0		
*VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	52610-1	221112	06/24/2019 ACT	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/hr natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Emegency Fire Water Pump	Ultra Low Sulfur Diesel	500	HR/YR	Particulate matter, filterable (FPM)	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.15	G/HP-HR		BACT-PSD	SIP , NSPS	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Emergency Generator	Diesel	2015.7	HP	Particulate matter, filterable < 2.5 Âµ (FPM2.5)		0			BACT-PSD	NSPS	0			0.15	G/HP-HR	
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	Diesel	2922	HP	Particulate matter, total < 10 Âµ (TPM10)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	Diesel	2922	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	Diesel	2922	HP	Particulate matter, filterable (FPM)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan.	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP , MACT	0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Tunnel Furnace Emergency Generator (EP 08-06)	Diesel	2937	HP	Particulate matter, total < 10 Âµ (TPM10)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Tunnel Furnace Emergency Generator (EP 08-06)	Diesel	2937	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Tunnel Furnace Emergency Generator (EP 08-06)	Diesel	2937	HP	Particulate matter, filterable (FPM)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Caster B Emergency Generator (EP 08-07)	Diesel	2937	HP	Particulate matter, total < 10 Âµ (TPM10)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Caster B Emergency Generator (EP 08-07)	Diesel	2937	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Caster B Emergency Generator (EP 08-07)	Diesel	2937	HP	Particulate matter, filterable (FPM)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Air Separation Unit Emergency Generator (EP 08-08)	Diesel	700	HP	Particulate matter, total < 10 Âµ (TPM10)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Air Separation Unit Emergency Generator (EP 08-08)	Diesel	700	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Air Separation Unit Emergency Generator (EP 08-08)	Diesel	700	HP	Particulate matter, filterable (FPM)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	Particulate matter, total < 10 Âµ (TPM10)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD		0			0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	Particulate matter, filterable (FPM)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0.15	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	horsepower	Particulate matter, total < 10 Âµ (TPM10)	Compliance with NSPS Subpart IIII	0.15	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	horsepower	Particulate matter, total < 2.5 Âµ (TPM2.5)	Compliance with NSPS IIII	0.15	LB/HR		BACT-PSD	OPERATING PERMIT , NSPS	0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	Diesel	1474	horsepower	Particulate matter, total < 10 Âµ (TPM10)	Compliance with NSPS Subpart IIII	0.08	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	Diesel	1474	horsepower	Particulate matter, total < 2.5 Âµ (TPM2.5)	Compliance with NSPS Subpart IIII	0.08	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	PSD-LA-804	221112	08/31/2016 ACT	The St. Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.	SCPS Emergency Diesel Generator 1	Diesel	2584	HP	Particulate matter, filterable < 10 Âµ (FPM10)	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	0.86	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.21	T/YR	ANNUAL MAXIMUM	0		
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	PSD-LA-804	221112	08/31/2016 ACT	The St. Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.	SCPS Emergency Diesel Generator 1	Diesel	2584	HP	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	0.86	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0.21	T/YR	ANNUAL MAXIMUM	0		
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 1	Diesel	5364	HP	Particulate matter, total < 10 Âµ (TPM10)	Proper design and operation; use of ultra-low sulfur diesel	1.76	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.09	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 1	Diesel	5364	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Proper burner design and operation	1.76	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.09	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 2	Diesel	5364	HP	Particulate matter, total < 10 Âµ (TPM10)	Proper design and operation; use of ultra-low sulfur diesel	1.76	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.09	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 2	Diesel	5364	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Proper design and operation; use of ultra-low sulfur diesel	1.76	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.09	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 1	Diesel	751	HP	Particulate matter, total < 10 Âµ (TPM10)	Proper design and operation; use of ultra-low sulfur diesel	0.25	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.01	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 1	Diesel	751	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Proper design and operation; use of ultra-low sulfur diesel	0.25	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.01	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 2	Diesel	751	HP	Particulate matter, total < 10 Âµ (TPM10)	Proper design and operation; use of ultra-low sulfur diesel	0.25	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.01	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 2	Diesel	751	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Proper design and operation; use of ultra-low sulfur diesel	0.25	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.01	T/YR	ANNUAL MAXIMUM	0.15	G/BHP-H	
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	PSC CASE NO. 9136	221119	07/01/2014 ACT	310 MEGAWATT SIMPLE CYCLE NATURAL GAS FIRED POWER PLANT PERRYMAN G PROJECT-WIDE EMISSION LIMITS: PM10 = 43.0 TONS/YR PM2.5 = 43.0 TONS/YR NOX = 58.5 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1300	HP	Particulate matter, total < 10 Âµ (TPM10)	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	0.17	G/HP-H	CONDENSIBLE + FILTERABLE	BACT-PSD	NSPS	0.15	G/HP-H	FILTERABLE	0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1550	HP	Particulate matter, total < 10 Âµ (TPM10)	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.17	G/HP-H		BACT-PSD		0.23	G/KW-H		0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1550	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMITS	0.17	G/HP-H		BACT-PSD		0.23	G/KW-H		0		
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	P0123395	331111	02/09/2018 ACT	Hot briquetted iron production	Emergency diesel-fired generator (P007)	Diesel fuel	2682	HP	Particulate matter, total < 10 Âµ (TPM10)	Comply with NSPS 40 CFR 60 Subpart IIII	1.01	LB/H		BACT-PSD	NSPS	0.25	T/YR	PER ROLLING 12 MONTH PERIOD	0.17	G/BHP-H	SEE NOTES
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	P0123395	331111	02/09/2018 ACT	Hot briquetted iron production	Emergency diesel-fired generator (P007)	Diesel fuel	2682	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Comply with NSPS 40 CFR 60 Subpart IIII	1.01	LB/H		BACT-PSD	NSPS	0.25	T/YR	PER ROLLING 12 MONTH PERIOD	0.17	G/BHP-H	SEE NOTES
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Black Start and Emergency Internal Cumbustion Engines	Diesel	1500	kWe	Particulate matter, total (TPM)	Clean Fuel and Good Combustion Practices	0.25	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Black Start and Emergency Internal Cumbustion Engines	Diesel	1500	kWe	Particulate matter, total < 10 Âµ (TPM10)	Clean Fuel and Good Combustion Practices	0.25	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Black Start and Emergency Internal Cumbustion Engines	Diesel	1500	kWe	Particulate matter, total < 2.5 Âµ (TPM2.5)	Clean Fuel and Good Combustion Practices	0.25	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
FL-0346	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	0110037-011-AC	221112	04/22/2014 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Emergency fire pump engine (300 HP)	USLD	29	MMBTU/H	Particulate matter, total (TPM)	Good combustion practice	0.2	GRAM PER HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
OK-0156	NORTHSTAR AGRI IND ENID	NORTHSTAR AGRI INDUSTRIES	OK	2013-0109-C PSD	311223	07/31/2013 ACT	The new Northstar Agri Industries â€" Enid facility will be designed to convert 2,500 TPD of seeds into crude oil and RBD oil. The facility consists of several processing steps to prepare seed and remove up to 100 million gallons per year of crude oil and RBD oil.	Fire Pump Engine	Diesel	550	hp	Particulate matter, total < 10 Âµ (TPM10)		0.2	GM/HP-HR		BACT-PSD	NSPS	0			0		
OK-0156	NORTHSTAR AGRI IND ENID	NORTHSTAR AGRI INDUSTRIES	OK	2013-0109-C PSD	311223	07/31/2013 ACT	The new Northstar Agri Industries â€" Enid facility will be designed to convert 2,500 TPD of seeds into crude oil and RBD oil. The facility consists of several processing steps to prepare seed and remove up to 100 million gallons per year of crude oil and RBD oil.	Fire Pump Engine	Diesel	550	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.2	GM/HP-HR		BACT-PSD	NSPS	0			0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Fire Pump Engine	diesel	0		Particulate matter, total (TPM)		0.2	G/HP-HR		BACT-PSD	NSPS	0.006	TPY	12-MONTH ROLLING BASIS	0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Fire Pump Engine	diesel	0		Particulate matter, total < 10 Âµ (TPM10)		0.2	G/HP-HR		BACT-PSD	NSPS	0.006	TPY	12-MONTH ROLLING BASIS	0		
*PA-0313	FIRST QUALITY TISSUE LOCK HAVEN PLT	FIRST QUALITY TISSUE, LLC	PA	18-00030C	322291	07/27/2017 ACT	This plan approval is for the construction of one (1) tissue paper machine and tissue machine comprised of a wet-end section, a wet-end dryer section, a dry-end dryer section and a dry-end section. The wet-end dryer shall incorporate a through-airdryer equipped with a 105 million Btu per hour, natural gas/propane-fired in-line, low NOx, duct burner. The dry-end dryer shall	Emergency Generator	Diesel	2500	bhp	Particulate matter, total (TPM)		0.2	G	HP-HR			0.21	TON	12-CONSECUTIVE MONTH PERIOD	0		
WV-0027	INWOOD	KNAUF INSULATION INC.	WV	R14-0015M	327993	09/15/2017 ACT	Insulation Manufacturing Facility	Emergency Generator - ESDG14	ULSD	900	bhp	Particulate matter, total < 10 Âµ (TPM10)	ULSD	0.2	G/HP-HR		BACT-PSD	NSPS	0			0		
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Emergency generator (P002)	Diesel fuel	1100	KW	Particulate matter, total (TPM)	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	0.77	LB/H		BACT-PSD	NSPS	0.19	T/YR	PER ROLLING 12 MONTH PERIOD	0.236	G/B-HP-H	
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Emergency generator (P002)	Diesel fuel	1100	KW	Particulate matter, total < 10 Âµ (TPM10)	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	0.77	LB/H		BACT-PSD	NSPS	0.19	T/YR	PER ROLLING 12 MONTH PERIOD	0.236	G/B-HP-H	
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Emergency generator (P002)	Diesel fuel	1100	KW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	0.77	LB/H		BACT-PSD	NSPS	0.19	T/YR	PER ROLLING 12 MONTH PERIOD	0.236	G/B-HP-H	

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 2,800 MW combined-cycle electric power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	DIESEL FUEL	0		Particulate matter, total < 10 Âµ (TPM10)	Ultra Low Sulfur Diesel/Fuel (15 ppm max)	0.4	G/KW	PER HR	N/A		1	T/YR	12 MO ROLLING TOTAL	0		
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 2,800 MW combined-cycle electric power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	DIESEL FUEL	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Ultra Low Sulfur Diesel/Fuel (15 ppm max)	0.4	G/KR	PER HR	N/A		0.7	T/YR	12 MO ROLLING TOTAL	0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Firewater Pumps	Diesel Fuel	634	kW	Particulate matter, total < 10 Âµ (TPM10)	Good combustion and operating practices.	0.3	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Firewater Pumps	Diesel Fuel	634	kW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion and operating practices.	0.3	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033-X014 - X020	331111	07/22/2014 ACT	STEEL MILL ADDING 2ND BAGHOUSE TO EAF, AUSTENITIZING FURNACE, TEMPERING FURNACE, VACUUM DEGASSER, PLASMA TORCHES, AND EMERGENCY GENERATORS	DIESEL FIRED EMERGENCY GENERATOR	DIESEL	800	HP	Particulate matter, filterable (FPM)		0.0007	LB/HP-H		BACT-PSD	NSPS , MACT	0			0		
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033-X014 - X020	331111	07/22/2014 ACT	STEEL MILL ADDING 2ND BAGHOUSE TO EAF, AUSTENITIZING FURNACE, TEMPERING FURNACE, VACUUM DEGASSER, PLASMA TORCHES, AND EMERGENCY GENERATORS	DIESEL FIRED EMERGENCY GENERATOR	DIESEL	800	HP	Particulate matter, filterable (FPM)		0.0007	LB/HP-H		BACT-PSD	NSPS , MACT	0			0		
*WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	SIO INTERNATIONAL	WI	18-JJW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Particulate matter, total (TPM)	Good Combustion Practices and The Use of Ultra-low Sulfur Fuel	17	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	DIESEL-FIRED EMERGENCY GENERATOR	NO. 2 FUEL OIL	4690	B-HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	GOOD COMBUSTION PRACTICES	0.15	LB/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Visible Emissions (VE)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	20	%		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATORS	DIESEL	1500	KW	Visible Emissions (VE)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	20	%		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Visible Emissions (VE)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	20	%		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Visible Emissions (VE)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	20	%		BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Engine	Diesel	0		Particulate matter, total (TPM)	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	0.03	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Engine	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Engine	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Fire Pump Engine	Diesel	0		Particulate matter, total (TPM)	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	0.002	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Fire Pump Engine	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Fire Pump Engine	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	Use of certified EPA Tier 1 engines and good combustion practices based on the current manufacturerâ€™s specifications for this engine.	0.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Diesel Engine - Development Driller 1	Diesel	2229	hp	Particulate matter, total (TPM)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	0.03	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - Development Driller 1	Diesel	2229	hp	Particulate matter, total < 10 Âµ (TPM10)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	0.03	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - Development Driller 1	Diesel	2229	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	0.03	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - C.R. Luigs	diesel	2064	hp	Particulate matter, total (TPM)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	0.04	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - C.R. Luigs	diesel	2064	hp	Particulate matter, total < 10 Âµ (TPM10)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	0.02	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - C.R. Luigs	diesel	2064	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	0.02	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Emergency Diesel Engine	Diesel	3300	hp	Particulate matter, total (TPM)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Visible Emissions (VE)	good combustion practices	5	% OPACITY	6 MINUTE AVERAGE	BACT-PSD		0			0		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Visible Emissions (VE)	good combustion practices	5	%	SIX (6) MINUTE AVERAGE	BACT-PSD		0			0		
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	16060032	221112	07/30/2018 ACT	The proposed facility is designed to generate dispatch power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would burn natural gas and ultra-low sulfur diesel (ULSD) as a backup fuel. Other units include an auxiliary boiler, fuel heater, engines, natural gas piping and	Emergency Engines	Ultra-low sulfur diesel	0		Particulate matter, total (TPM)		0			BACT-PSD	NSPS	0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Particulate matter, total < 10 Âµ (TPM10)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR		BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Particulate matter, total < 2.5 Âµ (TPM2.5)	USE OF LOW-S DIESEL	15	PPM SULFUR		BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Particulate matter, filterable (FPM)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR		BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Particulate matter, filterable (FPM)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR		BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Particulate matter, total < 10 Âµ (TPM10)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR		BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Particulate matter, total < 2.5 Âµ (TPM2.5)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR		BACT-PSD		0			0		
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		2682	HP	Particulate matter, total < 10 Âµ (TPM10)	Comply with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0.88	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.04	TPY	ANNUAL MAXIMUM	0		
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		2682	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Comply with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0.88	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.04	TPY	ANNUAL MAXIMUM	0		
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators No. 1 & No. 2	Diesel	1341	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of a certified engine, low sulfur diesel, and limiting non-emergency use to no more than 100 hours per year	0.44	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.02	TPY	ANNUAL MAXIMUM	0.15	G/BHP-HR	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325211	05/23/2014 ACT	The Low Density Polyethylene (LDPE) Unit will produce LDPE by the high pressure polymerization of ethylene.	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105,	Diesel	2682	HP	Particulate matter, total < 10 Âµ (TPM10)	Comply with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel	0.88	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.04	TPY	ANNUAL MAXIMUM	0		
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325211	05/23/2014 ACT	The Low Density Polyethylene (LDPE) Unit will produce LDPE by the high pressure polymerization of ethylene.	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105,	Diesel	2682	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Comply with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel	0.88	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT , NSPS	0.04	TPY	ANNUAL MAXIMUM	0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Diesel Engines (Emergency)	Diesel	4023	hp	Particulate matter, total < 10 Âµ (TPM10)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Diesel Engines (Emergency)	Diesel	4023	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	emergency generator engines (6 units)	diesel	3353	hp	Particulate matter, total < 10 Âµ (TPM10)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	emergency generator engines (6 units)	diesel	3353	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Emergency Generator Engines (4 units)	Diesel	0		Particulate matter, total < 10 Âµ (TPM10)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Emergency Generator Engines (4 units)	Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Firewater pump Engines (4 units)	diesel	896	hp (each)	Particulate matter, total < 10 Âµ (TPM10)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Firewater pump Engines (4 units)	diesel	896	hp (each)	Particulate matter, total < 2.5 Âµ (TPM2.5)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 3 Engine	Diesel Fuel	600	hp	Particulate matter, total < 10 Âµ (TPM10)	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 3 Engine	Diesel Fuel	600	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 4 Engine	Diesel Fuel	600	hp	Particulate matter, total < 10 Âµ (TPM10)	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 4 Engine	Diesel Fuel	600	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
*LA-0350	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-744(M2)	331210	03/28/2018 ACT	A steel tube manufacturing facility from scrap metal	emergency generators (3 units) EQT0039, EQT0040, EQT0041		0		Particulate matter, total < 10 Âµ (TPM10)	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
*LA-0350	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-744(M2)	331210	03/28/2018 ACT	A steel tube manufacturing facility from scrap metal	emergency generators (3 units) EQT0039, EQT0040, EQT0041		0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Generator Diesel Engines	Diesel Fuel	550	hp	Particulate matter, total < 10 Âµ (TPM10)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Generator Diesel Engines	Diesel Fuel	550	hp	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and loading operations (Logistics), and associated flare systems.	Emergency Fire Water Pumps	Diesel Fuel	550	hp	Particulate matter, total < 10 Âµ (TPM10)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and loading operations (Logistics), and associated flare systems.	Emergency Fire Water Pumps	Diesel Fuel	550	hp	Particulate matter, total < 2.5 Âµ (TPM2.5)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		
*MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	NE-15-018	611310	06/21/2017 ACT	MIT proposes to construct and operate two new 22 megawatt (MW) combined heat and power (CHP) combustion turbines/heat recovery steam generators and a new cold start engine at its existing Central Utility Plant.	Cold Start Engine	ULSD	19.04	MMBTU/HR	Particulate matter, total < 10 Âµ (TPM10)		0.4	LB/HR		BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	0.06	TONS/C12MP		0		
*MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	NE-15-018	611310	06/21/2017 ACT	MIT proposes to construct and operate two new 22 megawatt (MW) combined heat and power (CHP) combustion turbines/heat recovery steam generators and a new cold start engine at its existing Central Utility Plant.	Cold Start Engine	ULSD	19.04	MMBTU/HR	Particulate matter, total < 2.5 Âµ (TPM2.5)		0.4	LB/HR		BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	0.06	TONS/C12MP		0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	Emergency generator	Diesel	4000	HP	Particulate matter, total < 10 Âµ (TPM10)		1.76	LB/H	TEST PROTOCOL; BACT	BACT-PSD		0			0		
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	MI	317-07	221112	06/29/2011 ACT	Coal-fired power plant.	Emergency generator	Diesel	4000	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)		1.76	LB/H	TEST PROTOCOL; BACT	BACT-PSD		0			0		
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	81-11	221112	11/17/2011 ACT	Utility--Natural gas fired combustion turbine	Diesel fuel-fired combustion engine (RICE)	Diesel	732	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	0.0573	LB/MMBTU	TEST	BACT-PSD	NSPS , NESHAP , OTHER	0			0		
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	81-11	221112	11/17/2011 ACT	Utility--Natural gas fired combustion turbine	Diesel fuel-fired combustion engine (RICE)	Diesel	732	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	0.0573	LB/MMBTU	TEST	BACT-PSD	NSPS , NESHAP , OTHER	0			0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	Diesel	500	H/YR	Particulate matter, filterable (FPM)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS	0.2	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	Diesel	500	H/YR	Particulate matter, total < 10 Âµ (TPM10)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME.	BACT-PSD	SIP	0			0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	Diesel	500	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	0			0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Diesel fire pump engine (EUFIREPUMP in FGRICE)	Diesel	500	H/YR	Particulate matter, filterable (FPM)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS	0.2	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Diesel fire pump engine (EUFIREPUMP in FGRICE)	Diesel	500	H/YR	Particulate matter, total < 10 Âµ (TPM10)	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	0			0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Diesel fire pump engine (EUFIREPUMP in FGRICE)	Diesel	500	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	0			0		
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUEMENGINE (Diesel fuel emergency engine)	Diesel Fuel	22.68	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices.	1.58	LB/H	HOURLY	BACT-PSD	SIP	0			0		
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUEMENGINE (Diesel fuel emergency engine)	Diesel Fuel	22.68	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices.	1.58	LB/H	HOURLY	BACT-PSD	SIP	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	Diesel	500	H/YR	Particulate matter, filterable (FPM)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	NSPS	0.2	G/KW-H	TEST PROTOCOL SHALL SPECIFY	0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	Diesel	500	H/YR	Particulate matter, total < 10 Âµ (TPM10)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	Diesel	500	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	Diesel	500	H/YR	Particulate matter, filterable (FPM)	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	NSPS	0.2	G/KW-H	TEST PROTOCOL SHALL SPECIFY	0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	Diesel	500	H/YR	Particulate matter, total < 10 Âµ (TPM10)	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	Diesel	500	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUFIREPUMP in FGRICE (Diesel fire pump engine)	Diesel	500	H/YR	Particulate matter, filterable (FPM)	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	NSPS	0.2	G/KW-H	TEST PROTOCOL SHALL SPECIFY	0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUFIREPUMP in FGRICE (Diesel fire pump engine)	Diesel	500	H/YR	Particulate matter, total < 10 Âµ (TPM10)	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUFIREPUMP in FGRICE (Diesel fire pump engine)	Diesel	500	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (North Plant): Emergency Engine	Diesel	1341	HP	Particulate matter, total < 10 Âµ (TPM10)	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.54	LB/H	HOURLY	BACT-PSD	NSPS	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (North Plant): Emergency Engine	Diesel	1341	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.52	LB/H	HOURLY	BACT-PSD	NSPS	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (South Plant): Emergency Engine	Diesel	1341	HP	Particulate matter, total < 10 Âµ (TPM10)	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.54	LB/H	HOURLY	BACT-PSD	NSPS	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (South Plant): Emergency Engine	Diesel	1341	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.	0.52	LB/H	HOURLY	BACT-PSD	NSPS	0			0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	19-18	221112	07/16/2018 ACT	Natural gas combined-cycle power plant	EUEMENGINE: Emergency engine	Diesel	2	MW	Particulate matter, total < 10 Âµ (TPM10)	State of the art combustion design	1.18	LB/H	HOURLY	BACT-PSD	NSPS	0			0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	19-18	221112	07/16/2018 ACT	Natural gas combined-cycle power plant	EUEMENGINE: Emergency engine	Diesel	2	MW	Particulate matter, total < 2.5 Âµ (TPM2.5)	State of the art combustion design.	1.18	LB/H	HOURLY	BACT-PSD	NSPS	0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices, burn ultra-low sulfur diesel fuel and be NSPS compliant.	0.69	LB/H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Ultra low-sulfur diesel fuel.	0.69	LB/H	HOURLY	BACT-PSD	SIP	0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices, burn ultra low sulfur diesel fuel, and be NSPS compliant.	2.7	LB/H	HOURLY	BACT-PSD	NSPS , SIP	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Ultra low sulfur diesel fuel.	2.7	LB/H	HOURLY	BACT-PSD	SIP	0			0		
*MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	210-18	221112	08/21/2019 ACT	New power plant	FGEMENGINE	Diesel	1100	KW	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices and ultra low sulfur diesel	7.85	LB/1000 GAL	HOURLY; EACH ENGINE	BACT-PSD		0			0		
*MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	210-18	221112	08/21/2019 ACT	New power plant	FGEMENGINE	Diesel	1100	KW	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices and ultra low sulfur diesel.	7.55	LB/1000 GAL	HOURLY; EACH ENGINE	BACT-PSD		0			0		
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16B	221112	11/26/2019 ACT	Natural gas combined cycle power plant	EUEMENGINE (diesel fuel emergency engine)	diesel fuel	22.68	MMBTU/H	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices	1.58	LB/H	HOURLY	BACT-PSD	SIP	0			0		
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16B	221112	11/26/2019 ACT	Natural gas combined cycle power plant	EUEMENGINE (diesel fuel emergency engine)	diesel fuel	22.68	MMBTU/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	Good combustion practices	1.58	LB/H	HOURLY	BACT-PSD	SIP	0			0		
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	NJ	18940 - BOP110003	221112	07/25/2012 ACT	Woodbridge Energy Center (WEC), proposed at Riverside Drive in Woodbridge Township (Middlesex County), New Jersey, 07095, would be a new, highly efficient, 700 MW combined-cycle power generating facility. WEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,307 MMBtu/hr, that will utilize pipeline natural gas only. Heat recovery steam generators (HRSGs) downstream of the combustion turbines will recover heat from the exhaust gases to generate steam. The HRSGs will be equipped with natural gas-fired duct burners for supplementary firing and will share a single steam turbine generator (STG). Supporting ancillary equipment includes a natural gas fired auxiliary boiler, one small dew point fuel gas heater (fuel gas heater), a mechanical draft cooling tower, an emergency diesel generator and an emergency diesel fire pump.	Emergency Generator	Ultra Low Sulfur distillate Diesel	100	H/YR	Particulate matter, total < 10 Âµ (TPM10)	Use of ULSD oil	0.13	LB/H		OTHER CASE-BY-CASE	NSPS , OPERATING PERMIT	0			0		
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	NJ	18940 - BOP110003	221112	07/25/2012 ACT	Woodbridge Energy Center (WEC), proposed at Riverside Drive in Woodbridge Township (Middlesex County), New Jersey, 07095, would be a new, highly efficient, 700 MW combined-cycle power generating facility. WEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,307 MMBtu/hr, that will utilize pipeline natural gas only. Heat recovery steam generators (HRSGs) downstream of the combustion turbines will recover heat from the exhaust gases to generate steam. The HRSGs will be equipped with natural gas-fired duct burners for supplementary firing and will share a single steam turbine generator (STG). Supporting ancillary equipment includes a natural gas fired auxiliary boiler, one small dew point fuel gas heater (fuel gas heater), a mechanical draft cooling tower, an emergency diesel generator and an emergency diesel fire pump.	Emergency Generator	Ultra Low Sulfur distillate Diesel	100	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	Use of ULSD oil	0.13	LB/H		OTHER CASE-BY-CASE	NSPS , OPERATING PERMIT	0			0		
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	08857/BOP110001	221112	11/01/2012 ACT	Combined Cycle Electric Generating Facility HESS Newark Energy Center (Hess-NEC), proposed at City of Newark (Essex County), New Jersey, would be a new, highly efficient, 655 MW combined-cycle power generating facility. Hess-NEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,320 MMBtu/hr, that will utilize pipeline natural gas only. Heat recovery steam generators (HRSGs) downstream of the combustion turbines will recover heat from the exhaust gases to generate steam. The HRSGs will be equipped with natural gas-fired duct burners for supplementary firing and will share a single steam turbine generator (STG). Supporting ancillary equipment includes a natural gas fired auxiliary boiler, a 12-cell mechanical draft cooling tower, an emergency diesel generator and an emergency diesel fire pump.	Emergency Generator	ULSD	200	H/YR	Particulate matter, filterable (FPM)	use of ULSD, a low sulfur clean fuel	0.59	LB/H		N/A	OPERATING PERMIT	0			0		
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	08857/BOP110001	221112	11/01/2012 ACT	Combined Cycle Electric Generating Facility HESS Newark Energy Center (Hess-NEC), proposed at City of Newark (Essex County), New Jersey, would be a new, highly efficient, 655 MW combined-cycle power generating facility. Hess-NEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,320 MMBtu/hr, that will utilize pipeline natural gas only. Heat recovery steam generators (HRSGs) downstream of the combustion turbines will recover heat from the exhaust gases to generate steam. The HRSGs will be equipped with natural gas-fired duct burners for supplementary firing and will share a single steam turbine generator (STG). Supporting ancillary equipment includes a natural gas fired auxiliary boiler, a 12-cell mechanical draft cooling tower, an emergency diesel generator and an emergency diesel fire pump.	Emergency Generator	ULSD	200	H/YR	Particulate matter, filterable < 10 Âµ (FPM10)		0.66	LB/H		BACT-PSD	OPERATING PERMIT	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	08857/BOP110001	221112	11/01/2012 ACT	Combined Cycle Electric Generating Facility HESS Newark Energy Center (Hess-NEC), proposed at City of Newark (Essex County), New Jersey, would be a new, highly efficient, 655 MW combined-cycle power generating facility. Hess-NEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,320 MMBtu/hr, that will utilize pipeline natural gas only. Heat recovery steam generators (HRSGs) downstream of the combustion turbines will recover heat from the exhaust gases to generate steam. The HRSGs will be equipped with natural gas-fired duct burners for supplementary firing and will share a single steam turbine generator (STG). Supporting ancillary equipment includes a natural gas fired auxiliary boiler, a 12-cell mechanical draft cooling tower, an emergency diesel generator and an emergency diesel fire pump.	Emergency Generator	ULSD	200	H/YR	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	use of ULSD, a low sulfur clean fuel	0			BACT-PSD	OPERATING PERMIT	0			0		
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	18068/BOP150001	221112	03/10/2016 ACT	PSEG Fossil LLC Sewaren Generating Station (Sewaren or Facility) is located at 751 Cliff Road, Sewaren, New Jersey 07077-1439, Middlesex County, New Jersey. This â€œProjectâ€ to be built at Sewaren would be a 1-on-1 (1 combustion turbine and a single steam turbine) combined-cycle electric generating unit including its ancillary equipment. The electric output of the combined-cycle combustion turbine (CCCT) at ISO conditions will be approximately 345 MW and the approximate output of the steam turbine at these conditions and with 100% supplemental heat input will be 240 MW.	Diesel Fired Emergency Generator	ULSD	44	H/YR	Particulate matter, filterable (FPM)	use of ULSD a clean burning fuel, and limited hours of operation	0.26	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	18068/BOP150001	221112	03/10/2016 ACT	PSEG Fossil LLC Sewaren Generating Station (Sewaren or Facility) is located at 751 Cliff Road, Sewaren, New Jersey 07077-1439, Middlesex County, New Jersey. This â€œProjectâ€ to be built at Sewaren would be a 1-on-1 (1 combustion turbine and a single steam turbine) combined-cycle electric generating unit including its ancillary equipment. The electric output of the combined-cycle combustion turbine (CCCT) at ISO conditions will be approximately 345 MW and the approximate output of the steam turbine at these conditions and with 100% supplemental heat input will be 240 MW.	Diesel Fired Emergency Generator	ULSD	44	H/YR	Particulate matter, total < 10 Âµ (TPM10)	use of ULSD a clean burning fuel, and limited hours of operation	0.26	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	18068/BOP150001	221112	03/10/2016 ACT	PSEG Fossil LLC Sewaren Generating Station (Sewaren or Facility) is located at 751 Cliff Road, Sewaren, New Jersey 07077-1439, Middlesex County, New Jersey. This â€œProjectâ€ to be built at Sewaren would be a 1-on-1 (1 combustion turbine and a single steam turbine) combined-cycle electric generating unit including its ancillary equipment. The electric output of the combined-cycle combustion turbine (CCCT) at ISO conditions will be approximately 345 MW and the approximate output of the steam turbine at these conditions and with 100% supplemental heat input will be 240 MW.	Diesel Fired Emergency Generator	ULSD	44	H/YR	Particulate matter, total < 2.5 Âµ (TPM2.5)	use of ULSD a clean burning fuel, and limited hours of operation	0.26	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
NY-0104	CPV VALLEY ENERGY CENTER	CPV VALLEY LLC	NY	3-3356600136/00001	221112	08/01/2013 ACT	CPV Valley Energy Center is a 680 MW combined cycle electric generating facility located in Middletown, NY. The combustion turbines are rated at 2,234 MMBTU/H firing natural gas and 2,145 MMBTU/H firing diesel fuel. The duct burners are rated for 500 MMBTU/H firing natural gas. In addition to the turbines their emission limits for the auxiliary boiler (73.5 MMBTU/H), emergency generator, fire pump, and gas heater.	Fire pump	ultra low sulfur diesel	0		Particulate matter, filterable (FPM)	Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.	0.043	LB/MMBTU	1 H	BACT-PSD		0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	P0110840	221112	06/18/2013 ACT	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency generator	diesel	2250	KW	Visible Emissions (VE)	Purchased certified to the standards in NSPS Subpart IIII	0			N/A	SIP , OPERATING PERMIT	0			20	% OPACITY	AS A 6-MINUTE AV
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	P0113762	221112	11/05/2013 ACT	Natural gas fired combined cycle gas turbine electric generating station of nominal capacity of 742 MW	Emergency generator (P003)	diesel	1112	KW	Visible Emissions (VE)	Purchased certified to the standards in NSPS Subpart IIII	0			N/A	NSPS , SIP	0			0		SEE NOTES
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Emergency generator (P002)	Diesel fuel	1100	KW	Visible Emissions (VE)	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	0			N/A	NSPS , SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	P0117655	221112	08/25/2015 ACT	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2346	HP	Visible Emissions (VE)	State-of-the-art combustion design	0			BACT-PSD	NSPS , SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	P0119495	221112	09/23/2016 ACT	1150 MW combined-cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2947	HP	Visible Emissions (VE)	State-of-the-art combustion design	0			N/A	NSPS , SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Emergency Generator (P009)	Diesel fuel	5000	HP	Visible Emissions (VE)	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	0			N/A	SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	P0122331	221112	09/07/2017 ACT	940 MW combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Visible Emissions (VE)	Ultra low sulfur diesel fuel	0			BACT-PSD	NSPS , SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	P0121049	221112	09/27/2017 ACT	Combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Visible Emissions (VE)	Ultra low sulfur diesel fuel	0			BACT-PSD	NSPS , SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Visible Emissions (VE)	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the manufacturerâ€™s operating manual.	0			BACT-PSD	NSPS	0			0		SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Visible Emissions (VE)	Good combustion design	0			N/A	NSPS	0			0		SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Visible Emissions (VE)	Good combustion design	0			N/A	SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	P0123395	331111	02/09/2018 ACT	Hot briquetted iron production	Emergency diesel-fired generator (P007)	Diesel fuel	2682	HP	Visible Emissions (VE)	Comply with NSPS 40 CFR 60 Subpart IIII	0			N/A	SIP	0			20	%	OPACITY AS A 6 MINUTE AVERAGE. SEE NOTE
OH-0377	HARRISON POWER	HARRISON POWER	OH	P0122266	221112	04/19/2018 ACT	1000 MW natural gas-fired combined cycle combustion turbine plant	Emergency Diesel Generator (P003)	Diesel fuel	1860	HP	Visible Emissions (VE)	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	0			BACT-PSD	NSPS	0			0		SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Visible Emissions (VE)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	0			BACT-PSD	NSPS	0			0		SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Visible Emissions (VE)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	0			BACT-PSD	NSPS	0			0		SEE NOTES

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	P0125024	331111	02/06/2019 ACT	Merchant Pig Iron Production	Emergency Generators (P005 and P006)	Diesel fuel	3131	HP	Visible Emissions (VE)	Tier IV engine Good combustion practices	0			N/A	NSPS , SIP	0			0		SEE NOTES
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	2008-302-C(M-1)PSD	221112	07/02/2013 ACT	WFEC operates the Mooreland Generating Station to generate wholesale electricity which is transmitted over WFEC's system. The facility was originally constructed in 1963. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma and part of New Mexico. The Mooreland Generating Station currently consists of three high-pressure boilers that burn locally-produced natural gas. The three high-pressure boilers used to generate electricity and the auxiliary boiler used to heat the facility were constructed before May 31, 1972, and are considered "grandfathered" from construction permitting requirements.	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	DIESEL	1341	HP	Particulate matter, total < 2.5 µ (TPM2.5)	COMBUSTION CONTROL.	0.44	LB/HR		BACT-PSD	N/A	0			0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle power islands. Each CT and duct burner will exclusively fire pipeline-quality natural gas. The HRSGs will be equipped with selective catalytic reduction (SCR) to minimize nitrogen oxide (NOx) emissions and oxidation catalysts to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions from the CTs and DB's. The Project will also include several pieces of ancillary equipment. The list of equipment includes: One fuel gas dew-point heater - natural gas fired, common for all CTs Two CT inlet evaporative coolers - one for each CT (not emissions sources) Two air-cooled condensers (ACCs) - one for each HRSG (not emissions sources) One auxiliary boiler, natural gas-fired One diesel engine powered emergency generator One diesel engine powered fire water pump Diesel fuel, lubricating oil, and aqueous ammonia storage tanks The project once operational will produce 1050 MW Electric Generation	Fire Pump Engine	diesel	0		Particulate matter, total < 2.5 µ (TPM2.5)		2	HP-HR		BACT-PSD	NSPS	0.006	TPY	12-MONTH ROLLING BASIS	0		
*SC-0193	MERCEDES BENZ VANS, LLC	MERCEDES BENZ VANS, LLC	SC	0560-0385-CA	336112	04/15/2016 ACT	Mercedes-Benz Vans, LLC (Mercedes-Benz Vans) owns and operates a van assembly plant in Ladson, Charleston County, South Carolina (the Charleston plant). Mercedes-Benz Vans submitted a Prevention of Significant Deterioration (PSD) construction and operating permit application in for the expansion of existing assembly processes and addition of new processes, including a body shop, paint shop, and energy center.	Emergency Generators and Fire Pump	No. 2 Fuel Oil	1500	hp	Particulate matter, total (TPM)	Meet emission standards of 40 CFR 60, Subpart IIII	100	HRS/YR	12 MONTH ROLLING SUM	BACT-PSD		0			0		
*SC-0193	MERCEDES BENZ VANS, LLC	MERCEDES BENZ VANS, LLC	SC	0560-0385-CA	336112	04/15/2016 ACT	Mercedes-Benz Vans, LLC (Mercedes-Benz Vans) owns and operates a van assembly plant in Ladson, Charleston County, South Carolina (the Charleston plant). Mercedes-Benz Vans submitted a Prevention of Significant Deterioration (PSD) construction and operating permit application in for the expansion of existing assembly processes and addition of new processes, including a body shop, paint shop, and energy center.	Emergency Generators and Fire Pump	No. 2 Fuel Oil	1500	hp	Particulate matter, total < 2.5 µ (TPM2.5)	Meet the standards of 40 CFR 60, Subpart IIII	100	HR/YR	12 MONTH ROLLING SUM	BACT-PSD		0			0		
*SC-0193	MERCEDES BENZ VANS, LLC	MERCEDES BENZ VANS, LLC	SC	0560-0385-CA	336112	04/15/2016 ACT	Mercedes-Benz Vans, LLC (Mercedes-Benz Vans) owns and operates a van assembly plant in Ladson, Charleston County, South Carolina (the Charleston plant). Mercedes-Benz Vans submitted a Prevention of Significant Deterioration (PSD) construction and operating permit application in for the expansion of existing assembly processes and addition of new processes, including a body shop, paint shop, and energy center.	Emergency Generators and Fire Pump	No. 2 Fuel Oil	1500	hp	Particulate matter, total < 10 µ (TPM10)	Must meet the standards of 40 CFR 60, Subpart IIII	100	HR/YR	12 MONTH ROLLING SUM	BACT-PSD		0			0		
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	TX	118239, N200	325311	04/01/2015 ACT	Ammonia production with hydrogen imported	Emergency Diesel Generator	Diesel	1500	hp	Particulate matter, filterable (FPM)	Minimized hours of operations Tier II engine	0.15	LB/H		OTHER CASE-BY-CASE	NSPS , MACT	0.01	T/YR		0		
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	TX	118239, N200	325311	04/01/2015 ACT	Ammonia production with hydrogen imported	Emergency Diesel Generator	Diesel	1500	hp	Particulate matter, filterable < 10 µ (FPM10)	Minimized hours of operations Tier II engine	0.15	LB/H		OTHER CASE-BY-CASE	NSPS , MACT	0.01	T/YR		0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	TX	118239, N200	325311	04/01/2015 ACT	Ammonia production with hydrogen imported	Emergency Diesel Generator	Diesel	1500	hp	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Minimized hours of operations Tier II engine	0.15	LB/H		OTHER CASE-BY-CASE	NSPS , MACT	0.01	T/YR		0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency generator	DIESEL	0		Particulate matter, filterable < 10 Âµ (FPM10)	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency generator	DIESEL	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency firewater pumps		0		Particulate matter, filterable (FPM)	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency firewater pumps		0		Particulate matter, filterable < 10 Âµ (FPM10)	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency firewater pumps		0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers, flares, cooling towers, wastewater treatment plant, loadout facilities, miscellaneous auxiliary support facilities, and associated MSS.	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	Ultra-low Sulfur Diesel	0		Particulate matter, filterable (FPM)	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	0			0		
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers, flares, cooling towers, wastewater treatment plant, loadout facilities, miscellaneous auxiliary support facilities, and associated MSS.	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	Ultra-low Sulfur Diesel	0		Particulate matter, filterable < 10 Âµ (FPM10)	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	0			0		
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers, flares, cooling towers, wastewater treatment plant, loadout facilities, miscellaneous auxiliary support facilities, and associated MSS.	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	Ultra-low Sulfur Diesel	0		Particulate matter, total < 2.5 Âµ (TPM2.5)	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	0			0		
*TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		TX	156571, PSDTX1564, GHGPSDTX195		09/09/2020 ACT	new polyethylene plant that will produce both LLDPE and HDPE	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Particulate matter, filterable (FPM)	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		0			0		
*TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		TX	156571, PSDTX1564, GHGPSDTX195		09/09/2020 ACT	new polyethylene plant that will produce both LLDPE and HDPE	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Particulate matter, filterable < 10 Âµ (FPM10)	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		0			0		
*TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		TX	156571, PSDTX1564, GHGPSDTX195		09/09/2020 ACT	new polyethylene plant that will produce both LLDPE and HDPE	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		0			0		
*TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	160299, PSDTX1576, GHGPSDTX200	325998	09/16/2020 ACT	a new renewable diesel fuels plant that will produce renewable diesel fuel and other renewable fuels.	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Particulate matter, filterable (FPM)	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		0			0		
*TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	160299, PSDTX1576, GHGPSDTX200	325998	09/16/2020 ACT	a new renewable diesel fuels plant that will produce renewable diesel fuel and other renewable fuels.	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Particulate matter, filterable < 10 Âµ (FPM10)	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		0			0		
*TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	160299, PSDTX1576, GHGPSDTX200	325998	09/16/2020 ACT	a new renewable diesel fuels plant that will produce renewable diesel fuel and other renewable fuels.	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		0			0		
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT		WI	18-JJW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Visible Emissions (VE)	The available options described for controlling visible emissions are generally the controls for controlling particulate matter, sulfur dioxide, and nitrogen oxides emissions.	10	%	6-MINUTE AVERAGE	BACT-PSD	NSPS , NESHAP	0			0		
*WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	SIO INTERNATIONAL	WI	18-JJW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Visible Emissions (VE)	The available options described for controlling visible emissions are generally the controls for controlling particulate matter, sulfur dioxide, and nitrogen oxides emissions.	10	%	6-MINUTE AVERAGE	BACT-PSD	NSPS , NESHAP	0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	Emergency Generators	Ultra-low sulfur diesel (no more than 15	0		Particulate matter, filterable (FPM)	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	Emergency Generators	Ultra-low sulfur diesel (no more than 15	0		Particulate matter, filterable < 10 Âµ (FPM10)	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	Emergency Generators	Ultra-low sulfur diesel (no more than 15	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Visible Emissions (VE)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	20	%		BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

PM/PM10/PM2.5

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices, burn ultra-low sulfur diesel fuel and be NSPS compliant.	0.69	LB/H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Ultra low-sulfur diesel fuel.	0.69	LB/H	HOURLY	BACT-PSD	SIP	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Particulate matter, total < 10 Âµ (TPM10)	Good combustion practices, burn ultra low sulfur diesel fuel, and be NSPS compliant.	2.7	LB/H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Particulate matter, total < 2.5 Âµ (TPM2.5)	Ultra low sulfur diesel fuel.	2.7	LB/H	HOURLY	BACT-PSD	SIP	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0728	PEONY CHEMICAL MANUFACTURING FACILITY	BASF	TX	118239, N200	325311	04/01/2015 ACT	Ammonia production with hydrogen imported	Emergency Diesel Generator	Diesel	1500	hp	Nitrogen Oxides (NOx)	Minimized hours of operations Tier II engine	0.0218	G/HP HR		LAER	NSPS , MACT	0.35	TPY		0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Nitrogen Oxides (NOx)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	0.4	G/KW-H		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Nitrogen Oxides (NOx)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	0.4	G/KW-HR		BACT-PSD		0			0		
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Emergency Generator	distillate fuel oil	3755	HP	Nitrogen Oxides (NOx)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.67	G/KW-H		BACT-PSD		0			0		
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW (P103 and	Fire Pump Engine - 460 BHP	Diesel	0		Nitrogen Oxides (NOx)		2.6	G/HP-H	EXPRESSED AS NO2	OTHER CASE-BY-CASE	OTHER	2.6	LB/H		0.13	T/YR	
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	08Å-00045A	221112	10/10/2012 ACT	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include:	Fire Pump	Diesel	0		Nitrogen Oxides (NOx)		2.6	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	2.6	LB/H		2.6	G/B-HP-H	
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	2.83	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	2.83	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	R2-PSD 1	221119	04/10/2014 ACT	Energy Answers Arecibo is a new resource recovery facility capable of producing up to 77 megawatts (MW) of electrical power while combusting municipal solid waste, as the primary fuel.	Emergency Diesel Generator	ULSD Fuel oil # 2	0		Nitrogen Oxides (NOx)		2.85	G/B-HP-H		BACT-PSD		4.2	LB/H		0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency fire pump EU-6008	Diesel	750	HP	Nitrogen Oxides (NOx)	Engine that complies with Table 4 to Subpart IIII of Part 60	4	G/KWH	COMBINED NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	0			0		
MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	122-17	561110	03/22/2018 ACT	The existing Flat Rock Assembly Plant (FRAP) is an automotive manufacturing plant which consists of a stamping operation, a body shop, a paint shop, and a final assembly shop. The permit application is for the proposed installation of an electronic data center (EDC) with backup emergency generators at FRAP.	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	Diesel	500	KW	Nitrogen Oxides (NOx)	Good combustion practices.	4	G/KW-H	HOURLY; NMHC+NOX	BACT-PSD	NSPS , SIP	8.47	LB/H	HOURLY; NOX	0		
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	0160-0023	327992	02/08/2012 ACT	PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS.	FIRE PUMP	DIESEL	500	HP	Nitrogen Oxides (NOx)	PURCHASE OF CERTIFIED ENGINE BASED ON NSPS, SUBPART IIII.	4	GR/KW-H		BACT-PSD	NSPS	0			0		
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	0160-0023	327992	02/08/2012 ACT	PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS.	EMERGENCY GENERATORS 1 THRU 8	DIESEL	757	HP	Nitrogen Oxides (NOx)	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H		BACT-PSD	NSPS	0			0		
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	16060032	221112	07/30/2018 ACT	The proposed facility is designed to generate electric power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would burn natural gas and ultra-low sulfur diesel (ULSD) as a backup fuel. Other units include an auxiliary boiler, fuel heater, engines, natural gas piping and	Emergency Engines	Ultra-low sulfur diesel	0		Nitrogen Oxides (NOx)		0			LAER	NSPS	0			0		
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Nitrogen Oxides (NOx)	Good combustion design	4.97	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	0.25	T/YR	NMHC+NOX. SEE NOTES.	3	G/BHP-H	NMHC+NOX. SEE NOTES.
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	PSD-FL-416, 0550063-001-AC	221119	09/23/2011 ACT	THIS PROJECT INVOLVES THE CONSTRUCTION OF A SUGARCANE AND SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY WITH A MAXIMUM ANNUAL ETHANOL (C2H5OH) PRODUCTION RATE OF 36 MILLION GALLONS PER YEAR (MGPY). THE CANE (I.E. THE SUGARCANE AND SORGHUM) WILL BE GROWN ON NEARBY FARMLAND. THE JUICE WILL BE SQUEEZED FROM THE FEEDSTOCK	600 HP Emergency Equipment	Ultra-Low Sulfur Oil	0		Nitrogen Oxides (NOx)	See Pollutant Notes.	3	G/HP-H		BACT-PSD	NSPS	0			0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process Block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	Fire pump engine	Ultra-low sulfur diesel	15	gal/hr	Nitrogen Oxides (NOx)		3	GM/HP-HR		LAER		0.05	TONS	12-MONTH ROLLING BASIS	0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	11-00536A	221112	09/02/2016 ACT	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric	Emergency Fire Pump Engine	ULSD	0		Nitrogen Oxides (NOx)		3	G/BHP-HR		LAER	NSPS	0			0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	This Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Fire Pump Engine	diesel	0		Nitrogen Oxides (NOx)		3	G/HP-HR		LAER	NSPS	0.08	TPY	12-MONTH ROLLING BASIS	0		
*VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	52610-1	221112	06/24/2019 ACT	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/hr natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Emegency Fire Water Pump	Ultra Low Sulfur Diesel	500	HR/YR	Nitrogen Oxides (NOx)	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	3	G/HP-HR		BACT-PSD	NSPS , SIP	0.7	T/YR		0		
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	Nitrogen Oxides (NOx)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			3	G/B-HP-H	NMHC+NOX
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Firewater Pumps	Diesel Fuel	634	kW	Nitrogen Oxides (NOx)	Good Combustion and Operating Practices.	3.1	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*AK-0085	GAS TREATMENT PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of one integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42-	One (1) Black Start Generator Engine	ULSD	186.6	gph	Nitrogen Oxides (NOx)	Good combustion practices, limit operation to 500 hours per year.	3.3	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS , NESHAP	0			0		
CA-1221	PACIFIC BELL	PACIFIC BELL	CA	2011-APP-001776	517110	12/05/2011 ACT		ICE:Emergency-Compression Ignition	diesel	3634	bhp	Nitrogen Oxides (NOx)	Tier 2 certified and 50 hr/yr for M&T limit	3.5	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Nitrogen Oxides (NOx)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR		BACT-PSD		0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	horsepower	Nitrogen Oxides (NOx)	Compliance with NSPS Subpart IIII	6.6	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	Diesel	1474	horsepower	Nitrogen Oxides (NOx)	Compliance with NSPS Subpart IIII	19.23	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
CA-1220	SAN DIEGO INTERNATIONAL AIRPORT	SAN DIEGO INTERNATIONAL AIRPORT	CA	2011-APP-001787	488119	10/03/2011 ACT		ICE:Emergency-Compression Ignition	diesel	1881	BHP	Nitrogen Oxides (NOx)	Tier 2 certified and 50 hr/y M&T limit	3.9	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0			0		
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT		WI	18-JJW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Nitrogen Oxides (NOx)	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	SIO INTERNATIONAL	WI	18-JJW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Nitrogen Oxides (NOx)	Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.	5.36	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Large Emergency Engines (>50kW)	Diesel Fuel	5364	HP	Nitrogen Oxides (NOx)	Good Combustion and Operating Practices	5.6	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	P0110840	221112	06/18/2013 ACT	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency generator	diesel	2250	KW	Nitrogen Oxides (NOx)	Purchased certified to the standards in NSPS Subpart IIII	27.8	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	6.95	T/YR	PER ROLLING 12-MONTHS	0		SEE NOTES
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	P0113762	221112	11/05/2013 ACT	Natural gas fired combined cycle gas turbine electric generating station of nominal capacity of 742 MW	Emergency generator (P003)	diesel	1112	KW	Nitrogen Oxides (NOx)	Purchased certified to the standards in NSPS Subpart IIII	13.74	LB/H		BACT-PSD	NSPS	3.44	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	P0117655	221112	08/25/2015 ACT	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2346	HP	Nitrogen Oxides (NOx)	State-of-the-art combustion design	21.6	LB/H		BACT-PSD	NSPS	5.41	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	P0119495	221112	09/23/2016 ACT	1150 MW combined-cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2947	HP	Nitrogen Oxides (NOx)	State-of-the-art combustion design	27.18	LB/H		BACT-PSD	NSPS	6.8	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Emergency Generator (P009)	Diesel fuel	5000	HP	Nitrogen Oxides (NOx)	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	5.5	LB/H		BACT-PSD	NSPS	0.3	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	P0122331	221112	09/07/2017 ACT	940 MW combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Nitrogen Oxides (NOx)	State-of-the-art combustion design	16.07	LB/H		BACT-PSD	NSPS	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	P0121049	221112	09/27/2017 ACT	Combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Nitrogen Oxides (NOx)	State-of-the-art combustion design	16.1	LB/H		BACT-PSD	NSPS	4.02	T/YR	PER ROLLING 12 MONTH PERIOD	4.8	G/B-HP-H	SEE NOTES
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Nitrogen Oxides (NOx)	Combustion practices per the manufacturer's operating manual.	23.21	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	1.16	T/YR	NMHC+NOX. SEE NOTES.	4.77	G/BHP-H	NMHC+NOX. SEE NOTES.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Nitrogen Oxides (NOx)	Good combustion design	24.71	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	1.24	T/YR	NMHC+NOX. SEE NOTES.	4.8	G/BHP-H	NMHC+NOX. SEE NOTES.
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	P0123395	331111	02/09/2018 ACT	Hot briquetted iron production	Emergency diesel-fired generator (P007)	Diesel fuel	2682	HP	Nitrogen Oxides (NOx)	Comply with NSPS 40 CFR 60 Subpart IIII	28.2	LB/H		BACT-PSD	NSPS	7.05	T/YR	PER ROLLING 12 MONTH PERIOD	4.8	G/BHP-H	SEE NOTES
OH-0377	HARRISON POWER	HARRISON POWER	OH	P0122266	221112	04/19/2018 ACT	1000 MW natural gas-fired combined cycle combustion turbine plant	Emergency Diesel Generator (P003)	Diesel fuel	1860	HP	Nitrogen Oxides (NOx)	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	19.68	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	0.98	T/YR	NMHC+NOX. SEE NOTES.	4.8	G/BHP-H	NMHC+NOX. SEE NOTES.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Nitrogen Oxides (NOx)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	37.41	LB/H	SEE NOTES.	BACT-PSD	NSPS	1.87	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	4.8	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Nitrogen Oxides (NOx)	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturer's operating manual	14.96	LB/H	SEE NOTES.	BACT-PSD	NSPS	0.75	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	4.8	G/BHP-H	SEE NOTES
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	EMERGENCY GENERATORS (EU014A AND EU-014B)	DISTILLATE OIL	3600	HP EACH	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	4.42	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		500	H/YR EACH		0		
MI-0394	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER-WARREN	MI	160-11	336211	02/29/2012 ACT	Automotive research	Nine (9) DRUPS Emergency Generators	Diesel	3010	KW	Nitrogen Oxides (NOx)	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	EACH GENERATOR ENGINE	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	0			0		
MI-0395	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER--WARREN	MI	160-11A	336211	07/13/2012 ACT	Automotive research	Nine (9) DRUPS Emergency Generators	Diesel	3010	KW	Nitrogen Oxides (NOx)	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	5.98	G/KW-H	EACH GENERATOR ENGINE	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	4.46	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	DIESEL-FIRED EMERGENCY GENERATOR	NO. 2 FUEL OIL	4690	B-HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	4.46	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Nitrogen Oxides (NOx)	good combustion practices	6	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		6.61	TONS/YR	ROLLING 12 MONTH TOTAL	0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS	0			0		
WV-0027	INWOOD	KNAUF INSULATION INC.	WV	R14-0015M	327993	09/15/2017 ACT	Insulation Manufacturing Facility	Emergency Generator - ESDG14	ULSD	900	bhp	Nitrogen Oxides (NOx)	Engine Design	4.77	G/HP-HR		BACT-PSD	NSPS , MACT	0			0		
FL-0332	HIGHLANDS BIOREFINERY AND COGENERATION PLANT	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	PSD-FL-416, 0550063-001-AC	221119	09/23/2011 ACT	THIS PROJECT INVOLVES THE CONSTRUCTION OF A SUGARCANE AND SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY WITH A MAXIMUM ANNUAL ETHANOL (C2H5OH) PRODUCTION RATE OF 36 MILLION GALLONS PER YEAR (MGPY). THE CANE (I.E. THE SUGARCANE AND SORGHUM) WILL BE GROWN ON NEARBY FARMLAND. THE JUICE WILL BE SQUEEZED FROM THE FEEDSTOCK	2000 KW Emergency Equipment		0		Nitrogen Oxides (NOx)	See Pollutant Notes.	6.4	G/KW-H		BACT-PSD	NSPS	0			0		
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	17040013	221112	12/31/2018 ACT	The proposed facility is designed to generate electric power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would only burn natural gas. Other units include an auxiliary boiler, fuel heater, emergency engines, natural gas piping and components, circuit breakers and roadways	Emergency Engine	Ultra-Low Sulfur Diesel	1500	kW	Nitrogen Oxides (NOx)		6.4	G/KW-HR		LAER	NSPS	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency generator EU-6006	Diesel	2800	HP	Nitrogen Oxides (NOx)	Tier II diesel engine	6.4	G/KWH	TIER II NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	0			0		
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	06/04/2015 ACT	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Emergency Generator Engines	Diesel	2922	hp (each)	Nitrogen Oxides (NOx)	Complying with 40 CFR 60 Subpart IIII	6.4	G/KW-HR		BACT-PSD		0			0		
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUEMENGINE (Diesel fuel emergency engine)	Diesel Fuel	22.68	MMBTU/H	Nitrogen Oxides (NOx)	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (North Plant): Emergency Engine	Diesel	1341	HP	Nitrogen Oxides (NOx)	Good combustion practices and meeting NSPS Subpart IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (South Plant): Emergency Engine	Diesel	1341	HP	Nitrogen Oxides (NOx)	Good combustion practices and meeting NSPS IIII requirements.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
MI-0434	FLAT ROCK ASSEMBLY PLANT	FORD MOTOR COMPANY	MI	122-17	561110	03/22/2018 ACT	The existing Flat Rock Assembly Plant (FRAP) is an automotive manufacturing plant which consists of a stamping operation, a body shop, a paint shop, and a final assembly shop. The permit application is for the proposed installation of an electronic data center (EDC) with backup emergency generators at FRAP.	EUENGINE01 through EUENGINE08	Diesel	3633	BHP	Nitrogen Oxides (NOx)	Good combustion practices.	6.4	G/KW-H	HOURLY; EACH ENGINE; NMHC+NOX	BACT-PSD	NSPS , SIP	42.6	LB/H	HOURLY; EACH ENGINE; NOX	0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	19-18	221112	07/16/2018 ACT	Natural gas combined-cycle power plant	EUEMENGINE: Emergency engine	Diesel	2	MW	Nitrogen Oxides (NOx)	State of the art combustion design.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Nitrogen Oxides (NOx)	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Nitrogen Oxides (NOx)	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16B	221112	11/26/2019 ACT	Natural gas combined cycle power plant	EUEMENGINE (diesel fuel emergency engine)	diesel fuel	22.68	MMBTU/H	Nitrogen Oxides (NOx)	Good Combustion Practices and meeting NSPS Subpart IIII requirements	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 1,000 MW combined-cycle electric power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	DIESEL FUEL	0		Nitrogen Oxides (NOx)	Good Combustion Practices/Maintenance	6.4	G/KW	PER HR	N/A		10.6	T/YR	12 MO ROLLING TOTAL	0		
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	PSD-LA-767	221112	09/26/2013 ACT		2000 KW Diesel Fired Emergency Generator Engine	Diesel	20.4	MMBTU/hr	Nitrogen Oxides (NOx)	Good combustion and maintenance practices, and compliance with NSPS 40 CFR 60 Subpart IIII	33.07	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	1.38	T/YR	ANNUAL MAXIMUM	4.78	G/B-HP-H	12 MONTH AVERAGE
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	PSD-LA-804	221112	08/31/2016 ACT	The St. Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.	SCPS Emergency Diesel Generator 1	Diesel	2584	HP	Nitrogen Oxides (NOx)	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	27.34	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	6.84	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-HR	

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 1	Diesel	5364	HP	Nitrogen Oxides (NOx)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	2.63	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 2	Diesel	5364	HP	Nitrogen Oxides (NOx)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	52.58	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	2.63	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 1	Diesel	751	HP	Nitrogen Oxides (NOx)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.23	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 2	Diesel	751	HP	Nitrogen Oxides (NOx)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.6	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.23	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT03	211111	01/23/2015 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY.	Emergency Camp Generators	Ultra Low Sulfur Diesel	2695	hp	Nitrogen Oxides (NOx)		4.8	GRAMS/HP-H		BACT-PSD		0			0		
CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	CA	SE 09-01	221112	10/18/2011 ACT	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	EMERGENCY IC ENGINE	DIESEL	2683	HP	Nitrogen Oxides (NOx)		6.4	G/KW-H	3-HR AVG	BACT-PSD		4.8	G/HP-H	3-HR AVG	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Nitrogen Oxides (NOx)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEALRY	0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Nitrogen Oxides (NOx)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	4.8	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	CPCN CASE NO. 9327	221119	04/08/2014 ACT	1000 MEGAWATT COMBINED CYCLE NATURAL GAS FIRED POWER PLANTFACILITY-WIDE PM10 EMISSION LIMIT = 278 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT = 272 TONS/YR FACILITY-WIDE SAM EMISSION LIMIT = 96 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 3,498,026 TONS/YR	EMERGENCY GENERATOR 1	ULTRA LOW SULFU DIESEL	2250	KW	Nitrogen Oxides (NOx)	LIMITED OPERATING HOURS, USE OF ULTRA- LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES	4.8	G/HP-H		LAER	NSPS	6.4	G/KW-H		0		
MD-0043	PERRYMAN GENERATING STATION	CONSTELLATION POWER SOURCE GENERATION, INC.	MD	PSC CASE NO. 9136	221119	07/01/2014 ACT	120 MEGAWATT SIMPLE CYCLE NATURAL GAS FIRED POWER PLANT FACILITY & PROJECT-WIDE EMISSION LIMITS: PM10 = 43.0 TONS/YR PM2.5 = 43.0 TONS/YR NOX = 58.5 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1300	HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES, LIMITED HOURS OF OPERATION, AND EXCLUSIVE USE OF ULSD	4.8	G/HP-H		LAER	NSPS	6.4	G/KW-H		0		
MD-0044	COVE POINT LNG TERMINAL	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	1500 MEGAWATT NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1550	HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	COMBINED NOX + NMHC	LAER	NSPS	6.4	G/KW-H	COMBINED NOX + NMHC	0		
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	51-13	221112	11/01/2013 ACT	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	THE EMERGENCY (2) 1,000kW diesel-fueled emergency reciprocating internal combustion	Diesel	1000	kW	Nitrogen Oxides (NOx)	Good combustion practices	4.8	G/B-HP-H	TEST PROTOCOL; EACH UNIT	BACT-PSD	SIP	0			0		
PA-0310	CPV FAIRVIEW ENERGY CENTER	CPV FAIRVIEW, LLC	PA	11-00536A	221112	09/02/2016 ACT	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric	Emergency Generator Engines	ULSD	0		Nitrogen Oxides (NOx)		4.8	G/BHP-HR		LAER	NSPS	0			0		
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Emergency Diesel GEN	Ultra Low Sulfur Diesel	500	H/YR	Nitrogen Oxides (NOx)	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	4.8	G/HP H		BACT-PSD	NSPS , SIP	9.6	T/YR	12 MO ROLLING AV	0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Emergency Generator	Diesel	2015.7	HP	Nitrogen Oxides (NOx)		0			BACT-PSD	NSPS	0			4.8	G/HP-HR	NMHC + NOX
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	Diesel	2922	HP	Nitrogen Oxides (NOx)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			4.8	G/B-HP-H	NMHC+NOX
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Tunnel Furnace Emergency Generator (EP 08-06)	Diesel	2937	HP	Nitrogen Oxides (NOx)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			4.8	G/B-HP-H	NMHC+NOX
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Caster B Emergency Generator (EP 08-07)	Diesel	2937	HP	Nitrogen Oxides (NOx)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			4.8	G/B-HP-H	NMHC+NOX
KY-0115	NUCOR STEEL GALLATIN, LLC	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Air Separation Unit Emergency Generator (EP 08-08)	Diesel	700	HP	Nitrogen Oxides (NOx)	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			4.8	G/B-HP-H	NMHC+NOX
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	81-11	221112	11/17/2011 ACT	Utility--Natural gas fired combustion turbine	Diesel fuel-fired combustion engine (RICE)	Diesel	732	HP	Nitrogen Oxides (NOx)	Good combustion practices	4.85	G/HP-H	TEST	BACT-PSD	NSPS , NESHAP , OTHER	0			0		
PA-0286	MOXIE ENERGY LLC/PATRIOT GENERATION PLT	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW (P103 and	EMERGENCY GENERATOR-ENGINE	Diesel	0		Nitrogen Oxides (NOx)		4.93	GM/B-HP-H		OTHER CASE-BY-CASE	OTHER	16	LB/H	EACH UNIT	0.8	T/YR	EACH UNIT
PA-0278	MOXIE LIBERTY LLC/ASYLUM POWER PL T	MOXIE ENERGY LLC	PA	08Â-00045A	221112	10/10/2012 ACT		Emergency Generator	Diesel	0		Nitrogen Oxides (NOx)		4.93	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0			4.93	G/B-HP-H	
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of (1) nominal 2 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Emergency Generator		0		Nitrogen Oxides (NOx)		4.93	G/HP-HR		LAER	NSPS	0.4	TPY	12-MONTH ROLLING BASIS	0		
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	2008-302-C(M-1)PSD	221112	07/02/2013 ACT	WFEC operates the Mooreland Generating Station to generate wholesale electricity which is transmitted over WFEC's system. The facility was originally constructed in 1963. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma and part of New Mexico. The Mooreland Generating Station currently consists of three high-pressure boilers	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	DIESEL	1341	HP	Nitrogen Oxides (NOx)	COMBUSTION CONTROL	0.011	LB/HP-HR		BACT-PSD	NSPS	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MI-0394	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER-WARREN	MI	160-11	336211	02/29/2012 ACT	Automotive research	Four (4) Emergency Generators	Diesel	2280	KW	Nitrogen Oxides (NOx)	No add-on controls, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	6.93	G/KW-H	EACH GENERATOR ENGINE	BACT-PSD	NESHAP , NSPS , SIP , OPERATING PERMIT	0			0		
*MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	210-18	221112	08/21/2019 ACT	New power plant	FGEMENGINE	Diesel	1100	KW	Nitrogen Oxides (NOx)		5.3	G/HP-H	HOURLY; EACH ENGINE	BACT-PSD	NSPS	0			0		
MI-0395	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER--WARREN	MI	160-11A	336211	07/13/2012 ACT	Automotive research	Four (4) Emergency Generators	Diesel	2500	KW	Nitrogen Oxides (NOx)	No add-on control, but ignition timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	7.13	G/KW-H	EACH GENERATOR ENGINE	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	0			0		
MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	160-11B	336211	01/14/2015 ACT	Automotive research	Four (4) emergency engines in FG-BACKUPGENS	Diesel	2710	KW	Nitrogen Oxides (NOx)	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	7.13	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	0			0		
DC-0009	BLUE PLAINS ADVANCED WASTEWATER TREATEMENT PLANT	DISTRICT OF COLUMBIA WATER AND SEWER AUTHORITY	DC	6372-A1	221320	03/15/2012 ACT	Wastewater treatment plant using thermal hydrolysis pretreatment process prior to digesting wastewater sludge with anaerobic digesters. Digester gas is used as fuel for combined heat and power (CHP) process.	Diesel Emergency Generator	Ultra-low Sulfur Diesel	2682	hp	Nitrogen Oxides (NOx)		31.87	LB/HR		LAER	NSPS , SIP , OPERATING PERMIT	5.39	G/HP-HR		0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	2000 kW Emergency Generator	Ultra-low sulfur Diesel	0		Nitrogen Oxides (NOx)		5.45	GM/HP-HR		LAER		0.81	TONS	12-MONTH ROLLING BASIS	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The permit under review is for gold mine located 22 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Black Start and Emergency Internal Cumbustion Engines	Diesel	1500	kWe	Nitrogen Oxides (NOx)	Good Combustion Practices	8	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
MI-0418	WARREN TECHNICAL CENTER	GENERAL MOTORS TECHNICAL CENTER - WARREN	MI	160-11B	336211	01/14/2015 ACT	Automotive research	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	Diesel	3490	KW	Nitrogen Oxides (NOx)	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.	8	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	BACT-PSD	NSPS , NESHAP , SIP , OPERATING PERMIT	0			0		
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033-X014 - X020	331111	07/22/2014 ACT	STEEL MILL ADDING 2ND BAGHOUSE TO EAF, AUSTENITIZING FURNACE, TEMPERING FURNACE, VACUUM DEGASSER, PLASMA TORCHES, AND EMERGENCY GENERATORS	DIESEL FIRED EMERGENCY GENERATOR	DIESEL	800	HP	Nitrogen Oxides (NOx)		0.015	LB/HP-H		BACT-PSD	NSPS , MACT	0			0		
*PA-0282	JOHNSON MATTHEY INC/CATALYTIC SYSTEMS DIV	JOHNSON MATTHEY INC	PA	15-0027K	336399	06/01/2012 ACT	This Plan Approval has been issued to Johnson Matthey, Inc. to establish a plant-wide applicability limit (PAL) for NOx emissions from the facility.	650-KW BACKUP DIESEL GENERATOR	Diesel / #2 Oil	45.8	GAL/H	Nitrogen Oxides (NOx)		6.9	G/HP-H		OTHER CASE-BY-CASE	OTHER	11.34	LB/H		0		
FL-0327	ANADARKO - PHEONIX PROSPECT	ANADARKO PETROLEUM COMPANY	FL	OCS-EPA-R4005	213112	06/13/2011 ACT	The proposed project, known as the Pheonix Prospect, will mobilize the Discoverer Spirit, a work boat, a crew boat and a anchor handling boat to drill a single exploration well on the OCS in Lloyd Ridge Lease Block 410 to determine if natural gas reserves are present in this location. The wellâ€™s objective depth is 16,100 feet true vertical depth sub-sea or 6,300 feet below the mud line of the	Emergency Engine	Diesel	0		Nitrogen Oxides (NOx)	Limited use of 24 hours/week and recordkeeping of operation.	9.4	TONS PER PROJECT		BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Engine	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices, based on the current manufacturer's specifications for this engine	0.4	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Fire Pump Engine	Diesel	0		Nitrogen Oxides (NOx)	Use of good combustion practices, based on the current manufacturer's specifications for this engine	0.02	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - Development Driller 1	Diesel	2229	hp	Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	1.6	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - C.R. Luigs	diesel	2064	hp	Nitrogen Oxides (NOx)	Use of good combustion practices based on the current manufacturer's specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	1.49	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit, using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Emergency Diesel Engine	Diesel	3300	hp	Nitrogen Oxides (NOx)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
FL-0348	MURPHY EXPLORATION & PRODUCTION CO.	MURPHY EXPLORATION & PRODUCTION CO.	FL	OCS-EPA-R4009	213111	05/15/2012 ACT	The facility consists of the dynamically positioned diamond offshore deepwater drilling vessel Ocean Confidence and an associated support fleet to conduct exploratory drilling and well completion for up to 90 calendar days within a two year period at a single well location within its Lloyd Ridge lease block 317. The drill site is located on the OCS in the Gulf of Mexico, approximately 135 miles	Emergency Electrical Generator	Diesel	1100	hp	Nitrogen Oxides (NOx)	Use of good combustion and maintenance practices based on the current manufacturer's specifications for this engine.	0.22	TONS	TOTAL DURATION OF PROJECT	BACT-PSD	OPERATING PERMIT	0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0			BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0			BACT-PSD		0			0		
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		2682	HP	Nitrogen Oxides (NOx)	Comply with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	1.37	TPY	ANNUAL MAXIMUM	0		
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators: No. 1 & No. 2	Diesel	1341	HP	Nitrogen Oxides (NOx)	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII	14.16	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.71	TPY	ANNUAL MAXIMUM	4.8	G/BHP-HR	
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325211	05/23/2014 ACT	The Low Density Polyethylene (LDPE) Unit will produce LDPE by the high pressure polymerization of ethylene.	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105,	Diesel	2682	HP	Nitrogen Oxides (NOx)	Compliance with 40 CFR 60 Subpart IIII, operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel	27.37	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT , NSPS	1.37	TPY	ANNUAL MAXIMUM	0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Diesel Engines (Emergency)	Diesel	4023	hp	Nitrogen Oxides (NOx)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	emergency generator engines (6 units)	diesel	3353	hp	Nitrogen Oxides (NOx)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Emergency Generator Engines (4 units)	Diesel	0		Nitrogen Oxides (NOx)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Firewater pump Engines (4 units)	diesel	896	hp (each)	Nitrogen Oxides (NOx)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 3 Engine	Diesel Fuel	600	hp	Nitrogen Oxides (NOx)	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 4 Engine	Diesel Fuel	600	hp	Nitrogen Oxides (NOx)	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
*LA-0350	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-744(M2)	331210	03/28/2018 ACT	A steel tube manufacturing facility from scrap metal	emergency generators (3 units) EQT0039, EQT0040, EQT0041		0		Nitrogen Oxides (NOx)	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Generator Diesel Engines	Diesel Fuel	550	hp	Nitrogen Oxides (NOx)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Fire Water Pumps	Diesel Fuel	550	hp	Nitrogen Oxides (NOx)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		
*MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	NE-15-018	611310	06/21/2017 ACT	MIT proposes to construct and operate two new 22 megawatt (MW) combined heat and power (CHP) combustion turbines/heat recovery steam generators and a new cold start engine at its existing Central Utility Plant.	Cold Start Engine	ULSD	19.04	MMBTU/HR	Nitrogen Oxides (NOx)		35.09	LB/HR	1 HR BLOCK AVG	OTHER CASE-BY-CASE	NESHAP , SIP , OPERATING PERMIT , NSPS	5.3	TONS/C12MP	CONSECUTIVE TWELVE MONTH PERIOD	0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	Diesel	500	H/YR	Nitrogen Oxides (NOx)	Certified engines, limited operating hours.	22.6	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	0			0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Dieself fire pump engine (EUFIREPUMP in FGRICE)	Diesel	500	H/YR	Nitrogen Oxides (NOx)	Certified engines, limited operating hours.	3.53	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	Diesel	500	H/YR	Nitrogen Oxides (NOx)	Certified engines, limited operating hours.	21.2	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	Diesel	500	H/YR	Nitrogen Oxides (NOx)	Certified engines, limited operating hours	4.4	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUFIREPUMP in FGRICE (Diesel fire pump engine)	Diesel	500	H/YR	Nitrogen Oxides (NOx)	Certified engines. Limited operating hours.	3.53	LB/H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	SIP	0			0		
NJ-0079	WOODBRIDGE ENERGY CENTER	CPV SHORE, LLC	NJ	18940 - BOP110003	221112	07/25/2012 ACT	Woodbridge Energy Center (WEC), proposed at Woodbridge Township (Middlesex County), New Jersey, 07095, would be a new, highly efficient, 700 MW combined-cycle power generating facility. WEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,307 MMBtu/hr, that will utilize pipeline natural gas only. Heat	Emergency Generator	Ultra Low Sulfur distillate Diesel	100	H/YR	Nitrogen Oxides (NOx)	Use of ULSD diesel oil	21.16	LB/H		LAER	NSPS , OPERATING PERMIT	0			0		
NJ-0080	HESS NEWARK ENERGY CENTER	HESS NEWARK ENERGY CENTER, LLC	NJ	08857/BOP110001	221112	11/01/2012 ACT	HESS Newark Energy Center (Hess-NEC), proposed at City of Newark (Essex County), New Jersey, would be a new, highly efficient, 655 MW combined-cycle power generating facility. Hess-NEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,320 MMBtu/hr,	Emergency Generator	ULSD	200	H/YR	Nitrogen Oxides (NOx)	use of ultra low sulfur diesel (ULSD) a clean fuel	18.53	LB/H		LAER	NSPS , OPERATING PERMIT	0			0		
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	PSEG FOSSIL LLC	NJ	18068/BOP150001	221112	03/10/2016 ACT	751 Cliff Road, Sewaren, New Jersey 07077-1439, Middlesex County, New Jersey. This â€œProjectâ€ to be built at Sewaren would be a 1-on-1 (1 combustion turbine and a single steam turbine) combined-cycle electric generating unit including its ancillary equipment. The electric output of the combined-cycle	Diesel Fired Emergency Generator	ULSD	44	H/YR	Nitrogen Oxides (NOx)	use of ultra low sulfur diesel a clean burning fuel.	42.3	LB/H		LAER	NSPS , OPERATING PERMIT	0			0		
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Emergency generator (P002)	Diesel fuel	1100	KW	Nitrogen Oxides (NOx)	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	29.01	LB/H		BACT-PSD	NSPS	7.25	T/YR	PER ROLLING 12 MONTH PERIOD	8.92	G/B-HP-H	
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	P0125024	331111	02/06/2019 ACT	Merchant Pig Iron Production	Emergency Generators (P005 and P006)	Diesel fuel	3131	HP	Nitrogen Oxides (NOx)	Tier IV engine Tier IV NSPS standards certified by engine manufacturer.	3.45	LB/H		BACT-PSD	NSPS	0.17	T/YR		0.5	G/BHP-H	
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency generator	DIESEL	0		Nitrogen Oxides (NOx)	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency firewater pumps		0		Nitrogen Oxides (NOx)	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0879	MOTIVA PORT ARTHUR TERMINAL	MOTIVA ENTERPRISES LLC	TX	7238 AND PSDTX1548	424710	02/19/2020 ACT	This application includes construction of two storage tanks at the 7th Street Yard Farm, six storage tanks at the Port Arthur Terminal, and the refurbishment and reauthorization of Berth 1 at Texaco Island. A VCU will be installed to control Berth 1 loading operations. In addition, loading of benzene and p-xylene is being authorized for Berths 1, 2, 6, and 7. Loading of heavy and light pygas is being	Emergency Firewater Engine	Ultra-low sulfur diesel	0		Nitrogen Oxides (NOx)	Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-resettable runtime meter.	0			BACT-PSD	NSPS , MACT	0			0		
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an ethene unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers, flares, cooling towers, wastewater treatment plant, loadout facilities, miscellaneous auxiliary support facilities, and associated MSS.	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	Ultra-low Sulfur Diesel	0		Nitrogen Oxides (NOx)	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	0			0		
*TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX		TX	156571, PSDTX1564, GHGPSDTX195		09/09/2020 ACT	new polyethylene plant that will produce both LLDPE and HDPE	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Nitrogen Oxides (NOx)	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		0			0		
*TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	160299, PSDTX1576, GHGPSDTX200	325998	09/16/2020 ACT	a new renewable diesel fuels plant that will produce renewable diesel fuel and other renewable fuels.	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Nitrogen Oxides (NOx)	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

NO_X

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
WY-0070	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Diesel Emergency Generator (EP15)	Ultra Low Sulfur Diesel	839	hp	Nitrogen Oxides (NOx)	EPA Tier 2 rated	0			BACT-PSD	NSPS	0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	Emergency Generators	Ultra-low sulfur diesel (no more than 15	0		Nitrogen Oxides (NOx)	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Nitrogen Oxides (NOx)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	4.86	G/KW-HR		BACT-PSD		0			0		
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033-X014 - X020	331111	07/22/2014 ACT	STEEL MILL ADDING 2ND BAGHOUSE TO EAF, AUSTENITIZING FURNACE, TEMPERING FURNACE, VACUUM DEGASSER, PLASMA TORCHES, AND EMERGENCY GENERATORS	DIESEL FIRED EMERGENCY GENERATOR	DIESEL	800	HP	Nitrogen Oxides (NOx)		0.015	LB/HP-H		BACT-PSD	NSPS , MACT	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators No. 1 & No. 2	Diesel	1341	HP	Nitrogen Oxides (NOx)	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII	14.16	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.71	TPY	ANNUAL MAXIMUM	4.8	G/BHP-HR	
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Nitrogen Oxides (NOx)	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Nitrogen Oxides (NOx)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	4.77	G/HP-HR	NMHC + NOX	BACT-PSD	NSPS	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Nitrogen Oxides (NOx)	Good combustion practices and will be NSPS compliant.	6.4	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
TX-0728	BASF	TX	118239, N200	325311	04/01/2015 ACT	Ammonia production with hydrogen imported	Emergency Diesel Generator	Diesel	1500	hp	Carbon Monoxide	Minimized hours of operations Tier II engine	0.0126	G/HP HR		OTHER CASE-BY-CASE	NSPS , MACT	0.2	TPY		0		
PA-0278	MOXIE ENERGY LLC	PA	08Â-00045A	221112	10/10/2012 ACT		Emergency Generator	Diesel	0		Carbon Monoxide		0.13	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.42	LB/H		0.13	G/B-HP-H	
PA-0286	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural-gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW	EMERGENCY GENERATOR-ENGINE	Diesel	0		Carbon Monoxide		0.13	GM/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.42	LB/H	EACH UNIT	0.02	T/YR	EACH UNIT
*MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	210-18	221112	08/21/2019 ACT	New power plant	FGEMENGINE	Diesel	1100	KW	Carbon Monoxide		0.15	G/HP-H	HOURLY; EACH ENGINE	BACT-PSD	NSPS	0			0		
PA-0311	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 2 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined-	Emergency Generator		0		Carbon Monoxide		0.26	G/HP-HR		BACT-PSD	NSPS	0.083	TPY	12-MONTH ROLLING BASIS	0		
MI-0402	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	81-11	221112	11/17/2011 ACT	Utility--Natural gas fired combustion turbine	Diesel fuel-fired combustion engine (RICE)	Diesel	732	HP	Carbon Monoxide	Good combustion practices	0.31	G/HP-H	TEST	BACT-PSD	NESHAP , OTHER , NSPS	0			0		
TX-0872	MAGELLAN PROCESSING, L.P.	TX	118270 PSDTX1398M1 GHGPSDTX62	324110	10/31/2019 ACT	The site can process upwards of 100,000 bbls of condensate daily via two trains. The site uses a series of separation towers, collectively known as a condensate splitter. Condensate is received and refined into light and heavy naphtha, kerosene/distillate, residuum and liquified petroleum gas. The refined materials are either stored into storage tanks or loaded into either a truck or marine	Emergency Generators	ultra low sulfur diesel	0		Carbon Monoxide	Limiting duration and frequency of generator use to 100 hr/yr. Good combustion practices will be used to reduce VOC including maintaining proper air-to-fuel ratio.	0.6	G/KW HR		BACT-PSD	NSPS , MACT	0			0		
*WI-0284		WI	18-JIW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Carbon Monoxide	Good Combustion Practices	0.6	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*WI-0286	SIO INTERNATIONAL	WI	18-JIW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Carbon Monoxide	Good Combustion Practices	0.6	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
NY-0104	CPV VALLEY LLC	NY	3-335600136/00001	221112	08/01/2013 ACT	CPV Valley Energy Center is a 680 MW combined cycle electric generating facility located in Middletown, NY. The combustion turbines are rated at 2,234 MMBTU/H firing natural gas and 2,145 MMBTU/H firing diesel fuel. The duct burners are rated for 500 MMBTU/H firing natural gas. In addition to the turbines their emission limits for the auxiliary boiler (73.5 MMBTU/H),	Emergency generator	ultra low sulfur diesel	0		Carbon Monoxide	Good combustion practice.	0.45	G/BHP-H	1 H	BACT-PSD		0			0		
PA-0278	MOXIE ENERGY LLC	PA	08Â-00045A	221112	10/10/2012 ACT		Fire Pump	Diesel	0		Carbon Monoxide		0.5	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.51	LB/H		0.5	G/B-HP-H	
PA-0309	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3)	Fire pump engine	Ultra-low sulfur diesel	15	gal/hr	Carbon Monoxide		0.5	GM/HP-HR		BACT-PSD		0.009	TONS	12-MONTH ROLLING BASIS	0		
PA-0286	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural-gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW	Fire Pump Engine - 460 BHP	Diesel	0		Carbon Monoxide		0.5	G/HP-H		OTHER CASE-BY-CASE	OTHER	0.51	LB/H		0.03	T/YR	
PA-0309	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3)	2000 kW Emergency Generator	Ultra-low sulfur Diesel	0		Carbon Monoxide		0.6	GM/HP-HR		BACT-PSD		0.089	TONS	12-MONTH ROLLING BASIS	0		
PA-0311	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 2 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined-	Fire Pump Engine	diesel	0		Carbon Monoxide		1	G/HP-HR		BACT-PSD	NSPS	0.28	TPY	12-MOTH ROLLING BASIS	0		
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033-X014 - X020	331111	07/22/2014 ACT	STEEL MILL ADDING 2ND BAGHOUSE TO EAF, AUSTENITIZING FURNACE, TEMPERING FURNACE, VACUUM DEGASSER, PLASMA TORCHES, AND EMERGENCY GENERATORS	DIESEL FIRED EMERGENCY GENERATOR	DIESEL	800	HP	Carbon Monoxide		0.0055	LB/HP-H		BACT-PSD	NSPS , MACT	0			0		
TX-0799	PHILLIPS 66 PIPELINE LLC	TX	18295, PSDTX1466, GHGPSDTX139	424710	06/08/2016 ACT	This marine terminal receives, stores, and distributes various volatile organic liquids (VOLs) and refined petroleum products.	Fire pump engines	diesel	0		Carbon Monoxide	Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	0.0055	LB/HP-HR		BACT-PSD		0			0		
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	AL	413-0033-X014 - X020	331111	07/22/2014 ACT	STEEL MILL ADDING 2ND BAGHOUSE TO EAF, AUSTENITIZING FURNACE, TEMPERING FURNACE, VACUUM DEGASSER, PLASMA TORCHES, AND EMERGENCY GENERATORS	DIESEL FIRED EMERGENCY GENERATOR	DIESEL	800	HP	Carbon Monoxide		0.0055	LB/HP-H		BACT-PSD	NSPS , MACT	0			0		
AK-0082	EXXON MOBIL CORPORATION	AK	AQ1201CPT03	211111	01/23/2015 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY.	Emergency Camp Generators	Ultra Low Sulfur Diesel	2695	hp	Carbon Monoxide		2.6	GRAMS/HP-H		BACT-PSD		0			0		
CA-1212	CITY OF PALMDALE	CA	SE 09-01	221112	10/18/2011 ACT	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	EMERGENCY IC ENGINE	DIESEL	2683	HP	Carbon Monoxide		3.5	G/KW-H		BACT-PSD		2.6	G/HP-H		0		
FL-0332	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	PSD-FL-416, 0550063-001-AC	221119	09/23/2011 ACT	THIS PROJECT INVOLVES THE CONSTRUCTION OF A SUGARCANE AND SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY WITH A MAXIMUM ANNUAL ETHANOL (C2H5OH) PRODUCTION RATE OF 36 MILLION GALLONS PER YEAR (MGPY). THE CANE (I.E. THE SUGARCANE AND SORGHUM) WILL BE GROWN ON NEARBY FARMLAND. THE JUICE WILL BE SQUEEZED FROM THE FEEDSTOCK	600 HP Emergency Equipment	Ultra-Low Sulfur Oil	0		Carbon Monoxide	See Pollutant Notes.	2.6	G/HP-H		BACT-PSD	NSPS	0			0		
IN-0158	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Carbon Monoxide	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	2.6	G/HP-H		BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IN-0158	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Carbon Monoxide	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	2.6	G/HP-H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Carbon Monoxide	GOOD COMBUSTION PRACTICES	2.6	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Carbon Monoxide	GOOD COMBUSTION PRACTICES	2.6	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
KY-0109	FRITZ WINTER NORTH AMERICA, LP	KY	V-16-022 R1	331511	10/24/2016 ACT	This facility consists of a gray iron foundry, casting, and machining operation that produces automotive parts in Simpson County, Kentucky. The facility comprises an approximately 95 acre site, consisting of scrap handling and preparation equipment, melt furnaces, sand and mineral storage, mixing and handling equipment, mold and core	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	Diesel	53.6	gal/hr	Carbon Monoxide	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures and verifies the use of operational and design	2.6	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT	BACT-PSD	OPERATING PERMIT , MACT	3.73	G/HP-HR (EU74)	REQ. MANUFACTURER'S CERT	0		
LA-0254	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	1827 MW POWER PLANT (PSD PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Carbon Monoxide	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	2.6	G/HP-H	ANNUAL AVERAGE	BACT-PSD	OPERATING PERMIT	0			2.6	G/HP-H	ANNUAL AVERAGE
LA-0313	ENTERGY LOUISIANA, LLC	LA	PSD-LA-804	221112	08/31/2016 ACT	The St. Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.	SCPS Emergency Diesel Generator 1	Diesel	2584	HP	Carbon Monoxide	Compliance with NESHAP 40 CFR 63 Subpart ZZZZ and NSPS 40 CFR 60 Subpart IIII, and good combustion practices (use of ultra-low sulfur diesel fuel).	14.81	LB/H	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	3.7	T/YR	ANNUAL MAXIMUM	2.6	G/BHP-HR	
MD-0042	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	CPCN CASE NO. 9327	221119	04/08/2014 ACT	1000 MEGAWATT COMBINED CYCLE NATURAL GAS-FIRED POWER PLANTFACILITY-WIDE PM10 EMISSION LIMIT = 278 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT = 272 TONS/YR FACILITY-WIDE SAM EMISSION LIMIT = 96 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 3,498,026 TONS/YR	EMERGENCY GENERATOR 1	ULTRA LOW SULFU DIESEL	2250	KW	Carbon Monoxide	USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR	2.6	G/HP-H		BACT-PSD	NSPS	3.49	G/KW-H		0		
MD-0044	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1550	HP	Carbon Monoxide	GOOD COMBUSTION PRACTICES AND DESIGNED TO MEET EMISSION LIMIT	2.6	G/HP-H		BACT-PSD		3.49	G/KW-H		0		
MI-0406	LS POWER DEVELOPMENT LLC	MI	51-13	221112	11/01/2013 ACT	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	FG-EMGEN7-8, Two (2) 1,000kW diesel-fueled emergency reciprocating internal	Diesel	1000	kW	Carbon Monoxide	Good combustion practices.	2.6	G/B-HP-H	TEST PROTOCOL; EACH UNIT	BACT-PSD	NSPS , SIP	0			0		
OH-0368	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Emergency Generator (P009)	Diesel fuel	5000	HP	Carbon Monoxide	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	28.8	LB/H		BACT-PSD	NSPS	1.4	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/B-HP-H	SEE NOTES
OH-0372	OREGON ENERGY CENTER	OH	P0121049	221112	09/27/2017 ACT	Combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Carbon Monoxide	State-of-the-art combustion design	8.8	LB/H		BACT-PSD	NSPS	2.2	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/B-HP-H	SEE NOTES
OH-0374	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Carbon Monoxide	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the	12.69	LB/H		BACT-PSD	NSPS	0.63	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Carbon Monoxide	Good combustion design	12.64	LB/H		BACT-PSD	NSPS	0.63	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/BHP-H	SEE NOTES
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Carbon Monoxide	Good combustion design	4.01	LB/H		BACT-PSD	NSPS	0.2	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/BHP-H	SEE NOTES
OH-0376	IRONUNITS LLC - TOLEDO HBI	OH	P0123395	331111	02/09/2018 ACT	Hot briquetted iron production	Emergency diesel-fired generator (P007)	Diesel fuel	2682	HP	Carbon Monoxide	Comply with NSPS 40 CFR 60 Subpart IIII	15.4	LB/H		BACT-PSD	NSPS	3.86	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Carbon Monoxide	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	19.25	LB/H		BACT-PSD	NSPS	0.96	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Carbon Monoxide	certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	7.7	LB/H		BACT-PSD	NSPS	0.39	T/YR	PER ROLLING 12 MONTH PERIOD	2.6	G/BHP-H	SEE NOTES
PR-0009	ENERGY ANSWERS ARECIBO, LLC	PR	R2-PSD 1	221119	04/10/2014 ACT	Energy Answers Arecibo is a new resource recovery facility capable of producing up to 77 megawatts (MW) of electrical power while combusting municipal solid waste, as the primary fuel.	Emergency Diesel Generator	ULSD Fuel oil # 2	0		Carbon Monoxide		2.6	G/BHP-H		BACT-PSD		3.86	LB/H		0		
VA-0328	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Emergency Diesel GEN	Ultra Low Sulfur Diesel	500	H/YR	Carbon Monoxide	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	2.6	G/HP H		BACT-PSD	SIP , NSPS	5.2	T/YR	12 MO ROLLING TOTAL	0		
*VA-0332	CHICKAHOMINY POWER LLC	VA	52610-1	221112	06/24/2019 ACT	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/hr natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Emegency Fire Water Pump	Ultra Low Sulfur Diesel	500	HR/YR	Carbon Monoxide	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	2.6	G/HP-HR		BACT-PSD	NSPS , SIP	0.6	T/YR		0		
WV-0025	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Emergency Generator	Diesel	2015.7	HP	Carbon Monoxide		0			BACT-PSD	NSPS	0			2.6	G/HP-HR	
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	Diesel	2922	HP	Carbon Monoxide	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			2.6	G/B-HP-H	

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Tunnel Furnace Emergency Generator (EP 08-06)	Diesel	2937	HP	Carbon Monoxide	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			2.6	G/B-HP-H	
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Caster B Emergency Generator (EP 08-07)	Diesel	2937	HP	Carbon Monoxide	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			2.6	G/B-HP-H	
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Air Separation Unit Emergency Generator (EP 08-08)	Diesel	700	HP	Carbon Monoxide	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			2.6	G/B-HP-H	
KY-0115	NUCOR STEEL GALLATIN, LLC	KY	V-20-015	331111	04/19/2021 ACT	Nucor Steel Gallatin (NSG) is a steel recycling mini-mill located in Ghent, KY, along the Ohio River, and northeast of Louisville, KY. The NSG mill recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes are brought to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux are charged to the EAF and melted by	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	Carbon Monoxide	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan	0			BACT-PSD	NSPS , NESHAP	0			2.6	G/B-HP-H	
*LA-0312	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	horsepower	Carbon Monoxide	Compliance with NSPS Subpart IIII	0.9	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
*LA-0312	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	Diesel	1474	horsepower	Carbon Monoxide	Compliance with NSPS Subpart IIII	0.51	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
AR-0140	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Carbon Monoxide	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	3.5	G/KW-H		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Carbon Monoxide	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	3.5	G/KW-HR		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Carbon Monoxide	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	3.5	G/KW-HR		BACT-PSD		0			0		
FL-0332	HIGHLANDS ENVIROFUELS (HEF), LLC	FL	PSD-FL-416, 0550063-001-AC	221119	09/23/2011 ACT	THIS PROJECT INVOLVES THE CONSTRUCTION OF A SUGARCANE AND SWEET SORGHUM-TO-ETHANOL ADVANCED BIOREFINERY WITH A MAXIMUM ANNUAL ETHANOL (C2H5OH) PRODUCTION RATE OF 36 MILLION GALLONS PER YEAR (MGPY). THE CANE (I.E. THE SUGARCANE AND SORGHUM) WILL BE GROWN ON NEARBY FARMLAND. THE JUICE WILL BE SQUEEZED FROM THE FEEDSTOCK	2000 KW Emergency Equipment		0		Carbon Monoxide	See Pollutant Notes.	3.5	G/KW-H		BACT-PSD	NSPS	0			0		
FL-0346	FLORIDA POWER & LIGHT	FL	0110037-011-AC	221112	04/22/2014 ACT	Large natural gas- and oil-fired power facility, consisting of four combined cycle units, and many combustion turbines. Small peaking units being replaced with larger combustion turbines.	Emergency fire pump engine (300 HP)	USLD	29	MMBTU/H	Carbon Monoxide	Good combustion practice.	3.5	GRAM PER KW-HR		BACT-PSD	NSPS , NESHAP	0			0		
FL-0356	FLORIDA POWER & LIGHT	FL	0930117-001-AC	221112	03/09/2016 ACT	Fossil-fueled power plant, consisting of a 3-on-1 combined cycle unit and auxiliary equipment. The combined cycle unit consists of three GE 7HA.02 turbines, each with nominal generating capacity of 350 MW. The total generating capacity for the combined cycle unit is 1,600 MW.	Three 3300-kW ULSD emergency generators	ULSD	0		Carbon Monoxide	Use of clean engine	3.5	G / KW-HR		BACT-PSD	NSPS	0			0		
*FL-0363	FLORIDA POWER AND LIGHT COMPANY	FL	0110037-017-AC	221112	12/04/2017 ACT	1200 megawatt 2-on-1 combined cycle facility, natural gas-fired, with limited ULSD use. GE 7HA turbines	Two 3300 kW emergency generators	ULSD	0		Carbon Monoxide	Certified engine	3.5	GRAMS PER KWH		BACT-PSD	NSPS	0			0		
IA-0105	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Carbon Monoxide	good combustion practices	3.5	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		3.86	TONS/YR	ROLLING 12 MONTH TOTAL	0		
IA-0106	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Carbon Monoxide	good combustion practices	3.5	G/KW-H	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	SIP	2.52	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	0		
IL-0114	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Emergency Generator	distillate fuel oil	3755	HP	Carbon Monoxide	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3.5	G/KW-H		BACT-PSD		0			0		
IL-0130	JACKSON GENERATION, LLC	IL	17040013	221112	12/31/2018 ACT	The proposed facility is designed to generate 1800MW power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would only burn natural gas. Other units include an auxiliary boiler, fuel heater, emergency engines, natural gas piping and components, circuit breakers and roadways	Emergency Engine	Ultra-Low Sulfur Diesel	1500	kW	Carbon Monoxide		3.5	G/KW-HR		BACT-PSD	NSPS	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency generator EU-6006	Diesel	2800	HP	Carbon Monoxide	Tier II diesel engine	3.5	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency fire pump EU-6008	Diesel	750	HP	Carbon Monoxide	Engine that complies with Table 4 to Subpart IIII of Part 60	3.5	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Large Emergency Engines (>50kW)	Diesel Fuel	5364	HP	Carbon Monoxide	Good Combustion and Operating Practices.	3.5	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
MI-0421	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	Diesel	500	H/YR	Carbon Monoxide	Good design and combustion practices.	3.5	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	12.35	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	0		
MI-0421	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Dieself fire pump engine (EUFIREPUMP in FGRICE)	Diesel	500	H/YR	Carbon Monoxide	Good design and combustion practices.	3.5	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	3.09	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MI-0423	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUEMENGINE (Diesel fuel emergency engine)	Diesel Fuel	22.68	MMBTU/H	Carbon Monoxide	Good combustion practices and meeting NSPS Subpart IIII requirements.	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY AVG TIME	BACT-PSD	NSPS , SIP	0			0		
MI-0425	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	Diesel	500	H/YR	Carbon Monoxide	Good design and combustion practices.	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	NSPS , SIP	11.6	LB/H	TEST PROTOCOL SHALL SPECIFY	0		
MI-0425	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	Diesel	500	H/YR	Carbon Monoxide	Good design and combustion practices.	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	NSPS , SIP	3.9	LB/H	TEST PROTOCOL SHALL SPECIFY	0		
MI-0425	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUFIREPUMP in FGRICE (Diesel fire pump engine)	Diesel	500	H/YR	Carbon Monoxide	Good design and combustion practices.	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	BACT-PSD	NSPS , SIP	3.09	LB/H	TEST PROTOCOL SHALL SPECIFY	0		
MI-0433	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (North Plant): Emergency Engine	Diesel	1341	HP	Carbon Monoxide	Good combustion practices and meeting NSPS Subpart IIII requirements.	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
MI-0433	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (South Plant): Emergency Engine	Diesel	1341	HP	Carbon Monoxide	Good combustion practices and meeting NSPS IIII requirements.	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
MI-0435	DTE ELECTRIC COMPANY	MI	19-18	221112	07/16/2018 ACT	Natural gas combined-cycle power plant	EUEMENGINE: Emergency engine	Diesel	2	MW	Carbon Monoxide	State of the art combustion design.	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*MI-0441	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Carbon Monoxide	Good combustion practices and will be NSPS compliant.	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*MI-0441	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Carbon Monoxide	Good combustion practices and will be NSPS compliant.	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*MI-0445	INDECK NILES, LLC	MI	75-16B	221112	11/26/2019 ACT	Natural gas combined cycle power plant	EUEMENGINE (diesel fuel emergency engine)	diesel fuel	22.68	MMBTU/H	Carbon Monoxide	Good Combustion Practices and meeting NSPS Subpart IIII requirements	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
*PA-0313	FIRST QUALITY TISSUE, LLC	PA	18-00030C	322291	07/27/2017 ACT	This plan approval is issued for the construction of 376.3 ton per day paper towel and tissue machine comprised of a wet-end section, a wet-end dryer section, a dry-end dryer section and a dry-end section. The wet-end dryer shall incorporate a through-airdryer equipped with a 105 million Btu per hour, natural gas/propane-fired in-line, low NOx, duct burner. The dry-end dryer shall	Emergency Generator	Diesel	2500	bhp	Carbon Monoxide		3.5	G	KW-HR			3.6	TONS	12 CONSECUTIVE MONTH PERIOD	0		
SC-0113	PYRAMAX CERAMICS, LLC	SC	0160-0023	327992	02/08/2012 ACT	PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS.	FIRE PUMP	DIESEL	500	HP	Carbon Monoxide	ENGINES CERTIFIED TO MEET NSPS, SUBPART IIII. HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR FOR MAINTENANCE AND TESTING.	3.5	GR/KW-H		BACT-PSD	NSPS	0			0		
SC-0113	PYRAMAX CERAMICS, LLC	SC	0160-0023	327992	02/08/2012 ACT	PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS.	EMERGENCY GENERATORS 1 THRU 8	DIESEL	757	HP	Carbon Monoxide	ENGINES MUST BE CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	3.5	GR/KW-H		BACT-PSD	NSPS	0			0		
VA-0321	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52404	221112	03/12/2013 ACT	New, combined-cycle, natural gas-fired, electrical power generating facility.	Emergency diesel generator- 2200 kW	ultra low sulfur diesel	500	hrs/yr	Carbon Monoxide	good combustion practices	3.5	G/KW-HR		BACT-PSD	NSPS , SIP	4.3	TONS/YR	12 MO ROLLING AVG	0		
VA-0325	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 1300 MW combined cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	DIESEL FUEL	0		Carbon Monoxide	Good Combustion Practices/Maintenance	3.5	G/KW	PER HR	N/A		5.8	T/YR	12 MO ROLLING TOTAL	0		
IL-0129	CPV THREE RIVERS, LLC	IL	16060032	221112	07/30/2018 ACT	The proposed facility is designed to generate baseload power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would burn natural gas and ultra-low sulfur diesel (ULSD) as a backup fuel. Other units include an auxiliary boiler, fuel heater, engines, natural gas piping and	Emergency Engines	Ultra-low sulfur diesel	0		Carbon Monoxide		0			BACT-PSD	NSPS	0			0		
OH-0352	ARCADIS, US, INC.	OH	P0110840	221112	06/18/2013 ACT	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency generator	diesel	2250	KW	Carbon Monoxide	Purchased certified to the standards in NSPS Subpart IIII	17.35	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	4.34	T/YR	PER ROLLING 12-MONTHS	0		SEE NOTES
OH-0360	CARROLL COUNTY ENERGY	OH	P0113762	221112	11/05/2013 ACT	Natural gas fired combined cycle gas turbine electric generating station of nominal capacity of 742 MW	Emergency generator (P003)	diesel	1112	KW	Carbon Monoxide	Purchased certified to the standards in NSPS Subpart IIII	8.57	LB/H		BACT-PSD	NSPS	2.14	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	P0117655	221112	08/25/2015 ACT	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2346	HP	Carbon Monoxide	State-of-the-art combustion design	13.5	LB/H		BACT-PSD	NSPS	3.37	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0367	SOUTH FIELD ENERGY LLC	OH	P0119495	221112	09/23/2016 ACT	1150 MW combined-cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2947	HP	Carbon Monoxide	State-of-the-art combustion design	16.96	LB/H		BACT-PSD	NSPS	4.24	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0370	TRUMBULL ENERGY CENTER	OH	P0122331	221112	09/07/2017 ACT	940 MW combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Carbon Monoxide	State-of-the-art combustion design	8.8	LB/H		BACT-PSD	NSPS	2.2	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
AR-0163	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Carbon Monoxide	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	3.5	G/KW-HR		BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
MI-0441	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Carbon Monoxide	Good combustion practices and will be NSPS compliant.	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
MI-0441	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Carbon Monoxide	Good combustion practices and will be NSPS compliant.	3.5	G/KW-H	HOURLY	BACT-PSD	NSPS , SIP	0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Carbon Monoxide	GOOD COMBUSTION PRACTICES	2.61	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	DIESEL-FIRED EMERGENCY GENERATOR	NO. 2 FUEL OIL	4690	B-HP	Carbon Monoxide	GOOD COMBUSTION PRACTICES	2.61	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Carbon Monoxide	GOOD COMBUSTION PRACTICES	2.61	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	EMERGENCY GENERATORS (EU014A AND EU-014B)	DISTILLATE OIL	3600	HP EACH	Carbon Monoxide	GOOD COMBUSTION PRACTICES	2.61	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		500	H/YR EACH		0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD		0			0		
OH-0363		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Emergency generator (P002)	Diesel fuel	1100	KW	Carbon Monoxide	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	8.49	LB/H		BACT-PSD	NSPS	2.12	T/YR	PER ROLLING 12 MONTH PERIOD	2.61	G/B-HP-H	
PA-0310	CPV FAIRVIEW, LLC	PA	11-00536A	221112	09/02/2016 ACT	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric	Emergency Generator Engines	ULSD	0		Carbon Monoxide		2.61	G/BHP-HR		BACT-PSD	NSPS	0			0		
PA-0310	CPV FAIRVIEW, LLC	PA	11-00536A	221112	09/02/2016 ACT	This plan approval authorizes CPV Fairview, LLC to construct and temporarily operate the Fairview Energy Center. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include: A combined cycle electric generating unit consisting of two (2) General Electric	Emergency Fire Pump Engine	ULSD	0		Carbon Monoxide		2.61	G/BHP-HR		BACT-PSD	NSPS	0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD	NSPS , NESHAP	0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Carbon Monoxide	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	2.61	G/HP-HR		BACT-PSD		0			0		
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 1	Diesel	5364	HP	Carbon Monoxide	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	30.86	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	1.54	T/YR	ANNUAL MAXIMUM	2.625	G/BHP-H	
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 2	Diesel	5364	HP	Carbon Monoxide	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	30.86	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	1.54	T/YR	ANNUAL MAXIMUM	2.625	G/BHP-H	
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 1	Diesel	751	HP	Carbon Monoxide	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.32	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.22	T/YR	ANNUAL MAXIMUM	2.625	G/BHP-H	

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 2	Diesel	751	HP	Carbon Monoxide	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	4.32	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.22	T/YR	ANNUAL MAXIMUM	2.625	G/BHP-H	
TX-0799	PHILLIPS 66 PIPELINE LLC	TX	18295, PSDTX1466, GHGPSDTX139	424710	06/08/2016 ACT	This marine terminal receives, stores, and distributes various volatile organic liquids (VOLs) and refined petroleum products.	EMERGENCY ENGINES	diesel	0		Carbon Monoxide	Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	0.0068	LB/HP-HR		BACT-PSD		0			0		
AK-0084	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 12 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Black Start and Emergency Internal Cumbustion Engines	Diesel	1500	kWe	Carbon Monoxide	Good Combustion Practices	4.38	G/KW-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Firewater Pumps	Diesel Fuel	634	kW	Carbon Monoxide	Good Combustion and Operating Practices.	3.7	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
FL-0328	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The	Emergency Engine	Diesel	0		Carbon Monoxide	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	0.09	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The	Emergency Fire Pump Engine	Diesel	0		Carbon Monoxide	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	0.005	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - Development Driller 1	Diesel	2229	hp	Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure	0.37	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - C.R. Luigs	diesel	2064	hp	Carbon Monoxide	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure	0.34	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Emergency Diesel Engine	Diesel	3300	hp	Carbon Monoxide	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
IN-0166	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Carbon Monoxide	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0			BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Carbon Monoxide	GOOD COMBUSTION PRACTICES AND LIMITED HOURS OF NON-EMERGENCY OPERATION	0			BACT-PSD		0			0		
LA-0288	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		2682	HP	Carbon Monoxide	Comply with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel	15.43	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.77	TPY	ANNUAL MAXIMUM	0		
LA-0296	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325211	05/23/2014 ACT	The Low Density Polyethylene (LDPE) Unit will produce LDPE by the high pressure polymerization of ethylene.	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, &	Diesel	2682	HP	Carbon Monoxide	Compliance with 40 CFR 60 Subpart IIII, operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize	15.43	LB/HR	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.77	TPY	ANNUAL MAXIMUM	0		
LA-0305	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Diesel Engines (Emergency)	Diesel	4023	hp	Carbon Monoxide	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0309	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	06/04/2015 ACT	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Emergency Generator Engines	Diesel	2922	hp (each)	Carbon Monoxide	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
LA-0316	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	emergency generator engines (6 units)	diesel	3353	hp	Carbon Monoxide	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0317	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Emergency Generator Engines (4 units)	Diesel	0		Carbon Monoxide	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0317	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Firewater pump Engines (4 units)	diesel	896	hp (each)	Carbon Monoxide	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0323	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 3 Engine	Diesel Fuel	600	hp	Carbon Monoxide	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0323	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 4 Engine	Diesel Fuel	600	hp	Carbon Monoxide	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
*LA-0350	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-744(M2)	331210	03/28/2018 ACT	A steel tube manufacturing facility from scrap metal	emergency generators (3 units) EQT0039, EQT0040, EQT0041		0		Carbon Monoxide	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
*LA-0364	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Generator Diesel Engines	Diesel Fuel	550	hp	Carbon Monoxide	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize	0			BACT-PSD	NSPS , NESHAP	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*LA-0364	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Fire Water Pumps	Diesel Fuel	550	hp	Carbon Monoxide	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize	0			BACT-PSD	NSPS , NESHAP	0			0		
*MA-0043	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	NE-15-018	611310	06/21/2017 ACT	MIT proposes to construct and operate two new 22 megawatt (MW) combined heat and power (CHP) combustion turbines/heat recovery steam generators and a new cold start engine at its existing Central Utility Plant.	Cold Start Engine	ULSD	19.04	MMBTU/HR	Carbon Monoxide		2.2	LB/HR	1 HR BLOCK AVG	OTHER CASE-BY-CASE	NSPS , NESHAP , SIP , OPERATING PERMIT	0.33	TONS/C12MP	CONSECUTIVE TWELVE MONTH PERIOD	0		
NJ-0079	CPV SHORE, LLC	NJ	18940 - BOP110003	221112	07/25/2012 ACT	Woodbridge Energy Center (WEC), proposed at Riverside Drive in Woodbridge Township (Middlesex County), New Jersey, 07095, would be a new, highly efficient, 700 MW combined-cycle power generating facility. WEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,307 MMBtu/hr, that will utilize pipeline natural gas only. Heat	Emergency Generator	Ultra Low Sulfur distillate Diesel	100	H/YR	Carbon Monoxide	Use of ULSD oil	1.99	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
NJ-0080	HESS NEWARK ENERGY CENTER, LLC	NJ	08857/BOP110001	221112	11/01/2012 ACT	combined cycle electric generating facility HESS Newark Energy Center (Hess-NEC), proposed at City of Newark (Essex County), New Jersey, would be a new, highly efficient, 655 MW combined-cycle power generating facility. Hess-NEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,320	Emergency Generator	ULSD	200	H/YR	Carbon Monoxide		11.56	LB/H		BACT-PSD	OPERATING PERMIT	0			0		
NJ-0084	PSEG FOSSIL LLC	NJ	18068/BOP150001	221112	03/10/2016 ACT	PSEG Fossil LLC Sewaren Generating Station (Sewaren or Facility) is located at 751 Cliff Road, Sewaren, New Jersey 07077-1439, Middlesex County, New Jersey. This â€œProjectâ€ to be built at Sewaren would be a 1-on-1 (1 combustion turbine and a single steam turbine) combined-cycle electric generating unit including its ancillary equipment. The electric output of the	Diesel Fired Emergency Generator	ULSD	44	H/YR	Carbon Monoxide	use of ultra low sulfur diesel oil a clean burning fuel	3.5	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
NY-0104	CPV VALLEY LLC	NY	3-335600136/00001	221112	08/01/2013 ACT	CPV Valley Energy Center is a 680 MW combined cycle electric generating facility located in Middletown, NY. The combustion turbines are rated at 2,234 MMBTU/H firing natural gas and 2,145 MMBTU/H firing diesel fuel. The duct burners are rated for 500 MMBTU/H firing natural gas. In addition to the turbines their emission limits for the auxiliary boiler (73.5 MMBTU/H),	Fire pump	ultra low sulfur diesel	0		Carbon Monoxide	Good combustion practice.	0.75	LB/MMBTU	1 H	BACT-PSD		0			0		
OK-0154	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	2008-302-C(M-1)PSD	221112	07/02/2013 ACT	WFEC operates the Mooreland Generating Station to generate wholesale electricity which is transmitted over WFECâ€™s system. The facility was originally constructed in 1963. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma and part of New Mexico. The Mooreland Generating Station currently consists of three high-pressure boilers	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	DIESEL	1341	HP	Carbon Monoxide	COMBUSTION CONTROL.	0.001	LB/HR		BACT-PSD		0			0		
TX-0876	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency generator	DIESEL	0		Carbon Monoxide	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency firewater pumps		0		Carbon Monoxide	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0888	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	an initial HAP, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers, flares, cooling towers, wastewater treatment plant, loadout facilities, miscellaneous auxiliary support facilities, and associated MSS.	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	Ultra-low Sulfur Diesel	0		Carbon Monoxide	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	0			0		
*TX-0904		TX	156571, PSDTX1564, GHGPSDTX195		09/09/2020 ACT	new polyethylene plant that will produce both LLDPE and HDPE	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Carbon Monoxide	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		0			0		
*TX-0905	DIAMOND GREEN DIESEL	TX	160299, PSDTX1576, GHGPSDTX200	325998	09/16/2020 ACT	a new renewable diesel fuels plant that will produce renewable diesel fuel and other renewable fuels.	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Carbon Monoxide	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		0			0		
WY-0070	BLACK HILLS POWER, INC.	WY	CT-12636	221112	08/28/2012 ACT	A nominal 220 megawatt (MW) gross electrical facility. The station is to consist of five (5) 40 MW GE LM6000 combustion turbine generators with two (2) of the turbines operating in combined cycle mode for an additional 20 MW in generation.	Diesel Emergency Generator (EP15)	Ultra Low Sulfur Diesel	839	hp	Carbon Monoxide	EPA Tier 2 rated	0			BACT-PSD	NSPS	0			0		
*TX-0933	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	Emergency Generators	Ultra-low sulfur diesel (no more than 15	0		Carbon Monoxide	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
PA-0278	MOXIE ENERGY LLC	PA	08Â-00045A	221112	10/10/2012 ACT		Emergency Generator	Diesel	0		Volatile Organic Compounds (VOC)		0.01	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.03	LB/H		0		
PA-0286	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW	EMERGENCY GENERATOR-ENGINE	Diesel	0		Volatile Organic Compounds (VOC)		0.01	GM/B-HP-H	EXPRESSED AS THC	OTHER CASE-BY-CASE	OTHER	0.03	LB/H		0.01	T/YR	
PA-0311	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined-	Emergency Generator		0		Volatile Organic Compounds (VOC)		0.02	G/HP-HR		LAER	NSPS	0.002	TPY	12-MONTH ROLLING BASIS	0		
*LA-0312	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	Diesel	1474	horsepower	Volatile Organic Compounds (VOC)	Compliance with NSPS Subpart IIII	0.04	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
TX-0872	MAGELLAN PROCESSING, L.P.	TX	118270 PSDTX1398M1 GHGPSDTX62	324110	10/31/2019 ACT	The site can process upwards of 100,000 bbls of condensate daily via two trains. The site uses a series of separation towers, collectively known as a condensate splitter. Condensate is received and refined into light and heavy naphtha, kerosene/distillate, residuum and liquified petroleum gas. The refined materials are either stored into storage tanks or loaded into either a truck or marine	Emergency Generators	ultra low sulfur diesel	0		Volatile Organic Compounds (VOC)	Limiting duration and frequency of generator use to 100 hr/yr. Good combustion practices will be used to reduce VOC including maintaining proper air-to-fuel ratio.	0.12	G/KW HR		BACT-PSD	NSPS , MACT	0			0		
PA-0278	MOXIE ENERGY LLC	PA	08Â-00045A	221112	10/10/2012 ACT		Fire Pump	Diesel	0		Volatile Organic Compounds (VOC)		0.1	G/B-HP-H		OTHER CASE-BY-CASE	OTHER	0.1	LB/H		0		
TX-0879	MOTIVA ENTERPRISES LLC	TX	7238 AND PSDTX1548	424710	02/19/2020 ACT	This application includes construction of two storage tanks at the 7th Street Tank Farm, six storage tanks at the Port Arthur Terminal, and the refurbishment and reauthorization of Berth 1 at Texaco Island. A VCU will be installed to control Berth 1 loading operations. In addition, loading of benzene and p-xylene is being authorized for Berths 1, 2, 6, and 7. Loading of heavy and light pygas is	Emergency Firewater Engine	Ultra-low sulfur diesel	0		Volatile Organic Compounds (VOC)	Meeting the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight). Limited to 100 hrs/yr of non-emergency operation. Have a non-	0.1	G/HP HR		BACT-PSD	NSPS , MACT	0			0		
*LA-0312	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	horsepower	Volatile Organic Compounds (VOC)	Compliance with NNSPS Subpart IIII	0.13	LB/HR		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
PA-0286	MOXIE ENERGY LLC	PA	41-00084A	221112	01/31/2013 ACT	This plan approval is for the construction of two natural gas-fired combined cycle powerblocks where each powerblock consists of a combustion turbine and heat recovery steam generator with duct burner. The two powerblocks constructed pursuant to this plan approval will be either the two powerblocks rated 472 megawatts (MW) (P101 and P102) or the powerblocks rated 458 MW	Fire Pump Engine - 460 BHP	Diesel	0		Volatile Organic Compounds (VOC)		0.1	G/HP-H		OTHER CASE-BY-CASE	OTHER	0.1	LB/H		0.01	T/YR	
*VA-0332	CHICKAHOMINY POWER LLC	VA	52610-1	221112	06/24/2019 ACT	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/hr natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Emegency Fire Water Pump	Ultra Low Sulfur Diesel	500	HR/YR	Volatile Organic Compounds (VOC)	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	0.11	G/HP-HR		BACT-PSD	NSPS , SIP	0			0		
PA-0309	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3)	Fire pump engine	Ultra-low sulfur diesel	15	gal/hr	Volatile Organic Compounds (VOC)		0.12	GM/HP-HR		LAER		0.002	TONS	12-MONTH ROLLING BASIS	0		
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	0.141	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	0.141	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
PR-0009	ENERGY ANSWERS ARECIBO, LLC	PR	R2-PSD 1	221119	04/10/2014 ACT	Energy Answers Arecibo is a new resource recovery facility capable of producing up to 77 megawatts (MW) of electrical power while combusting municipal solid waste, as the primary fuel.	Emergency Diesel Generator	ULSD Fuel oil # 2	0		Volatile Organic Compounds (VOC)		0.15	G/B-HP-H		BACT-PSD		0.22	LB/H		0		
*AK-0085	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1524CPT01	486210	08/13/2020 ACT	The Gas Treatment Plant (GTP) is part of the integrated liquefied natural gas (LNG) project to bring natural gas from Alaskaâ€™s North Slope to international markets in the form of LNG, as well as for in-state deliveries in the form of natural gas. The GTP will take gas from the Prudhoe Bay Unit and the Point Thomson Unit and treat/process the gas, before it is sent 807 miles through a 42	One (1) Black Start Generator Engine	ULSD	186.6	gph	Volatile Organic Compounds (VOC)	Oxidation Catalyst, Good combustion practices, and limit operation to 500 hours per year.	0.18	G/HP-HR	3-HOUR AVERAGE	BACT-PSD	NSPS	0			0		
PA-0311	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two identical 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined-	Fire Pump Engine	diesel	0		Volatile Organic Compounds (VOC)		0.2	G/HP-HR		LAER	NSPS	0.006	TPY	12-MONTH ROLLING BASIS	0		
PA-0309	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3)	2000 kW Emergency Generator	Ultra-low sulfur Diesel	0		Volatile Organic Compounds (VOC)		0.22	GM/HP-HR		LAER		0.039	TONS	12-MONTH ROLLING BASIS	0		
LA-0292	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators No. 1 & No. 2	Diesel	1341	HP	Volatile Organic Compounds (VOC)	Good combustion practices consistent with the manufacturer's recommendations to maximize fuel efficiency and minimize emissions	0.83	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0.04	TPY	ANNUAL MAXIMUM	0.28	G/BHP-HR	
LA-0292	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators No. 1 & No. 2	Diesel	1341	HP	Volatile Organic Compounds (VOC)	Good combustion practices consistent with the manufacturer's recommendations to maximize fuel efficiency and minimize emissions	0.83	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0.04	TPY	ANNUAL MAXIMUM	0.28	G/BHP-HR	
IA-0105	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Volatile Organic Compounds (VOC)	good combustion practices	0.4	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		0.44	TONS/YR	ROLLING 12 MONTH TOTAL	0		
IL-0114	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Emergency Generator	distillate fuel oil	3755	HP	Volatile Organic Compounds (VOC)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.4	G/KW-H		BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	0.31	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IN-0179	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	DIESEL-FIRED EMERGENCY GENERATOR	NO. 2 FUEL OIL	4690	B-HP	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	0.31	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	0.31	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
AK-0082	EXXON MOBIL CORPORATION	AK	AQ1201CPT03	211111	01/23/2015 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY.	Emergency Camp Generators	Ultra Low Sulfur Diesel	2695	hp	Volatile Organic Compounds (VOC)		0.0007	LB/HP-H		BACT-PSD		0			0		
OK-0154	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	2008-302-C(M-1)PSD	221112	07/02/2013 ACT	WFEC operates the Mooreland Generating Station to generate wholesale electricity which is transmitted over WFEC's system. The facility was originally constructed in 1963. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma and part of New Mexico. The Mooreland Generating Station currently consists of three high-pressure boilers	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	DIESEL	1341	HP	Volatile Organic Compounds (VOC)	COMBUSTION CONTROL.	0.0007	LB/HP-HR		BACT-PSD	N/A	0			0		
TX-0799	PHILLIPS 66 PIPELINE LLC	TX	18295, PSDTX1466, GHGPSDTX139	424710	06/08/2016 ACT	This marine terminal receives, stores, and distributes various volatile organic liquids (VOLs) and refined petroleum products.	Fire pump engines	diesel	0		Volatile Organic Compounds (VOC)	Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	0.0007	LB/HP-HR		BACT-PSD		0			0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	EMERGENCY GENERATORS (EU014A AND EU-014B)	DISTILLATE OIL	3600	HP EACH	Volatile Organic Compounds (VOC)	GOOD COMBUSTION PRACTICES	0.35	G/HP-H EACH	3 HOUR AVERAGE	BACT-PSD		500	H/YR EACH		0		
*WI-0284		WI	18-JJW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Volatile Organic Compounds (VOC)	Good Combustion Practices	0.56	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
*WI-0286	SIO INTERNATIONAL	WI	18-JJW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Volatile Organic Compounds (VOC)	Good Combustion Practices	0.56	G/KWH		BACT-PSD	NSPS , NESHAP	0			0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Firewater Pumps	Diesel Fuel	634	kW	Volatile Organic Compounds (VOC)	Good combustion and operating practices.	0.44	G/HP-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0331	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Large Emergency Engines (>50kW)	Diesel Fuel	5364	HP	Volatile Organic Compounds (VOC)	Good combustion and operating practices.	0.79	G/KW-H		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
OH-0372	OREGON ENERGY CENTER	OH	P0121049	221112	09/27/2017 ACT	Combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Volatile Organic Compounds (VOC)	State-of-the-art combustion design	2	LB/H		BACT-PSD	NSPS	0.5	T/YR	PER ROLLING 12 MONTH PERIOD	0.59	G/B-HP-H	SEE NOTES
LA-0254	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	1827 MW POWER PLANT (PAE-I PROJECT). NATURAL GAS IS PRIMARY FUEL, NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Volatile Organic Compounds (VOC)	ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES	1	G/HP-H	ANNUAL AVERAGE	BACT-PSD	OPERATING PERMIT	0			1	G/HP-H	ANNUAL AVERAGE
TX-0799	PHILLIPS 66 PIPELINE LLC	TX	18295, PSDTX1466, GHGPSDTX139	424710	06/08/2016 ACT	This marine terminal receives, stores, and distributes various volatile organic liquids (VOLs) and refined petroleum products.	EMERGENCY ENGINES	diesel	0		Volatile Organic Compounds (VOC)	Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	0.0025	LB/HP-HR		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Volatile Organic Compounds (VOC)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	1.55	G/KW-HR		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Volatile Organic Compounds (VOC)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	1.55	G/KW-HR		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Volatile Organic Compounds (VOC)	Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII	1.9	G/KW-HR		BACT-PSD		0			0		
*PA-0313	FIRST QUALITY TISSUE, LLC	PA	18-00030C	322291	07/27/2017 ACT	This plant application is issued for the construction of 570.3 tons per day paper towel and tissue machine comprised of a wet-end section, a wet-end dryer section, a dry-end dryer section and a dry-end section. The wet-end dryer shall incorporate a through-airdryer equipped with a 105 million Btu per hour, natural gas/propane-fired in-line, low NOx, duct burner. The dry-end dryer shall	Emergency Generator	Diesel	2500	bhp	Volatile Organic Compounds (VOC)		3.5	G	KW-HR			1.67	TONS	12-CONSECUTIVE MONTH PERIOD	0		
IA-0106	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Volatile Organic Compounds (VOC)	good combustion practices	4	G/KW-H	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD		0.31	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency fire pump EU-6008	Diesel	750	HP	Volatile Organic Compounds (VOC)	Engine that complies with Table 4 to Subpart IIII of Part 60	4	G/KWH	COMBINED NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	0			0		
SC-0113	PYRAMAX CERAMICS, LLC	SC	0160-0023	327992	02/08/2012 ACT	PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS.	FIRE PUMP	DIESEL	500	HP	Volatile Organic Compounds (VOC)	CERTIFIED ENGINES THAT COMPLY WITH NSPS, SUBPART IIII. HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR FOR MAINTENANCE AND TESTING.	4	GR/KW-H		BACT-PSD	NSPS	0			0		
SC-0113	PYRAMAX CERAMICS, LLC	SC	0160-0023	327992	02/08/2012 ACT	PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS.	EMERGENCY GENERATORS 1 THRU 8	DIESEL	757	HP	Volatile Organic Compounds (VOC)	PURCHASE ENGINES CERTIFIED TO COMPLY WITH NSPS, SUBPART IIII.	4	GR/KW-H		BACT-PSD	NSPS	0			0		
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Volatile Organic Compounds (VOC)	Good combustion design	4.97	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	0.25	T/YR	NMHC+NOX. SEE NOTES.	3	G/BHP-H	NMHC+NOX. SEE NOTES.

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
KY-0109	FRITZ WINTER NORTH AMERICA, LP	KY	V-16-022 R1	331511	10/24/2016 ACT	This facility consists of a gray iron foundry, casting, and machining operation that produces automotive parts in Simpson County, Kentucky. The facility comprises an approximately 95 acre site, consisting of scrap handling and preparation equipment, melt furnaces, sand and mineral storage, mixing and handling equipment, mold and core	Emergency Generators #1, #2, & #3 (EU72, & EU74)	Diesel	53.6	gal/hr	Volatile Organic Compounds (VOC)	The permittee shall prepare and maintain for EU72, EU73, and EU74, within 90 days of startup, a good combustion and operation practices plan (GCOP) that defines, measures	4.77	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	BACT-PSD	MACT , OPERATING PERMIT	3.5	G/HP-HR (EU74)	REQ. MANUFACTURER'S CERT.	0		
OH-0374	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Volatile Organic Compounds (VOC)	Certified to the meet the emissions standards in 40 CFR 89.112 and 89.113 pursuant to 40 CFR 60.4205(b) and 60.4202(a)(2). Good combustion practices per the	23.21	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	1.16	T/YR	NMHC+NOX. SEE NOTES.	4.77	G/BHP-H	NMHC+NOX. SEE NOTES.
*IN-0317	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency generator EU-6006	Diesel	2800	HP	Volatile Organic Compounds (VOC)	Tier II diesel engine	6.4	G/KWH	TIER II NOX + NMHC LIMIT	BACT-PSD	NSPS , NESHAP	0			0		
SC-0159	MICHELIN NORTH AMERICA, INC.	SC	0200-0225-CA	326211	07/09/2012 ACT	THE FACILITY PRODUCES COMPONENTS FOR EARTHMOVER TIRES AND THEN IN TURN ASSEMBLES TIRES FROM THESE COMPONENTS.	EMERGENCY GENERATORS, GEN1, GEN2	DIESEL	1000	KW	Volatile Organic Compounds (VOC)	BACT HAS BEEN DETERMINED TO BE COMPLIANCE WITH NSPS, SUBPART IIII, 40 CFR60.4202 AND 40 CFR60.4205.	6.4	G/KW-H		BACT-PSD	NSPS	0			0		
VA-0325	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 1000 MW combined cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	DIESEL FUEL	0		Volatile Organic Compounds (VOC)	Good Combustion Practices/Maintenance	6.4	G/KW	PER HR	N/A		0			0		
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 1	Diesel	5364	HP	Volatile Organic Compounds (VOC)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	3.86	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.19	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 2	Diesel	5364	HP	Volatile Organic Compounds (VOC)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	3.86	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.19	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 1	Diesel	751	HP	Volatile Organic Compounds (VOC)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0.34	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.02	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
*LA-0315	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 2	Diesel	751	HP	Volatile Organic Compounds (VOC)	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0.34	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	0.02	T/YR	ANNUAL MAXIMUM	4.8	G/BHP-H	
MD-0044	DOMINION COVE POINT LNG, LP	MD	PSC CASE NO. 9318	221119	06/09/2014 ACT	LIQUIFIED NATURAL GAS PROCESSING FACILITY AND 130 MEGAWATT GENERATING STATIONFACILITY-WIDE PM10 EMISSION LIMIT = 124.2 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT= 124/2 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 2,030,988 TONS/YR FACILITY-WIDE FORMALDEHYDE EMISION LIMIT = 6.2 TONS/YR	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	1550	HP	Volatile Organic Compounds (VOC)	USE ONLY ULSD, GOOD COMBUSTION PRACTICES, AND DESIGNED TO ACHIEVE EMISSION LIMIT	4.8	G/HP-H	COMBINED NOX + NMHC	LAER	NSPS	6.4	G/KW-H	COMBINED NOX + NMHC	0		
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Volatile Organic Compounds (VOC)	Good combustion design	24.71	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	1.24	T/YR	NMHC+NOX. SEE NOTES.	4.8	G/BHP-H	NMHC+NOX. SEE NOTES.
OH-0377	HARRISON POWER	OH	P0122266	221112	04/19/2018 ACT	1000 MW natural gas-fired combined cycle combustion turbine plant	Emergency Diesel Generator (P003)	Diesel fuel	1860	HP	Volatile Organic Compounds (VOC)	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII	19.68	LB/H	NMHC+NOX. SEE NOTES.	BACT-PSD	NSPS	0.98	T/YR	NMHC+NOX. SEE NOTES.	4.8	G/BHP-H	NMHC+NOX. SEE NOTES.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Volatile Organic Compounds (VOC)	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	37.41	LB/H	SEE NOTES.	BACT-PSD	NSPS	1.87	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	4.8	G/BHP-H	SEE NOTES
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Volatile Organic Compounds (VOC)	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturerâ€™s operating manual	14.96	LB/H	SEE NOTES.	BACT-PSD	NSPS	0.75	T/YR	PER ROLLING 12 MONTH PERIOD. SEE NOTES.	4.8	G/BHP-H	SEE NOTES
AR-0140	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Volatile Organic Compounds (VOC)	GOOD OPERATING PRACTICES, LIMITED HOURS OF OPERATION, COMPLIANCE WITH NSPS SUBPART IIII	19	G/KW-H		BACT-PSD		0			0		
FL-0328	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The	Emergency Engine	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	0.03	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The	Emergency Fire Pump Engine	Diesel	0		Volatile Organic Compounds (VOC)	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	0.002	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - Development Driller 1	Diesel	2229	hp	Volatile Organic Compounds (VOC)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with	0.04	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - C.R. Luigs	diesel	2064	hp	Volatile Organic Compounds (VOC)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with	0.04	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0347	ANADARKO PETROLEUM CORPORATION	FL	OCS-EPA-R4015	211111	09/16/2014 ACT	The facility consists of a mobile offshore drilling unit using the Transocean Discoverer Spirit and associated support vessels. The drilling sites are located east of longitude 87.5, west of the Military Mission Line (86Â°41' west longitude), at least 100 miles from the Louisiana shoreline, and at least 125 miles from the Florida shoreline.	Emergency Diesel Engine	Diesel	3300	hp	Volatile Organic Compounds (VOC)	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure	0			BACT-PSD	OPERATING PERMIT	0			0		
IN-0158	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Volatile Organic Compounds (VOC)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	1.04	LB/H		BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		
IN-0158	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Volatile Organic Compounds (VOC)	COMBUSTION DESIGN CONTROLS AND USAGE LIMITS	1.04	LB/H	3 HOURS	BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
LA-0276	COLONIAL PIPELINE COMPANY	LA	PSD-LA-741(M4)	424710	12/15/2016 ACT	Pipeline Facility	Fire Pump Engines (2 units)	Diesel	700	hp	Volatile Organic Compounds (VOC)	Comply with standards of NSPS Subpart IIII	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0288	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		2682	HP	Volatile Organic Compounds (VOC)	Comply with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion	0.85	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0.04	TPY	ANNUAL MAXIMUM	0		
LA-0296	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325211	05/23/2014 ACT	The Low Density Polyethylene (LDPE) Unit will produce LDPE by the high pressure polymerization of ethylene.	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, &	Diesel	2682	HP	Volatile Organic Compounds (VOC)	Compliance with 40 CFR 60 Subpart IIII, operating the engine in accordance with the engine manufacturer's instructions and/or written procedures (consistent with safe operation) designed	0.85	LB/HR	HOURLY MAXIMUM	BACT-PSD	OPERATING PERMIT	0.04	TPY	ANNUAL MAXIMUM	0		
LA-0309	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	06/04/2015 ACT	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Emergency Generator Engines	Diesel	2922	hp (each)	Volatile Organic Compounds (VOC)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
LA-0313	ENTERGY LOUISIANA, LLC	LA	PSD-LA-804	221112	08/31/2016 ACT	The St. Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.	SCPS Emergency Diesel Generator 1	Diesel	2584	HP	Volatile Organic Compounds (VOC)	Good combustion practices	27.34	LB/H	HOURLY MAXIMUM	BACT-PSD	NSPS , OPERATING PERMIT	6.84	T/YR	ANNUAL MAXIMUM	0		
LA-0316	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	emergency generator engines (6 units)	diesel	3353	hp	Volatile Organic Compounds (VOC)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
*LA-0350	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-744(M2)	331210	03/28/2018 ACT	A steel tube manufacturing facility from scrap metal	emergency generators (3 units) EQT0039, EQT0040, EQT0041		0		Volatile Organic Compounds (VOC)	Comply with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
*LA-0364	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Generator Diesel Engines	Diesel Fuel	550	hp	Volatile Organic Compounds (VOC)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize	0			BACT-PSD	NSPS , NESHAP	0			0		
*LA-0364	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Fire Water Pumps	Diesel Fuel	550	hp	Volatile Organic Compounds (VOC)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize	0			BACT-PSD	NSPS , NESHAP	0			0		
*MA-0043	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	NE-15-018	611310	06/21/2017 ACT	MIT proposes to construct and operate two new 22 megawatt (MW) combined heat and power (CHP) combustion turbines/heat recovery steam generators and a new cold start engine at its existing Central Utility Plant.	Cold Start Engine	ULSD	19.04	MMBTU/HR	Volatile Organic Compounds (VOC)		0.85	LB/HR		OTHER CASE-BY-CASE	NSPS , NESHAP , SIP , OPERATING PERMIT	0.13	TONS/C12MP		0		
MI-0423	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUEMENGINE (Diesel fuel emergency engine)	Diesel Fuel	22.68	MMBTU/H	Volatile Organic Compounds (VOC)	Good combustion practices.	1.87	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	BACT-PSD		0			0		
MI-0433	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (North Plant): Emergency Engine	Diesel	1341	HP	Volatile Organic Compounds (VOC)	Good combustion practices.	0.86	LB/H	HOURLY	BACT-PSD		0			0		
MI-0433	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (South Plant): Emergency Engine	Diesel	1341	HP	Volatile Organic Compounds (VOC)	Good combustion practices	0.86	LB/H	HOURLY	BACT-PSD		0			0		
MI-0435	DTE ELECTRIC COMPANY	MI	19-18	221112	07/16/2018 ACT	Natural gas combined-cycle power plant	EUEMENGINE: Emergency engine	Diesel	2	MW	Volatile Organic Compounds (VOC)	State of the art combustion design.	1.89	LB/H	HOURLY	BACT-PSD	SIP	0			0		
*MI-0442	THOMAS TOWNSHIP ENERGY, LLC	MI	210-18	221112	08/21/2019 ACT	New power plant	FGEMENGINE	Diesel	1100	KW	Volatile Organic Compounds (VOC)		0.86	LB/H	HOURLY; EACH ENGINE	BACT-PSD		0			0		
NJ-0079	CPV SHORE, LLC	NJ	18940 - BOP110003	221112	07/25/2012 ACT	Woodbridge Energy Center (WEC), proposed at Riverside Drive in Woodbridge Township (Middlesex County), New Jersey, 07095, would be a new, highly efficient, 700 MW combined-cycle power generating facility. WEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,307 MMBtu/hr, that will utilize pipeline natural gas only. Heat	Emergency Generator	Ultra Low Sulfur distillate Diesel	100	H/YR	Volatile Organic Compounds (VOC)	Use of ULSD oil	0.49	LB/H		LAER	NSPS , OPERATING PERMIT	0			0		
NJ-0080	HESS NEWARK ENERGY CENTER, LLC	NJ	08857/BOP110001	221112	11/01/2012 ACT	combined cycle electric generating facility HESS Newark Energy Center (Hess-NEC), proposed at City of Newark (Essex County), New Jersey, would be a new, highly efficient, 655 MW combined-cycle power generating facility. Hess-NEC will consist of two General Electric (GE) combustion turbine generators (CTGs) with a heat input rate of 2,320	Emergency Generator	ULSD	200	H/YR	Volatile Organic Compounds (VOC)	use of ULSD, a low sulfur clean fuel	2.62	LB/H		LAER	OPERATING PERMIT	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
NJ-0084	PSEG FOSSIL LLC	NJ	18068/BOP150001	221112	03/10/2016 ACT	PSEG Fossil LLC Sewaren Generating Station (Sewaren 8 Facility) is located at 751 Cliff Road, Sewaren, New Jersey 07077-1439, Middlesex County, New Jersey. This â€œProjectâ€ to be built at Sewaren would be a 1-on-1 (1 combustion turbine and a single steam turbine) combined-cycle electric generating unit including its ancillary equipment. The electric output of the	Diesel Fired Emergency Generator	ULSD	44	H/YR	Volatile Organic Compounds (VOC)	use of ULSD a clean burning fuel, and limited hours of operation	1	LB/H		LAER	NSPS , OPERATING PERMIT	0			0		
NY-0104	CPV VALLEY LLC	NY	3-3356000136/00001	221112	08/01/2013 ACT	CPV Valley Energy Center is a 680 MW combined cycle electric generating facility located in Middletown, NY. The combustion turbines are rated at 2,234 MMBTU/H firing natural gas and 2,145 MMBTU/H firing diesel fuel. The duct burners are rated for 500 MMBTU/H firing natural gas. In addition to the turbines their emission limits for the auxiliary boiler (73.5 MMBTU/H),	Emergency generator	ultra low sulfur diesel	0		Volatile Organic Compounds (VOC)	Good combustion practice.	0.0331	LB/MMBTU	1 H	LAER		0			0		
NY-0104	CPV VALLEY LLC	NY	3-3356000136/00001	221112	08/01/2013 ACT	CPV Valley Energy Center is a 680 MW combined cycle electric generating facility located in Middletown, NY. The combustion turbines are rated at 2,234 MMBTU/H firing natural gas and 2,145 MMBTU/H firing diesel fuel. The duct burners are rated for 500 MMBTU/H firing natural gas. In addition to the turbines their emission limits for the auxiliary boiler (73.5 MMBTU/H),	Fire pump	ultra low sulfur diesel	0		Volatile Organic Compounds (VOC)	Good combustion practice.	0.3612	LB/MMBTU	1 H	LAER		0			0		
OH-0352	ARCADIS, US, INC.	OH	P0110840	221112	06/18/2013 ACT	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency generator	diesel	2250	KW	Volatile Organic Compounds (VOC)	Purchased certified to the standards in NSPS Subpart IIII	3.93	LB/H		BACT-PSD	NSPS , OPERATING PERMIT	0.98	T/YR	PER ROLLING 12-MONTHS	0		SEE NOTES
OH-0360	CARROLL COUNTY ENERGY	OH	P0113762	221112	11/05/2013 ACT	Natural gas fired combined cycle gas turbine electric generating station of nominal capacity of 742 MW	Emergency generator (P003)	diesel	1112	KW	Volatile Organic Compounds (VOC)	Purchased certified to the standards in NSPS Subpart IIII	1.93	LB/H		BACT-PSD	NSPS	0.48	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	P0117655	221112	08/25/2015 ACT	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2346	HP	Volatile Organic Compounds (VOC)		3.1	LB/H		BACT-PSD	NSPS	0.76	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0367	SOUTH FIELD ENERGY LLC	OH	P0119495	221112	09/23/2016 ACT	1150 MW combined-cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2947	HP	Volatile Organic Compounds (VOC)	State-of-the-art combustion design	3.84	LB/H		BACT-PSD	NSPS	0.96	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0368	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Emergency Generator (P009)	Diesel fuel	5000	HP	Volatile Organic Compounds (VOC)	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	1.6	LB/H		BACT-PSD	NSPS	0.08	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OH-0370	TRUMBULL ENERGY CENTER	OH	P0122331	221112	09/07/2017 ACT	940 MW combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Volatile Organic Compounds (VOC)	State-of-the-art combustion design	2	LB/H		BACT-PSD	NSPS	0.5	T/YR	PER ROLLING 12 MONTH PERIOD	0		SEE NOTES
OK-0156	NORTHSTAR AGRI INDUSTRIES	OK	2013-0109-C PSD	311223	07/31/2013 ACT	The new Northstar Agri Industries â€“ Enid facility will be designed to convert 2,500 TPD of seeds into crude oil and RBD oil. The facility consists of several processing steps to prepare seed and remove up to 100 million gallons per year of crude oil and RBD oil.	Fire Pump Engine	Diesel	550	hp	Volatile Organic Compounds (VOC)	Good Combustion	0.35	LB/MMBTU	3-HOUR AVG	BACT-PSD	NSPS , NESHAP	0			0		
*SC-0193	MERCEDES BENZ VANS, LLC	SC	0560-0385-CA	336112	04/15/2016 ACT	Mercedes-Benz Vans, LLC (Mercedes-Benz Vans) owns and operates a van assembly plant in Ladson, Charleston County, South Carolina (the Charleston plant). Mercedes-Benz Vans submitted a Prevention of Significant Deterioration (PSD) construction and operating permit application in for the expansion of existing assembly processes and addition of new processes, including a body	Emergency Generators and Fire Pump	No. 2 Fuel Oil	1500	hp	Volatile Organic Compounds (VOC)	Must meet the standards of 40 CFR 60, Subpart IIII	100	HR/YR	12 MONTH ROLLING SUM	BACT-PSD		0			0		
TX-0728	BASF	TX	118239, N200	325311	04/01/2015 ACT	Ammonia production with hydrogen imported	Emergency Diesel Generator	Diesel	1500	hp	Volatile Organic Compounds (VOC)	Minimized hours of operations Tier II engine	0.7	LB/H		OTHER CASE-BY-CASE	N/A	0.02	T/YR		0		
TX-0876	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency generator	DIESEL	0		Volatile Organic Compounds (VOC)	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency firewater pumps		0		Volatile Organic Compounds (VOC)	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0888	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial NSR, PSD, and GHG project to construct and operate an Olefins Unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers, flares, cooling towers, wastewater treatment plant, loadout facilities, miscellaneous auxiliary support facilities, and associated MSS.	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	Ultra-low Sulfur Diesel	0		Volatile Organic Compounds (VOC)	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	0			0		
*TX-0904		TX	156571, PSDTX1564, GHGPSDTX195		09/09/2020 ACT	new polyethylene plant that will produce both LLDPE and HDPE	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Volatile Organic Compounds (VOC)	100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101	0			BACT-PSD		0			0		
*TX-0905	DIAMOND GREEN DIESEL	TX	160299, PSDTX1576, GHGPSDTX200	325998	09/16/2020 ACT	a new renewable diesel fuels plant that will produce renewable diesel fuel and other renewable fuels.	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Volatile Organic Compounds (VOC)	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		0			0		
VA-0327	PERDUE AGRIBUSINESS, LLC	VA	60277	311222	07/12/2017 ACT	Facility consists of a grain elevator and a soybean oil extraction plant.	Emergency Generator	Diesel	0		Volatile Organic Compounds (VOC)		0.49	LB/HR		BACT-PSD	MACT	0			0		
WV-0025	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Emergency Generator	Diesel	2015.7	HP	Volatile Organic Compounds (VOC)		1.24	LB/H		BACT-PSD		0			0		
*TX-0933	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	Emergency Generators	Ultra-low sulfur diesel (no more than 15	0		Volatile Organic Compounds (VOC)	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

VOC

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Volatile Organic Compounds (VOC)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Nitrous Oxide (N2O)	GOOD COMBUSTION PRACTICES	0.67	LB/MMBTU		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATORS	DIESEL	1500	KW	Nitrous Oxide (N2O)	GOOD COMBUSTION PRACTICES	0.0013	LB/MMBTU		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Nitrous Oxide (N2O)	Good Combustion Practices	0.0013	LB/MMBTU		BACT-PSD		0			0		
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	1027 MW POWER PLANT (FKA PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Nitrous Oxide (N2O)	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0014	LB/MMBTU		BACT-PSD	OPERATING PERMIT	0			0.0014	LB/MMBTU	
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	PSD-LA-767	221112	09/26/2013 ACT		2000 KW Diesel Fired Emergency Generator Engine	Diesel	20.4	MMBTU/hr	Nitrous Oxide (N2O)	Good combustion practices	0			BACT-PSD	OPERATING PERMIT	0			0		
AK-0082	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT03	211111	01/23/2015 ACT	OIL GAS EXPLORATION AND PRODUCTION FACILITY.	Emergency Camp Generators	Ultra Low Sulfur Diesel	2695	hp	Carbon Dioxide Equivalent (CO2e)		2332	TONS/YEAR	COMBINED	BACT-PSD		0			0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	AQ0934CPT01	212221	06/30/2017 ACT	The Donlin Gold Project is a gold mine located 24 miles north of Crooked Creek, Alaska on the Kuskokwim River, about 280 miles northwest of Anchorage. The deposit has proven and probable reserves estimated at 33.9 million ounces of gold at 2.1 g/t and could produce up to 1.5 million ounces annually. SIC Code 1041; NAICS Code 212221.	Black Start and Emergency Internal Cumbustion Engines	Diesel	1500	kWe	Carbon Dioxide Equivalent (CO2e)	Good Combustion Practices	2781	TPY	YEARLY	BACT-PSD	NSPS	0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Carbon Dioxide	GOOD COMBUSTION PRACTICES	163	LB/MMBTU		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Methane	GOOD COMBUSTION PRACTICES	0.0061	LB/MMBTU		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATOR SN-62	DIESEL	625	HP	Nitrous Oxide (N2O)	GOOD COMBUSTION PRACTICES	0.67	LB/MMBTU		BACT-PSD		0			0		
AR-0140	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R0	331111	09/18/2013 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	EMERGENCY GENERATORS	DIESEL	1500	KW	Nitrous Oxide (N2O)	GOOD COMBUSTION PRACTICES	0.0013	LB/MMBTU		BACT-PSD		0			0		
*AR-0161	SUN BIO MATERIAL COMPANY	SUN BIO MATERIAL COMPANY	AR	2384-AOP-R0	322110	09/23/2019 ACT	A kraft paper mill designed with one high yield Kraft softwood Fiberline and two linerboard machiens. The plant is initially sized to support an approximate, nominal linerboard production capacity of 4,400 machine dry tons per day at varying base weights.	Emergency Engines	Diesel	0		Carbon Dioxide Equivalent (CO2e)	Good Combustion Practices	164	LB/MMBTU		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Carbon Dioxide	Good Combustion Practices	163	LB/MMBTU		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Methane	Good Combustion Practices	0.0061	LB/MMBTU		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Nitrous Oxide (N2O)	Good Combustion Practices	0.0013	LB/MMBTU		BACT-PSD		0			0		
CO-0067	LANCASTER PLANT	KERR-MCGEE GATHERING	CO	12WE1492	211111	06/04/2013 ACT	Natural gas processing facility.	Emergency Generator	diesel	19950	gal per year	Carbon Dioxide Equivalent (CO2e)	NSPS IIII compliant.	0			BACT-PSD	NSPS , MACT , OPERATING PERMIT	0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Engine	Diesel	0		Carbon Dioxide	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	14.6	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0328	ENI - HOLY CROSS DRILLING PROJECT	ENI U.S. OPERATING COMPANY, INC.	FL	OCS-EPA-R4007	211112	10/27/2011 ACT	The project, known as the Holy Cross Drilling Project, will mobilize the Pathfinder drillship, and support vessels to drill in the Gulf of Mexico, Lloyd Ridge lease block 411, to determine the presence of natural gas. The exploratory drilling activity will consist of two phases: the initial drilling phase and the well completion phase; the Pathfinder will complete both phases. The operation will	Emergency Fire Pump Engine	Diesel	0		Carbon Dioxide	Use of good combustion practices, based on the current manufacturerâ€™s specifications for this engine	2.4	TONS PER YEAR	12-MONTH ROLLING	BACT-PSD		0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - Development Driller 1	Diesel	2229	hp	Carbon Dioxide Equivalent (CO2e)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	77.84	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
FL-0338	SAKE PROSPECT DRILLING PROJECT	BHP BILLITON PETROLEUM, INC.	FL	OCS-EPA-R4008	211111	05/30/2012 ACT	The facility consists of a mobile offshore drilling unit (MODU) using either the Transocean ultra-deepwater C.R. Luigs or the Transocean semisubmersible DD1 to conduct exploratory oil and natural gas drilling in lease blocks within the DeSoto Canyon area of the Gulf of Mexico.	Emergency Generator Diesel Engine - C.R. Luigs	diesel	2064	hp	Carbon Dioxide Equivalent (CO2e)	Use of good combustion practices based on the current manufacturerâ€™s specifications for these engines, use of low sulfur diesel fuel, positive crankcase ventilation, turbocharger with aftercooler, high pressure fuel injection with aftercooler	72.06	T/12MO ROLLING TOTAL	TONS PER YEAR 12 MONTH ROLLING TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Carbon Dioxide Equivalent (CO2e)	good combustion practices	788.5	TONS/YR	ROLLING 12 MONTH TOTAL	BACT-PSD		0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Carbon Dioxide	good combustion practices	1.55	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		0			0		
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	12-219	325311	10/26/2012 ACT	NITROGENEOUS FERTILIZER MANUFACTURING	Emergency Generator	diesel fuel	142	GAL/H	Methane	good combustion practices	0.0001	G/KW-H	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD		0			0		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Carbon Dioxide	good combustion practices	1.55	LB/KW-H	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Methane	good combustion practices	0.0001	G/KW-H	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD		0			0		
IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	IA	PN 13-037	325311	07/12/2013 ACT	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.	Emergency Generators	diesel fuel	180	GAL/H	Carbon Dioxide Equivalent (CO2e)	good combustion practices	509	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	BACT-PSD		0			0		
IL-0114	CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	13060007	325311	09/05/2014 ACT	Plant will produce urea and ammonia, but ammonia production will be limited to a maximum of 3 months of the year (4,880 tpd urea and 2,789 tpd ammonia).	Emergency Generator	distillate fuel oil	3755	HP	Carbon Dioxide Equivalent (CO2e)	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	432	TPY		BACT-PSD		0			0		
IL-0129	CPV THREE RIVERS ENERGY CENTER	CPV THREE RIVERS, LLC	IL	16060032	221112	07/30/2018 ACT	The proposed facility is designed to generate dispatch power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would burn natural gas and ultra-low sulfur diesel (ULSD) as a backup fuel. Other units include an auxiliary boiler, fuel heater, engines, natural gas piping and	Emergency Engines	Ultra-low sulfur diesel	0		Carbon Dioxide Equivalent (CO2e)		0			BACT-PSD		0			0		
IL-0130	JACKSON ENERGY CENTER	JACKSON GENERATION, LLC	IL	17040013	221112	12/31/2018 ACT	The proposed facility is designed to generate dispatch power. It will consist of two combined-cycle generating units, each with a combustion turbine and associated heat recovery steam generator (HRSG). The turbines would only burn natural gas. Other units include an auxiliary boiler, fuel heater, emergency engines, natural gas piping and components, circuit breakers and roadways	Emergency Engine	Ultra-Low Sulfur Diesel	1500	kW	Carbon Dioxide Equivalent (CO2e)		225	TONS/YEAR		BACT-PSD		0			0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Carbon Dioxide Equivalent (CO2e)	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN	1186	TONS	12 CONSECUTIVE MONTH PERIOD	BACT-PSD		0			0		
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	141-31003-00579	221112	12/03/2012 ACT	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Carbon Dioxide Equivalent (CO2e)	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN POST COMBUSTION CARBON CAPTURE	1186	TONS	12 CONSECUTIVE MONTH PERIOD	BACT-PSD		500	HOURS OF OPERATION	YEARLY	0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMIT ALLOWS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Carbon Dioxide	USE OF GOOD ENGINEERING DESIGN AND EFFICIENT ENGINES MEETING APPLICABLE NSPS AND MACT STANDARDS	84	T/YR	TWELVE CONSECUTIVE MONTHS	BACT-PSD		0			0		
IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	IN	T147-30464-00060	221210	06/27/2012 ACT	THE PERMIT ALLOWS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Carbon Dioxide	USE OF GOOD ENGINEERING DESIGN AND EFFICIENT ENGINES MEETING APPLICABLE NSPS AND MACT STANDARDS	84	T/YR	TWELVE CONSECUTIVE MONTHS	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Carbon Dioxide	GOOD COMBUSTION PRACTICES	526.39	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0173	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Carbon Dioxide	GOOD COMBUSTION PRACTICES	527.4	G/BHP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0179	OHIO VALLEY RESOURCES, LLC	OHIO VALLEY RESOURCES, LLC	IN	147-32322-00062	325311	09/25/2013 ACT	NITROGENOUS FERTILIZER PRODUCTION PLANT	DIESEL-FIRED EMERGENCY GENERATOR	NO. 2 FUEL OIL	4690	B-HP	Carbon Dioxide	GOOD COMBUSTION PRACTICES	526.39	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	DIESEL FIRED EMERGENCY GENERATOR	NO. 2, DIESEL	3600	BHP	Carbon Dioxide	GOOD COMBUSTION PRACTICES	526.39	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0180	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	129-33576-00059	325311	06/04/2014 ACT	A STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	FIRE PUMP		500	HP	Carbon Dioxide	GOOD COMBUSTION PRACTICES	527.4	G/B-HP-H	3-HR AVERAGE	BACT-PSD		0			0		
IN-0263	MIDWEST FERTILIZER COMPANY LLC	MIDWEST FERTILIZER COMPANY LLC	IN	129-36943-00059	325311	03/23/2017 ACT	STATIONARY NITROGEN FERTILIZER MANUFACTURING FACILITY	EMERGENCY GENERATORS (EU014A AND EU-014B)	DISTILLATE OIL	3600	HP EACH	Carbon Dioxide	GOOD COMBUSTION PRACTICES	1044	TON/12 CONSEC. MONTH	EACH	BACT-PSD		500	H/YR EACH		0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency generator EU-6006	Diesel	2800	HP	Carbon Dioxide Equivalent (CO2e)	Tier II diesel engine	811	TONS	12 CONSECUTIVE MONTHS	BACT-PSD	NESHAP , NSPS	0			0		
*IN-0317	RIVERVIEW ENERGY CORPORATION	RIVERVIEW ENERGY CORPORATION	IN	T147-39554-00065	324110	06/11/2019 ACT	direct coal hydrogenation plant	Emergency fire pump EU-6008	Diesel	750	HP	Carbon Dioxide Equivalent (CO2e)	Engine that complies with Table 4 to Subpart IIII of Part 60	217	TONS	12 CONSECUTIVE MONTHS	BACT-PSD	NESHAP , NSPS	0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	2527 MW POWER PLANT (7X1 PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Nitrous Oxide (N2O)	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0014	LB/MMBTU		BACT-PSD	OPERATING PERMIT	0			0.0014	LB/MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	2527 MW POWER PLANT (7X1 PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	163	LB/MMBTU		BACT-PSD	OPERATING PERMIT	0			163	LB/MMBTU	

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	221112	08/16/2011 ACT	2827 MW 4-UNIT PLANT (NEW FACILITY). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-	EMERGENCY DIESEL GENERATOR	DIESEL	1250	HP	Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0061	LB/MMBTU		BACT-PSD	OPERATING PERMIT	0			0.0061	LB/MMBTU	
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-778	325110	05/23/2014 ACT		Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)		2682	HP	Carbon Dioxide Equivalent (CO2e)	Compliance with 40 CFR 60 Subpart IIII, operate the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	56	TPY	ANNUAL MAXIMUM	BACT-PSD		0			0		
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators No. 1 & No. 2	Diesel	1341	HP	Carbon Dioxide Equivalent (CO2e)		77	TPY	ANNUAL MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	SASOL CHEMICALS (USA) LLC	LA	PSD-LA-779	325211	05/23/2014 ACT	The Low Density Polyethylene (LDPE) Unit will produce LDPE by the high pressure polymerization of ethylene.	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105,	Diesel	2682	HP	Carbon Dioxide Equivalent (CO2e)	Compliance with 40 CFR 60 Subpart IIII, operating the engine in accordance with the engine manufacturerâ€™s instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel	56	TPY	ANNUAL MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
LA-0305	LAKE CHARLES METHANOL FACILITY	LAKE CHARLES METHANOL, LLC	LA	PSD-LA-803(M1)	325199	06/30/2016 ACT	Proposed facility to produce methanol, H2, H2SO4, CO2, Argon and electricity from Pet Coke	Diesel Engines (Emergency)	Diesel	4023	hp	Carbon Dioxide Equivalent (CO2e)	Complying with 40 CFR 60 Subpart IIII	0			BACT-PSD		0			0		
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	PSD-LA-767	221112	09/26/2013 ACT		2000 KW Diesel Fired Emergency Generator Engine	Diesel	20.4	MMBTU/hr	Carbon Dioxide	Good combustion practices	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	PSD-LA-767	221112	09/26/2013 ACT		2000 KW Diesel Fired Emergency Generator Engine	Diesel	20.4	MMBTU/hr	Methane	Good combustion practices	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0308	MORGAN CITY POWER PLANT	LOUISIANA ENERGY AND POWER AUTHORITY (LEPA)	LA	PSD-LA-767	221112	09/26/2013 ACT		2000 KW Diesel Fired Emergency Generator Engine	Diesel	20.4	MMBTU/hr	Nitrous Oxide (N2O)	Good combustion practices	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0309	BENTELER STEEL TUBE FACILITY	BENTELER STEEL / TUBE MANUFACTURING CORPORATION	LA	PSD-LA-774(M1)	331111	06/04/2015 ACT	A facility to produce 600,000 metric tons per year of seamless steel pipe from purchased billets. A steel production facility (including an electric arc furnace (EAF)) was added.	Emergency Generator Engines	Diesel	2922	hp (each)	Carbon Dioxide Equivalent (CO2e)		0			BACT-PSD		0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	horsepower	Carbon Dioxide Equivalent (CO2e)	Compliance with NSPS Subpart IIII	37	TPY		BACT-PSD	OPERATING PERMIT , NSPS	0			0		
*LA-0312	ST. JAMES METHANOL PLANT	SOUTH LOUISIANA METHANOL LP	LA	PSD-LA-780(M-1)	325998	06/30/2017 ACT	New MeOH plant designed to produce 5,275 metric tons per day of refined methanol from natural gas and carbon dioxide (CO2) feedstock	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	Diesel	1474	horsepower	Carbon Dioxide Equivalent (CO2e)	Compliance with NSPS Subpart IIII	84	TPY		BACT-PSD	NSPS , OPERATING PERMIT	0			0		
LA-0313	ST. CHARLES POWER STATION	ENTERGY LOUISIANA, LLC	LA	PSD-LA-804	221112	08/31/2016 ACT	The 2x Charles Power Station (SCPS) is a new electric power generating facility consisting of two (2) natural gas-fired combined cycle gas turbines, each with a heat recovery stem generator unit equipped with duct burners, and one (1) steam generator turbine. The SCPS will will have a predicted net nominal output of 980 MW at ISO conditions with supplemental duct firing.	SCPS Emergency Diesel Generator 1	Diesel	2584	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices	0			BACT-PSD	OPERATING PERMIT	0			0		
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 1	Diesel	5364	HP	Carbon Dioxide Equivalent (CO2e)	Proper design and operation; energy efficiency measures	0			BACT-PSD	OPERATING PERMIT	0			0		
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Emergency Diesel Generator 2	Diesel	5364	HP	Carbon Dioxide Equivalent (CO2e)	Proper design and operation; energy efficiency measures	0			BACT-PSD	OPERATING PERMIT	0			0		
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 1	Diesel	751	HP	Carbon Dioxide Equivalent (CO2e)	Proper design and operation; use of ultra-low sulfur diesel	0			BACT-PSD	OPERATING PERMIT	0			0		
*LA-0315	G2G PLANT	BIG LAKE FUELS LLC	LA	PSD-LA-781	325110	05/23/2014 ACT	The G2G Plant will be a natural gas to gasoline production facility which will use natural gas to produce methanol that will be subsequently converted into gasoline.	Fire Pump Diesel Engine 2	Diesel	751	HP	Carbon Dioxide Equivalent (CO2e)	Proper design and operation; use of ultra-low sulfur diesel	0			BACT-PSD	OPERATING PERMIT	0			0		
LA-0316	CAMERON LNG FACILITY	CAMERON LNG LLC	LA	PSD-LA-766(M3)	221210	02/17/2017 ACT	a facility to liquefy natural gas for export (5 trains)	emergency generator engines (6 units)	diesel	3353	hp	Carbon Dioxide Equivalent (CO2e)	good combustion practices	0			BACT-PSD		0			0		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Emergency Generator Engines (4 units)	Diesel	0		Carbon Dioxide Equivalent (CO2e)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0317	METHANEX - GEISMAR METHANOL PLANT	METHANEX USA, LLC	LA	PSD-LA-761(M4)	325199	12/22/2016 ACT	methanol plant (Unit I and Unit II) to produce 6000 metric tons of methanol by steam reforming natural gas	Firewater pump Engines (4 units)	diesel	896	hp (each)	Carbon Dioxide Equivalent (CO2e)	complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0			BACT-PSD	NSPS , NESHAP	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 3 Engine	Diesel Fuel	600	hp	Carbon Dioxide Equivalent (CO2e)	Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0323	MONSANTO LULING PLANT	MONSANTO COMPANY	LA	PSD-LA-890	325320	01/09/2017 ACT	Chemical Manufacture	Fire Water Diesel Pump No. 4 Engine	Diesel Fuel	600	hp	Carbon Dioxide Equivalent (CO2e)	Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII	0			BACT-PSD	NSPS	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Firewater Pumps	Diesel Fuel	634	kW	Carbon Dioxide Equivalent (CO2e)	Good Combustion Practices and Good Operation and Maintenance Practices.	44	T/YR	ANNUAL TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	09/21/2018 ACT	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Large Emergency Engines (>50kW)	Diesel Fuel	5364	HP	Carbon Dioxide Equivalent (CO2e)	Good Combustion of Practices and Good Operation and Maintenance Practices	1481	T/YR	ANNUAL TOTAL	BACT-PSD	OPERATING PERMIT	0			0		
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG complex will produce ethylene, propylene, ethylene glycol, high-density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Generator Diesel Engines	Diesel Fuel	550	hp	Carbon Dioxide Equivalent (CO2e)	Compliance with the limitations imposed by 40 CFR 63 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
*LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	01/06/2020 ACT	The FG LA Complex will produce ethylene, propylene, ethylene glycol, high-density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and	Emergency Fire Water Pumps	Diesel Fuel	550	hp	Carbon Dioxide Equivalent (CO2e)	Compliance with the limitations imposed by NSPS 40 CFR 60 Subpart IIII and operating the engine in accordance with the engine manufacturer's instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.	0			BACT-PSD	NSPS , NESHAP	0			0		
*MA-0043	MIT CENTRAL UTILITY PLANT	MASSACHUSETTS INSTITUTE OF TECHNOLOGY	MA	NE-15-018	611310	06/21/2017 ACT	MIT proposes to construct and operate two new 22 megawatt (MW) combined heat and power (CHP) combustion turbines/heat recovery steam generators and a new cold start engine at its existing Central Utility Plant.	Cold Start Engine	ULSD	19.04	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)		163.61	LB/MMBTU		BACT-PSD	SIP , OPERATING PERMIT	3115	LB/HR		0		
MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	81-11	221112	11/17/2011 ACT	Utility--Natural gas fired combustion turbine	Diesel fuel-fired combustion engine (RICE)	Diesel	732	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices	716.6	LB/H	TEST	BACT-PSD	NSPS , NESHAP , OTHER	0			0		
MI-0406	RENAISSANCE POWER LLC	LS POWER DEVELOPMENT LLC	MI	51-13	221112	11/01/2013 ACT	For technical questions regarding this permit, please contact the permit engineer, Melissa Byrnes, at 517-284-6790. Thank you.	EUEMERGRICE, Two (2) 1,000kW diesel-fueled emergency reciprocating internal combustion	Diesel	1000	kW	Carbon Dioxide Equivalent (CO2e)	Good combustion practices.	1731.4	T/YR	TEST PROTOCOL; BOTH UNITS COMBINED	BACT-PSD		0			0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	Diesel	500	H/YR	Carbon Dioxide Equivalent (CO2e)	Good combustion and design practices.	223	T/YR	BASED UPON A 12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0421	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16	321219	08/26/2016 ACT	Particleboard manufacturing	Dieself fire pump engine (EUFIREPUMP in FGRICE)	Diesel	500	H/YR	Carbon Dioxide Equivalent (CO2e)	Good combustion and design practices.	56	T/YR	BASED UPON A 12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0423	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16	221112	01/04/2017 ACT	Natural gas combined cycle power plant.	EUEMENGINE (Diesel fuel emergency engine)	Diesel Fuel	22.68	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good combustion practices	928	T/YR	12-MO. ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	Diesel	500	H/YR	Carbon Dioxide Equivalent (CO2e)	Good combustion and design practices.	209	T/YR	12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	Diesel	500	H/YR	Carbon Dioxide Equivalent (CO2e)	Good combustion and design practices.	70	T/YR	12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0425	GRAYLING PARTICLEBOARD	ARAUCO NORTH AMERICA	MI	59-16A	321219	05/09/2017 ACT	Particleboard manufacturing.	EUFIREPUMP in FGRICE (Diesel fire pump engine)	Diesel	500	H/YR	Carbon Dioxide Equivalent (CO2e)	Good combustion and design practices.	56	T/YR	12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (North Plant): Emergency Engine	Diesel	1341	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices.	383	T/YR	12-MO. ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	MARSHALL ENERGY CENTER LLC	MI	167-17 AND 168-17	221112	06/29/2018 ACT	Natural gas combined cycle power plant (two plants: north and south)	EUEMENGINE (South Plant): Emergency Engine	Diesel	1341	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices.	383	T/YR	12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	DTE ELECTRIC COMPANY	MI	19-18	221112	07/16/2018 ACT	Natural gas combined-cycle power plant	EUEMENGINE: Emergency engine	Diesel	2	MW	Carbon Dioxide Equivalent (CO2e)	Energy efficient design.	161	T/YR	12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and energy efficiency measures.	406	T/YR	12-MONTH ROLLING TIME PERIOD	BACT-PSD		0			0		
*MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and energy efficiency measures.	1590	T/YR	12-MONTH ROLLING TIME PERIOD	BACT-PSD		0			0		
*MI-0442	THOMAS TOWNSHIP ENERGY, LLC	THOMAS TOWNSHIP ENERGY, LLC	MI	210-18	221112	08/21/2019 ACT	New power plant	FGEMENGINE	Diesel	1100	KW	Carbon Dioxide Equivalent (CO2e)		444	T/YR	12-MO ROLL. TIME PERIOD; EACH ENGINE	BACT-PSD		0			0		
*MI-0445	INDECK NILES, LLC	INDECK NILES, LLC	MI	75-16B	221112	11/26/2019 ACT	Natural gas combined cycle power plant	EUEMENGINE (diesel fuel emergency engine)	diesel fuel	22.68	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good combustion practices	928	T/YR	12-MO ROLLING TIME PERIOD	BACT-PSD		0			0		
OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	P0110840	221112	06/18/2013 ACT	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency generator	diesel	2250	KW	Carbon Dioxide Equivalent (CO2e)		878	T/YR	PER ROLLING 12-MONTHS	BACT-PSD	OPERATING PERMIT	0			0		
OH-0360	CARROLL COUNTY ENERGY	CARROLL COUNTY ENERGY	OH	P0113762	221112	11/05/2013 ACT	Natural gas fired combined cycle gas turbine electric generating station of nominal capacity of 742 MW	Emergency generator (P003)	diesel	1112	KW	Carbon Dioxide Equivalent (CO2e)		433.96	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0363	NTE OHIO, LLC		OH	P0116610	221112	11/05/2014 ACT	Combined-cycle, natural gas-fired power plant	Emergency generator (P002)	Diesel fuel	1100	KW	Carbon Dioxide Equivalent (CO2e)	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII	474	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	OH	P0117655	221112	08/25/2015 ACT	962 MW (gross winter output) combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2346	HP	Carbon Dioxide Equivalent (CO2e)	Efficient design	683	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0367	SOUTH FIELD ENERGY LLC	SOUTH FIELD ENERGY LLC	OH	P0119495	221112	09/23/2016 ACT	1150 MW combined-cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	2947	HP	Carbon Dioxide Equivalent (CO2e)	Efficient design	858	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0368	PALLAS NITROGEN LLC	PALLAS NITROGEN LLC	OH	P0118959	325311	04/19/2017 ACT	Natural gas-based facility for the manufacture of nitrogenous products.	Emergency Generator (P009)	Diesel fuel	5000	HP	Carbon Dioxide Equivalent (CO2e)	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII	1289	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0370	TRUMBULL ENERGY CENTER	TRUMBULL ENERGY CENTER	OH	P0122331	221112	09/07/2017 ACT	940 MW combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Carbon Dioxide Equivalent (CO2e)	Efficient design	445	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
OH-0372	OREGON ENERGY CENTER	OREGON ENERGY CENTER	OH	P0121049	221112	09/27/2017 ACT	Combined cycle gas turbine (CCGT) facility	Emergency generator (P003)	Diesel fuel	1529	HP	Carbon Dioxide Equivalent (CO2e)	state of the art combustion design	445	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0374	GUERNSEY POWER STATION LLC	GUERNSEY POWER STATION LLC	OH	P0122594	221112	10/23/2017 ACT	1,650 MW combined cycle combustion turbine electrical generating facility	Emergency Generators (2 identical, P004 and P005)	Diesel fuel	2206	HP	Carbon Dioxide Equivalent (CO2e)	good operating practices (proper maintenance and operation)	120	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Generator Engine (P001)	Diesel fuel	2206	HP	Carbon Dioxide Equivalent (CO2e)	Efficient design	116.8	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	OH	P0122829	221112	11/07/2017 ACT	Combined cycle combustion turbine power generation facility	Emergency Diesel Fire Pump Engine (P002)	Diesel fuel	700	HP	Carbon Dioxide Equivalent (CO2e)	Efficient design	40.1	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0376	IRONUNITS LLC - TOLEDO HBI	IRONUNITS LLC - TOLEDO HBI	OH	P0123395	331111	02/09/2018 ACT	Hot briquetted iron production	Emergency diesel-fired generator (P007)	Diesel fuel	2682	HP	Carbon Dioxide Equivalent (CO2e)	Equipment design and maintenance requirements	163.6	LB/MMBTU		BACT-PSD		683	T/YR	PER ROLLING 12 MONTH PERIOD	0		
OH-0377	HARRISON POWER	HARRISON POWER	OH	P0122266	221112	04/19/2018 ACT	1000 MW natural gas-fired combined cycle combustion turbine plant	Emergency Diesel Generator (P003)	Diesel fuel	1860	HP	Carbon Dioxide Equivalent (CO2e)	Efficient design and proper maintenance and operation	109.2	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	Emergency Diesel-fired Generator Engine (P007)	Diesel fuel	3353	HP	Carbon Dioxide Equivalent (CO2e)	good operating practices (proper maintenance and operation)	200	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	PTTGCA PETROCHEMICAL COMPLEX	OH	P0124972	325110	12/21/2018 ACT	Petrochemical Complex	1,000 kW Emergency Generators (P008 - P010)	Diesel fuel	1341	HP	Carbon Dioxide Equivalent (CO2e)	good operating practices (proper maintenance and operation)	80	T/YR	PER ROLLING 12 MONTH PERIOD	BACT-PSD		0			0		
OH-0379	PETMIN USA INCORPORATED	PETMIN USA INCORPORATED	OH	P0125024	331111	02/06/2019 ACT	Merchant Pig Iron Production	Emergency Generators (P005 and P006)	Diesel fuel	3131	HP	Carbon Dioxide Equivalent (CO2e)	Tier IV engine Good combustion practices	3632	LB/H		BACT-PSD		181.6	T/YR		526.6	G/BHP-H	
OK-0154	MOORELAND GENERATING STA	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	2008-302-C(M-1)PSD	221112	07/02/2013 ACT	WFEC operates the Mooreland Generating Station to generate wholesale electricity which is transmitted over WFEC's system. The facility was originally constructed in 1963. The electricity is sold in rural areas of approximately 3/4 of the state of Oklahoma and part of New Mexico. The Mooreland Generating Station currently consists of three high-pressure boilers	DIESEL-FIRED EMERGENCY GENERATOR ENGINE	DIESEL	1341	HP	Carbon Dioxide Equivalent (CO2e)	A TIER 3 CERTIFIED ENGINE OPERATED < 100 HR/YR.	81.2	TPY		BACT-PSD	N/A	0			0		
OK-0156	NORTHSTAR AGRI IND ENID	NORTHSTAR AGRI INDUSTRIES	OK	2013-0109-C PSD	311223	07/31/2013 ACT	The new Northstar Agri Industries â€" Enid facility will be designed to convert 2,500 TPD of seeds into crude oil and RBD oil. The facility consists of several processing steps to prepare seed and remove up to 100 million gallons per year of crude oil and RBD oil.	Fire Pump Engine	Diesel	550	hp	Carbon Dioxide	Good Combustion	0			BACT-PSD	NSPS	0			0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	Fire pump engine	Ultra-low sulfur diesel	15	gal/hr	Carbon Dioxide Equivalent (CO2e)		9	TON	12-MONTH ROLLING BASIS	BACT-PSD		0			0		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	LACKAWANNA ENERGY CENTER, LLC	PA	35-00069A	221112	12/23/2015 ACT	This plan approval is for the construction and temporary operation of three (3) identical General Electric Model 7HA.02 natural gas fired combustion turbines and heat recovery steam generator with duct burners (CT/HRSG). Each CT/HRSG combined-cycle process block includes one (1) combustion gas turbine and one (1) heat recovery steam generator with duct burners with all three (3) CT/HRSG	2000 kW Emergency Generator	Ultra-low sulfur Diesel	0		Carbon Dioxide Equivalent (CO2e)		81	TONS	12-MONTH ROLLING BASIS	BACT-PSD		0			0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two nominal 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Emergency Generator		0		Carbon Dioxide Equivalent (CO2e)		44	TPY	12-MONTH ROLLING BASIS	BACT-PSD	NSPS	0			0		
PA-0311	MOXIE FREEDOM GENERATION PLANT	MOXIE FREEDOM LLC	PA	40-00129A	221112	09/01/2015 ACT	The Project is for the construction and operation of two nominal 1 x 1 power blocks, each consisting of a combustion gas turbine (CGT or CT) and a steam turbine (ST) configured in single shaft alignment, where each CT and ST train share one common electric generator. The turbines to be used for this project are Two General Electric (GE) 7HA.02 CTs, each in 1 x 1 single shaft combined- cycle	Fire Pump Engine	diesel	0		Carbon Dioxide Equivalent (CO2e)		14	TPY	12-MONTH ROLLING BASIS	BACT-PSD	NSPS	0			0		
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	ENERGY ANSWERS ARECIBO, LLC	PR	R2-PSD 1	221119	04/10/2014 ACT	Energy Answers Arecibo is a new resource recovery facility capable of producing up to 77 megawatts (MW) of electrical power while combusting municipal solid waste, as the primary fuel.	Emergency Diesel Generator	ULSD Fuel oil # 2	0		Carbon Dioxide Equivalent (CO2e)		183	T/YR		BACT-PSD		0			0		
TX-0766	GOLDEN PASS LNG EXPORT TERMINAL	GOLDEN PASS PRODUCTS, LLC	TX	116055, PSDTX1386, GHGPSDTX100	486210	09/11/2015 ACT	Liquefied natural gas (LNG) export terminal.	Emergency Engine Generators	Diesel	750	hp	Carbon Dioxide Equivalent (CO2e)	Equipment specifications & work practices - Good combustion practices and limited operational hours	40	HR/YR		BACT-PSD		123	TPY		0		
TX-0799	BEAUMONT TERMINAL	PHILLIPS 66 PIPELINE LLC	TX	18295, PSDTX1466, GHGPSDTX139	424710	06/08/2016 ACT	This marine terminal receives, stores, and distributes various volatile organic liquids (VOLs) and refined petroleum products.	Fire pump engines	diesel	0		Carbon Dioxide Equivalent (CO2e)	Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	72.16	T/YR		BACT-PSD		0			0		
TX-0799	BEAUMONT TERMINAL	PHILLIPS 66 PIPELINE LLC	TX	18295, PSDTX1466, GHGPSDTX139	424710	06/08/2016 ACT	This marine terminal receives, stores, and distributes various volatile organic liquids (VOLs) and refined petroleum products.	EMERGENCY ENGINES	diesel	0		Carbon Dioxide Equivalent (CO2e)	Equipment specifications and good combustion practices. Operation limited to 100 hours per year.	6.79	T/YR		BACT-PSD		0			0		
TX-0872	CONDENSATE SPLITTER FACILITY	MAGELLAN PROCESSING, L.P.	TX	118270 PSDTX1398M1 GHGPSDTX62	324110	10/31/2019 ACT	The site uses a series of separation towers, collectively known as a condensate splitter. Condensate is received and refined into light and heavy naphtha, kerosene/distillate, residuum and liquified petroleum gas. The refined materials are either stored into storage tanks or loaded into either a truck or marine	Emergency Generators	ultra low sulfur diesel	0		Carbon Dioxide Equivalent (CO2e)	Limiting duration and frequency of generator use to 100 hr/yr. Good combustion practices will be used to reduce VOC including maintaining proper air-to-fuel ratio.	0			BACT-PSD		0			0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency generator	DIESEL	0		Carbon Dioxide Equivalent (CO2e)	Tier 4 exhaust emission standards specified in 40 CFR Â§ 1039.101, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	MOTIVA ENTERPRISE LLC	TX	PSDTX1546 AND GHGPSDTX186	325110	02/06/2020 ACT	new steam cracking plant (Ethylene Plant) for production of ethylene using ethane as feedstock in Port Arthur, Jefferson County, Texas. The Ethylene Plant will manufacture ethylene, crude propylene, crude butadiene, pyrolysis gasoline and other by-products using a steam cracking process	Emergency firewater pumps		0		Carbon Dioxide Equivalent (CO2e)	Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation	0			BACT-PSD	NSPS , MACT	0			0		
TX-0888	ORANGE POLYETHYLENE PLANT	CHEVRON PHILLIPS CHEMICAL COMPANY LP	TX	155952 PSDTX1556 GHGPSDTX192	325211	04/23/2020 ACT	An initial X3E, Y3D, and GHG project to construct and operate an Olefins unit, two Polyethylene (PE) Units, and auxiliary support facilities. This permit will consist of furnaces, boilers, heaters, storage tanks, emergency engines, fugitive piping, thermal oxidizers, flares, cooling towers, wastewater treatment plant, loadout facilities, miscellaneous auxiliary support facilities, and associated MSS.	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	Ultra-low Sulfur Diesel	0		Carbon Dioxide Equivalent (CO2e)	well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.	0			BACT-PSD	NSPS , MACT	0			0		
*TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	DIAMOND GREEN DIESEL	TX	160299, PSDTX1576, GHGPSDTX200	325998	09/16/2020 ACT	a new renewable diesel fuels plant that will produce renewable diesel fuel and other renewable fuels.	EMERGENCY GENERATOR	ULTRA LOW SULFUR DIESEL	0		Carbon Dioxide Equivalent (CO2e)	limited to 100 hours per year of non-emergency operation	0			BACT-PSD		0			0		

Xcel Energy - Blue Lake
RBLC Summary Tables
Emergency Generator Engines

CO_2

NOTE: Draft determinations are marked with a " * " beside the RBLC ID.

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	Process Name	Fuel	Through-put	Units	Pollutant	Emission Control Description	Emission Limit 1	Limits Units 1	Avg Time	CASE-BY-CASE BASIS	OTHER REQUIREMENTS	Emission Limit 2	Limits Units2	Avg Time2	Standard Emission Limit	Standard Limit Units	Standard Limit Avg Time
VA-0325	GREENSVILLE POWER STATION	VIRGINIA ELECTRIC AND POWER COMPANY	VA	52525	221112	06/17/2016 ACT	The proposed project will be a new, nominal 1,000 MW combined cycle electric power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-	DIESEL-FIRED EMERGENCY GENERATOR 3000 kW (1)	DIESEL FUEL	0		Carbon Dioxide Equivalent (CO2e)	Good Combustion Practices/Maintenance	163.6	LB/MMBTU		N/A		1178	T/YR	12 MO ROLLING TOTAL	0		
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	04/26/2018 ACT	Natural gas-fired combined cycle power plant	Emergency Diesel GEN	Ultra Low Sulfur Diesel	500	H/YR	Carbon Dioxide Equivalent (CO2e)	use of S15 ULSD and high efficiency design and operation	981	T/YR	12 MO ROLLING TOTAL	BACT-PSD	NSPS , SIP	0			0		
*VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	52610-1	221112	06/24/2019 ACT	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/hr natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Emegency Fire Water Pump	Ultra Low Sulfur Diesel	500	HR/YR	Carbon Dioxide Equivalent (CO2e)	good combustion practices, high efficiency design, and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.	106	T/YR	12 MO ROLLING TOTAL	BACT-PSD	NSPS , SIP	0			0		
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT		WI	18-JJW-017	221112	04/24/2018 ACT	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	Diesel-Fired Emergency Generators	Diesel Fuel	0		Carbon Dioxide Equivalent (CO2e)	The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices	0			BACT-PSD	NSPS , NESHAP	0			0		
*WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	SIO INTERNATIONAL	WI	18-JJW-022	334419	04/24/2018 ACT	Nitrogen Plant	P42 -Diesel Fired Emergency Generator	Diesel Fuel	0		Carbon Dioxide Equivalent (CO2e)	Good Combustion Practices and The Use of Ultra-low Sulfur Fuel	0			BACT-PSD	NSPS , NESHAP	0			0		
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	MOUNDSVILLE POWER, LLC	WV	R14-0030	221112	11/21/2014 ACT	Nominal 549 mW(output) natural gas-fired combined cycle power plant.	Emergency Generator	Diesel	2015.7	HP	Carbon Dioxide Equivalent (CO2e)		2416	LB/H		BACT-PSD		0			0		
*TX-0933	NACERO PENWELL FACILITY	NACERO TX 1 LLC	TX	164137 PSDTX1594 GHGPSDTX207	325110	11/17/2021 ACT	Nacero proposes to construct and operate a plant that will convert natural gas to methanol and then convert methanol to a finished gasoline component.	Emergency Generators	Ultra-low sulfur diesel (no more than 15	0		Carbon Dioxide Equivalent (CO2e)	limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR Â§ 1039.101) exhaust emission standards	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-07 - Air Separation Plant Emergency Generator	Diesel	700	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Carbon Dioxide	Good Combustion Practices	163	LB/MMBTU		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Methane	Good Combustion Practices	0.0061	LB/MMBTU		BACT-PSD		0			0		
AR-0163	BIG RIVER STEEL LLC	BIG RIVER STEEL LLC	AR	2305-AOP-R6	331111	06/09/2019 ACT	THE FACILITY WILL CONSIST OF TWO ELECTRIC ARC FURNACES TO MELT SCRAP IRON AND STEEL, LADLE METALLURGY FURNACES (LMF) TO ADJUST THE CHEMISTRY, A RH DEGASSER AND BOILER FOR FURTHER REFINEMENT, AND CASTERS.	Emergency Engines	Diesel	0		Nitrous Oxide (N2O)	Good Combustion Practices	0.0013	LB/MMBTU		BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-04 - Emergency Fire Water Pump	Diesel	920	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
LA-0292	HOLBROOK COMPRESSOR STATION	CAMERON INTERSTATE PIPELINE LLC	LA	PSD-LA-769(M-1)	486210	01/22/2016 ACT	Natural gas compressor station supporting the Cameron LNG Facility in Hackberry, Cameron Parish, Louisiana	Emergency Generators No. 1 & No. 2	Diesel	1341	HP	Carbon Dioxide Equivalent (CO2e)		77	TPY	ANNUAL MAXIMUM	BACT-PSD	OPERATING PERMIT	0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD1--A 1500 HP diesel fueled emergency engine	Diesel	1500	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and energy efficiency measures.	406	T/YR	12-MONTH ROLLING TIME PERIOD	BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-02 - North Water System Emergency Generator	Diesel	2922	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-03 - South Water System Emergency Generator	Diesel	2922	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
KY-0110	NUCOR STEEL BRANDENBURG	NUCOR	KY	V-20-001	331111	07/23/2020 ACT	Plate steel manufacturing plant. The facility recycles scrap steel and scrap substitutes using the electric arc furnace (EAF) process. Scrap steel and scrap substitutes will be delivered to the facility by barge, rail, and truck. Scrap steel, scrap substitutes, and flux will be charged to the EAF and melted by applying electric current through the feed mixture. Molten metal will be tapped to a ladle	EP 10-01 - Caster Emergency Generator	Diesel	2922	HP	Carbon Dioxide Equivalent (CO2e)	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.	0			BACT-PSD		0			0		
MI-0441	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	MI	74-18	221112	12/21/2018 ACT	Natural gas combined-cycle power plant.	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	Diesel	6000	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices and energy efficiency measures.	1590	T/YR	12-MONTH ROLLING TIME PERIOD	BACT-PSD		0			0		

Attachment I.3

Engine Generator Manufacturer (Wartsila) Diesel Particulate Filter Memo

Title:	Summary on Diesel Particulate Filter Technology	**Doc.ID:**	DBAD995323
		Revision:	-
Author:	Hanna Strandberg	**Status:**	Checked
Checked by:	Hanna Strandberg / 17.08.2016	**Pages:**	1 (2)
Organisation:	- General Energy Solutions		
Project:	IN026 – WNS-P DOCVISION		

Released to Xcel to Public distribution for permitting purposes.
2024-05-24 | Greg Bosley, Wartsila Energy, Engine Power Plants

Summary on Diesel Particulate Filter Technology

1 Diesel Particulate Filter Technology

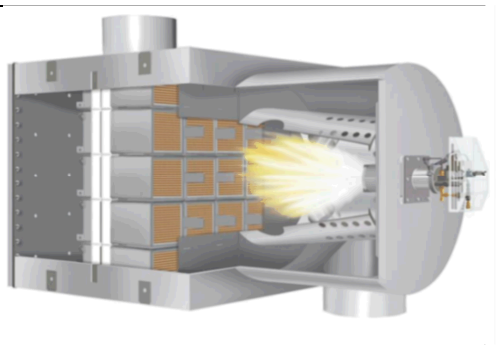
Diesel Particulate Filters (DPF) are established technology for automotive engine applications but experience on large bore medium speed diesel engines is limited. The reason for this is that the fuel used in larger bore engines often has a higher concentration of impurities, in particular the sulfur content has been higher, the difference in lube oil quality (the automotive industry often uses synthetic oils) and the different load profiles. The load variations in automotive applications partly regenerate the filter while power plant engines have traditionally been optimized for steady high load.

The best diesel particulate abatement is achieved with a so called “wall flow filter” where the flue gases passes through a porous filtering material. This filter type is extremely efficient but has a high pressure drop. DPF can also be coated, enabling chemical reaction for lowering the regeneration temperature. Non coated DPFs need periodically active regeneration, either with fuel injection or burners. There are reports from the non-road mobile engine/car industry that the DPF PM removal efficiency is typically over 85 %.

2 Wärtsilä experience

Wärtsilä has no installed DPF references, but in year 2010 a Wärtsilä diesel engine equipped with a diesel oxidation catalyst and particle oxidation catalyst (DOC + POC) for PM removal in combination with a SCR system was tested in the field. The engine was operating on LBF (palm oil). The initial measured PM removal efficiency of the DOC&POC system was approx. 70 % (when measuring both filterable and condensable particulates) and the back pressure over 100 mbar, far in excess of the normal limits on back pressure for this type of engine. The engine was derating due to the extreme back pressure. When considering only the dry

filterable particulates measured with ISO 9096, EPA method 17 or 5 (method typically used in thermal power industry) no reduction could be seen. The chemical analyses showed that the particle reduction over DOC+POC was mostly derived from the oxidation of the organic carbon fraction of the condensable part of the PM emission. Since the initial field measurements did not meet the expectations, the test was stopped at an early stage and no long time experience was obtained.

	
Diesel Oxidation Catalyst (DOC) regeneration with catalyst material (POC)	Diesel particulate filter Regeneration with catalyst material and burner

The DPF system is expensive (approximately double the price of a Selective Catalytic Reduction system) and needs frequent regeneration (fuel) or mechanical cleaning which has a negative impact on OPEX cost and plant availability. The high backpressure of the system will cause power reduction and efficiency drop on the engine. An induced draft exhaust fan to try to mitigate this will add to the plant's parasitic load consumption figures and to plant complexity. The regeneration sequences need proper control, otherwise an uncontrolled situation with extreme exhaust gas temperatures may destroy the DPF. The sum of all these factors excludes the combined DPF+SCR system from the recommended Best Available Control Technique (BACT) list.

3 Conclusion

As a leading engine builder and as an environmentally conscious manufacturer, Wartsila has kept a close watch on the development of DPF technology over the years and has had contact with suppliers of automotive DPF technology to discuss their technology and the aspects of it which might apply to large bore, medium speed engines using a variety of fuels. To date no supplier has come forth with a technology which meets our customers demand.

Attachment I.4

Fugitive Dust Control Plan

Fugitive Dust Control Plan

Attachment I.4 to Appendix I

Prepared for

Xcel Energy – Blue Lake

November 2023

Fugitive Dust Control Plan
Attachment I.3 to Appendix I

November 2023

Contents

I.3.1 Introduction 1

I.3.1.1 Sources of Fugitive Dust 2

I.3.1.2 Applicable Regulations 2

I.3.2 Fugitive Dust Control Implementation 3

I.3.2.1 Fugitive Dust Monitoring 3

I.3.2.1.1 Frequency 3

I.3.2.1.2 Action Trigger 3

I.3.3 Fugitive Dust Mitigation Measures 4

I.3.1.1 Paved Roads 4

I.3.4 Training 5

I.3.5 Recordkeeping 6

Abbreviations

FDCP or Plan	Fugitive Dust Control Plan
MPCA	Minnesota Pollution Control Agency
mph	miles per hour
Facility	Xcel Energy - Blue Lake

I.3.1 Introduction

The objective of this Fugitive Dust Control Plan (Plan of FDCP) is to describe the dust control measures that are will be implemented during the operation of the Xcel Blue Lake Facility (Facility). The Facility is a power plant that includes fuel delivery traffic on paved roads. The Plan provides a description of the applicable fugitive dust regulations, and the planned measures for mitigating dust emissions from this source. The Plan will be used as a living document and will be revised and updated as needed to support the Facility.

I.3.1.1 Sources of Fugitive Dust

This Plan is specific to fugitive dust generated from paved roads.

I.3.1.2 Applicable Regulations

The Project is subject to the state of Minnesota regulations to control fugitive dust emissions under Minn. Rules 7011.0150, which is a general prohibition against generating excessive fugitive dust:

> *A. No person shall cause or permit the handling, use, transporting, or storage of any material in a manner which may allow avoidable amounts of particulate matter to become airborne.*
>
> *B. No person shall cause or permit a building or its appurtenances or* ***a road****, or a driveway, or an open area to be constructed****, used****, repaired, or demolished* ***without applying all such reasonable measures as may be required to prevent particulate matter from becoming airborne****.* ***All persons shall take reasonable precautions to prevent the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate.*** *The commissioner may require such reasonable measures as may be necessary to prevent particulate matter from becoming airborne including, but not limited to, paving or frequent* ***clearing of roads****, driveways, and parking lots; application of dust-free surfaces;* ***application of water****; and the planting and maintenance of vegetative ground cover.* ***[emphasis added]***

Xcel developed the dust control measures for the Project based on this regulation.

A major air permit amendment application for the Blue Lake Conversion Project (the Project) was originally submitted in January 2023 and resubmitted in November 2023. Because the Project will trigger the Prevention of Significant Deterioration (PSD) requirements for PM, PM_{10}, $PM_{2.5}$, a Best Available Control Technology (BACT) Analysis was conducted for the paved roads. The BACT determination is summarized in the following table and this Plan has been developed to meet this requirement.

Proposed BACT	Compliance Demonstration
Fugitive Dust Control Plan	Follow procedures outlined in the fugitive dust control plan, including daily visible emission checks when fuel is being delivered.

I.3.2 Fugitive Dust Control Implementation

The mitigation measures to minimize fugitive dust emissions may include activities like sweeping, watering, and speed limits. Control measures operational-related activities are described in Section D.3.3 of this Plan.

I.3.2.1 Fugitive Dust Monitoring

I.3.2.1.1 Frequency

Dust control personnel will monitor the paved roads at least once per operating day (e.g., on days in which fuel deliveries are occurring). The frequency of fugitive dust monitoring may be adjusted, if necessary, to prevent and mitigate fugitive dust creation.

In addition to the routine monitoring, Xcel will evaluate fugitive dust control measures and the Plan on a routine and as-needed basis. The Plan will be reviewed at least annually, and updated will be made to document any new control measures implemented over the past year, any changes to fugitive dust sources and their levels of emissions, and whether any further changes to the fugitive dust control strategy are needed.

I.3.2.1.2 Action Trigger

During daily fugitive dust inspections, visible fugitive dust from the paved roads will trigger one or more of the following actions:

- Evaluate and document the control measure(s) currently in use;
- Possible reapplication or enhancement of the measure(s); and
- Temporary curtailment of the dust generating activity, if needed, based on weather conditions.

The observation of visible emissions does not, determinately, demonstrate noncompliance with any applicable requirement. It is a signal to investigate and, if necessary, take reasonable and appropriate corrective action.

I.3.3 Fugitive Dust Mitigation Measures

The following control measures will apply to potential fugitive dust sources from operational activities:

- Minimize extraneous vehicle travel on fuel delivery routes through signage and training, except for activities where traffic on those routes has been approved;
- Facility staff will monitor visible dust and control measures daily when fuel is being delivered.;
- Speed limits for traffic on paved and unpaved roads will be a maximum of 15 miles per hour (mph);
- Traffic will follow posted speed limits on any paved state, county, or local roads; and
- Signage and training will be used to establish the Project speed limits.

I.3.1.1 Paved Roads

The following control measures will apply to potential fugitive dust sources related to paved roads.

- Site speed limit (15 miles per hour);
- Inspect road surface for excess silt, mud, etc.
- Use of a street sweeper and/or water to remove accumulated dust if indicated by inspection results and/or observed visible emissions
- If a visible emissions occur, conduct additional street sweeping or apply water as a dust suppressant.

I.3.4 Training

An essential part of the implementation of the Plan is appropriate training for the personnel involved. Xcel will provide training for contractors, drivers and personnel responsible for dust control at the facility during new employee training and at an annual refresher training and periodically as needed for new hires. Xcel will assign dust control personnel for the facility to implement the dust control measures specified in this Plan and in the air permit issued by the Minnesota Pollution Control Agency (MPCA). Facility staff will be responsible for monitoring the implementation dust control measures. They will also be responsible for maintain proper documentation.

Training will cover the following subjects as needed for individual levels of responsibility:

- Employee responsibilities;
- Dust control measures;
- Corrective actions;
- Dust observation and visibility training;
- Weather observations;
- Forms and record keeping; and
- Reporting.

Responsibilities of the environmental compliance staff, or designated facility staff, will be:

- Leading an annual review of dust control measures for operational sources in this Plan and any changes implemented since the last annual review;
- Monitoring visible fugitive dust daily when fuel is being delivered, such that sufficient dust control measures, can be applied expeditiously when necessary;
- Tracking operational activites so that daily visible emissions observations are performed when fuel is being delivered; and
- Documenting control measure implementation as described in Section D.3.3.

I.3.5 Recordkeeping

Inspections of operational activites that are potential sources of fugitive dust will occur daily when fuel is being delivered.. The the environmental compliance staff, or designated facility staff, will be responsible for recording the following information on a daily basis:

- Weather conditions (temperature and precipitation);
- Deployment of any road sweepers and/or watering.
- Cases where visible dust inspections required implementation of control measures; and
- Areas treated with additional control measures.

The facility will retain these records for a period of at least five years from the date the records are generated.

Additional details regarding recordkeeping requirements for this Plan may be developed during the permitting process with MPCA. This Plan will be updated, if needed, once the air permit and other plans have been finalized.

Best Available Control Technology Analysis Addendum

Addendum to Appendix I to the Permit Application for Blue Lake Conversion Project

Prepared for
Xcel Energy – Blue Lake

March 2024

4300 MarketPointe Drive, Suite 200
Minneapolis, MN 55435
952.832.2600
www.barr.com

Best Available Control Technology Analysis Addendum

March 2024

Contents

1 Executive Summary 3
2 Process Description Summary and BACT Applicability 5
2.1 Process Description Summary 5
2.2 BACT Applicability 5
3 BACT Methodology 6
3.1 Top-Down BACT Approach 6
3.1.1 Step 1 - Identify all Available Control Technologies 6
3.1.2 Step 2 - Eliminate Technically Infeasible Control Technologies 7
3.1.3 Step 3 - Rank Technically Feasible Options by Control Effectiveness 7
3.1.4 Step 4 - Evaluate Technically Feasible Control Technologies 7
3.1.5 Step 5 - Select BACT 8
3.2 Constraints on BACT Emission Limits 8
4 BACT for Storage Tanks 9
4.1 Storage Tank VOC Emissions 9
4.1.1 Step 1 – Identify All Available Control Technologies 9
4.1.2 Step 2 – Technical Feasibility of Control Technologies 10
4.1.3 Step 3 – Effectiveness of Feasible Control Technologies 10
4.1.4 Step 4 – Evaluation of Feasible Control Technologies 10
4.1.5 Step 5 – BACT Selection 10
5 GHG BACT for Equipment Leaks 11
5.1.1 Step 1 – Identify All Available Control Technologies 11
5.1.2 Step 2 – Technical Feasibility of Control Technologies 11
5.1.3 Step 3 – Effectiveness of Feasible Control Technologies 11
5.1.4 Step 4 – Evaluation of Feasible Control Technologies 11
5.1.5 Step 5 – BACT Selection 12

List of Tables

Table I.1-1 BACT Analysis Addendum Summary....4
Table I.4-1 Available VOC Emission Control Technologies....9
Table I.5-1 Available GHG Emission Control Technologies....11

List of Appendices

Appendix I BACT Analysis

1 Executive Summary

Xcel Energy submitted a major permit amendment application for the Blue Lake Conversion Project (Project) in December of 2022. Upon review of the permit application and the Best Available Control Technology (BACT) analysis by the Minnesota Pollution Control Agency (MPCA), it was determined that a Volatile Organic Compound (VOC) BACT analysis should be submitted for the two 100,000-gallon diesel tanks and a Greenhouse Gas (GHG) BACT analysis should be submitted for equipment leaks associated with the Project.

The major permit amendment application included the following updates at the facility:

- Retire the four Turbodyne combustion turbines (CTs) (EQUI 1, EQUI 2, EQUI 3, and EQUI 4)
- Modify the synthetic minor emission limits as presented in the facility air permit (COMG 2) for the two General Electric natural gas fired CTs (EQUI 7 and EQUI 8) to allow increased utilization
- Install three (3) 9.37 MW Wartsila dual fuel (natural gas and diesel) internal combustion engine generators
- Install four (4) diesel-fired emergency generators
- Install two (2) 100,000 gallon diesel tanks included in the permit application as an insignificant activity.

The Project was a major modification for stationary sources per 40 CFR Part 52.21(b)(1)(i), subject to Prevention of Significant Deterioration (PSD) requirements for the following pollutants:

- Particulates Matter (PM) meaning PM-Total (filterable + condensable fractions)
- Particulate Matter with an Aerodynamic Diameter of less than 10 Microns (PM_{10})
- Particulate Matter with an Aerodynamic Diameter of less than 2.5 Microns ($PM_{2.5}$)
- Nitrogen Oxides (NO_X)
- Carbon Monoxide (CO)
- Volatile Organic Compounds (VOC)
- Greenhouse Gases (GHG)

For this BACT Addendum, Xcel Energy completed an analysis of control technologies and strategies for VOC emissions from the two 100,000-gallon diesel tanks and GHG emissions from equipment leaks.

This BACT analysis follows the U.S. Environmental Protection Agency's (EPA) five-step top-down approach, as specified in the EPA's draft NSR Workshop Manual.

- Step 1 – Identify All Available Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
- Step 3 – Rank Remaining Control Technologies by Control Effectiveness
- Step 4 – Evaluate Most Effective Control Technologies and Document Results
- Step 5 – Select BACT

Table I.1-1 summarize the results of the BACT analysis.

Table I.1-1 BACT Analysis Addendum Summary

Source	Fuel Source	PSD Pollutants	Technology Proposed as BACT	Basis	Compliance Demonstration
Storage Tanks	Diesel	VOC	Good tank design	RBLC	- Fixed roof - Pressure relief valve (conservation vent) - Submerged fill pipe - Light tank color
Equipment Leaks	Natural Gas	GHG	Proper piping design, best management practices, and implementation of an audio, visual, and olfactory (AVO) Program	RBLC	- Proper piping design conforming to ANSI, API, ASME, or other standards - Best management practices to prevent, detect, and repair leaks - Implementation of an AVO program

2 Process Description Summary and BACT Applicability

2.1 Process Description Summary

The Xcel Energy - Blue Lake is located at 1200 70th Street S in Shakopee, Scott County, Minnesota and operates under the terms and conditions of Air Permit 13900010-104.

Xcel Energy submitted a major permit amendment application for the Blue Lake Conversion Project ("the Project") in December of 2022, which included the following updates at the facility:

- Retire the four Turbodyne CTs (EQUI 1, EQUI 2, EQUI 3, and EQUI 4).
- Modify the synthetic minor emission limits as presented in the facility air permit (COMG 2) for the two General Electric CTs (EQUI 7 and EQUI 8) to allow increased utilization.
- Install three (3) 9.37 MW Wartsila dual fuel (natural gas and diesel) internal combustion engine generators.
- Install four (4) diesel-fired emergency generators.
- The project also includes the potential for fuel oil tanker traffic on paved roads sufficient to supply the new engine generators at their maximum capacity for 8760 hours per year. The emissions based on potential traffic levels were evaluated for air permitting purposes; Actual traffic levels will be much lower.
- Installation of two 100,000 gallons diesel fuel tanks that were listed as an insignificant activity in the permit application.

The Project triggered the PSD requirements as summarized in Section 2.2.

2.2 BACT Applicability

BACT is required for new units, modified units, and units for which there is a change in the method of operation. Since the Project is major under PSD for VOC, any unit that is part of the Project must go through review for those pollutants. Therefore, a VOC BACT review has been completed for the two 100,000-gallon diesel tanks and is found in Section 4. The project is also major for GHG, so A GHG BACT analysis has been completed for equipment leaks and is found in Section 5.

3 BACT Methodology

BACT is defined as an emission limitation based on the maximum emission reduction achievable after a case-by-case review of potential emission controls which takes into account energy, environmental, and economic impacts. This emissions limit may be achieved by a variety of means, such as control technologies, clean fuels, inherently lower polluting processes or alternative operating practices. A PSD permit must express a BACT determination as an enforceable emission limitation or work practice as defined in Rule 336.2801(f)[1].

3.1 Top-Down BACT Approach

This BACT analysis has been conducted in accordance with Section 165(a) (4) of the Clean Air Act (at 40 CFR Part 52.21(j)), and Rule 1810. Proposed BACT emissions limits have been selected using the "top-down" approach specified in the U.S. EPA's draft New Source Review Workshop Manual, (October 1990),[2] using the five-step process as outlined below.

3.1.1 Step 1 - Identify all Available Control Technologies

All available control technology options are identified for each emission unit. A control technology is considered available for a specific pollutant if it could practically be applied to the specific emission unit. To identify all available control technologies to be evaluated as part of the BACT analysis, the following sources were consulted:

- U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC)
- The EPA's Clean Air Technology Center (CATC) website
- Other EPA and state air quality permits

RBLC data is presented in the Attachment 1.2 Addendum.

[1] "Best available control technology means an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator -- on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs -- determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61, adopted by reference in R 336.2801a. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

[2] The workshop manual can be found at U.S. EPA's website http://www.epa.gov/NSR/ttnnsr01/gen/wkshpman.pdf.

For preparation of the GHG BACT analysis, Xcel Energy followed the EPA guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" (EPA-457/B-11-001, March 2011).

3.1.2 Step 2 - Eliminate Technically Infeasible Control Technologies

Each control option identified in Step 1 is evaluated, using source-specific factors, to determine if it is technically feasible. If physical, chemical and engineering principles demonstrate that a technology could not be successfully used on the emission unit, then that technology is determined to be technically infeasible. Economics are not considered in the determination of technical feasibility. Technologies which are determined to be infeasible are eliminated from further consideration.

3.1.3 Step 3 - Rank Technically Feasible Options by Control Effectiveness

All technically feasible options are ranked in order of overall control effectiveness. Rankings are based on the level of achievable emissions control. The control effectiveness listed will be representative of the level of emission control which can be achieved by the control option at the operating conditions of the emission unit being reviewed. If the most effective control technology is selected as BACT, then Step 4 need not be completed.

3.1.4 Step 4 - Evaluate Technically Feasible Control Technologies

The economic, environmental, and energy impacts of each control option are evaluated under Step 4. Step 4 is only required if the most effective control option is not proposed as BACT.

Step 4 economic impacts, when required, are analyzed using the procedures found in the EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001) and the May 2016 revision to the Selective Catalytic Reduction section. The manual and recent updates are currently located at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost manual. Cost effectiveness is evaluated on dollar per ton ($/ton) basis using the annual operating cost ($/yr) divided by the annual emission reduction achieved by the control device (ton/yr). A control technology is considered economically infeasible if the control cost on a dollar per ton basis exceeds the amount which other sources in the same industrial classification have incurred.

The environmental impact analysis, when required, assesses collateral environmental impacts associated with control of the regulated pollutant in question. Impacts considered may include solid or hazardous waste generation, wastewater discharges from a control device, visibility impacts, collateral increases in emissions of other criteria or non-criteria pollutants, increased water consumption, and land use. The environmental impact analysis is conducted based on consideration of site-specific circumstances.

The energy impact analysis, when required, considers whether use of an emission control technology results in any significant or unusual energy penalties or benefits. Energy use may be evaluated on an energy used per unit of production basis; energy used per ton of pollutant controlled or total annual energy use. Energy impacts may consider whether or not use of an emission control technology will have an adverse impact on local energy supplies due to increased fuel consumption or the loss of fuel production or power generation.

3.1.5 Step 5 - Select BACT

Based on technical considerations and economic, environmental and energy impacts the proposed BACT for each emissions unit will include:

- A pollutant-specific emission control option as BACT, or a combination of controls when appropriate
- A BACT emission limit
- A BACT limit compliance demonstration method

3.2 Constraints on BACT Emission Limits

BACT emission limits for sources subject to New Source Performance Standards ([NSPS] 40 CFR Part 60) or National Emission Standards for Hazardous Air Pollutants ([NESHAPS] 40 CFR Part 61) cannot be less stringent than the applicable standards. In other words, applicable 40 CFR Part 60 NSPS or 40 CFR Part 61 NESHAPS standards provide a "floor" for BACT emission limits. Applicable Part 60 and 61 standards are provided in the technical report supporting the Permit to Install application.

Maximum Achievable Control Technology [MACT] standards issued under 40 CFR Part 63 are not used to establish the BACT floor. However, MACT requirements which limit PSD pollutants as surrogates for control of HAP emissions may be considered in the BACT analysis as a level of emission control considered to be achievable based on the review process EPA uses for establishing MACT limitations.

4 BACT for Storage Tanks

The Project will have two 100,000-gallon storage tanks for diesel fuel. The VOC BACT for the storage tanks is included below.

4.1 Storage Tank VOC Emissions

The two diesel fuel storage tanks will contain ultra-low sulfur diesel fuel used to operate the three compression ignition reciprocating internal combustion engine (RICE) driven generator units that can operate on either primarily natural gas with diesel as a pilot fuel or on 100% diesel fuel and the four emergency diesel generators. Ultra-low sulfur diesel has a very low vapor pressure and VOC emissions from these tanks will be negligible. US EPA regulations for storage tanks such as CFR 60 Subpart Ka do not require emission controls for diesel storage tanks based on its low vapor pressure. The diesel fuel storage tanks will be fixed roof storage tanks equipped with submerged fill lines and conservation vents. A submerged fill line prevents VOC emissions from splashing liquids when the tanks are filled. Conservation vents are used to minimize atmospheric venting of air from the tank vapor space associated with diurnal temperature changes and small changes in tank inventory levels. Conservation vents only allow air into a tank to prevent a vacuum from forming and only allow air out of a tank to prevent over pressuring.

Based on the low emission rates from this type of storage tank, no emission limits are required.

The proposed diesel storage tank design is consistent with other BACT determinations for diesel storage tanks used to supply diesel at other electric power generation facilities.

4.1.1 Step 1 – Identify All Available Control Technologies

Potential control technologies and work practices for controlling VOC from diesel storage tanks were identified using the RBLC database and include the following:

- Good tank design, including:
  - Fixed roof
  - PRV (conservation vent)
  - Submerged fill pipe
  - Light tank color

Table I.4-1 Available VOC Emission Control Technologies

Technology	Description
Good Tank Design	- Fixed roof - PRV (conservation vent) - Submerged fill pipe - Light tank color

4.1.2 Step 2 – Technical Feasibility of Control Technologies

All tank design specifications identified above are technically feasible.

4.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The implementation of the technically feasible tank design specifications are the only technically feasible control options for minimizing VOC emissions from the storage tanks based on a search of the RBLC, CATC, and California BACT determinations. The combination of these measures is therefore the top-ranked control technology. Implementing this design results in lower VOC emissions and is consistent with a survey of recent VOC BACT limitations listed in the RBLC database. Refer to Attachment I.2-1 for more detail.

4.1.4 Step 4 – Evaluation of Feasible Control Technologies

Consideration of Step 4 is not required since the most effective control measures are proposed as BACT.

4.1.5 Step 5 – BACT Selection

The tank design specifications identified in Step 1 are proposed as BACT. The rationale for this selection is as follows:

- The proper tank design is consistent with previous BACT determinations for VOC emissions from diesel storage tanks.
- The proper tank design is technically and economically feasible.

Proposed BACT for the diesel storage tanks subject to VOC BACT are summarized in Table 1.4-2.

Table I.4-2 Proposed VOC BACT Demonstration for Diesel Storage Tanks

Category	Demonstration
Compliance Demonstration	Good tank design: - Fixed roof - Pressure relief valve (conservation vent) - Submerged fill pipe - Light tank color

5 GHG BACT for Equipment Leaks

The GHG BACT for equipment leaks is included below.

5.1 Equipment Leaks GHG Emissions

GHG emissions may occur from equipment leaks from the piping associated with the combustion turbines and emergency engines.

5.1.1 Step 1 – Identify All Available Control Technologies

Potential design strategies and work practices for controlling GHG from equipment leaks were identified using the RBLC database and include the following:

- Proper piping design conforming to ANSI, API, ASME, or other standards
- Best management practices to prevent, detect, and repair leaks
- Implementation of an audio, visual, and olfactory (AVO) program

Table I.5-1 Available GHG Emission Control Technologies

Technology	Description
Proper Design and Best Practices	- Proper piping design conforming to ANSI, API, ASME, or other standards - Best management practices to prevent, detect, and repair leaks - Implementation of an AVO program

5.1.2 Step 2 – Technical Feasibility of Control Technologies

All potential design strategies and work practices identified above are feasible.

5.1.3 Step 3 – Effectiveness of Feasible Control Technologies

The implementation of the technically feasible design and operational measures are the only technically feasible control options for minimizing GHG emissions from equipment leaks. The combination of these measures is therefore the top-ranked control technology. Implementing these measures results in lower GHG emissions and is consistent with a survey of recent GHG BACT limitations listed in the RBLC database. Refer to Attachment I.2-2 for more detail.

5.1.4 Step 4 – Evaluation of Feasible Control Technologies

Consideration of Step 4 is not required since the most effective control measures are proposed as BACT.

5.1.5 Step 5 – BACT Selection

The use of proper piping design, best management practices, and the implementation of an AVO Program are proposed as BACT. The rationale for this selection is as follows:

- The use of proper piping design, best management practices, and the implementation of an AVO Program minimizes GHG emissions and is consistent with previous BACT determinations for GHG emissions.
- The use of proper piping design, best management practices, and the implementation of an AVO Program are technically and economically feasible.

.

Proposed BACT for equipment leaks subject to GHG BACT are summarized in Table I.5-2.

Table I.5-2 Proposed GHG BACT Demonstration for Equipment Leaks

Category	Demonstration
Compliance Demonstration	- Proper piping design conforming to ANSI, API, ASME, or other standards - Best management practices to prevent, detect, and repair leaks - Implementation of an AVO program A plan for the AVO program will be prepared within 180 days of permit issuance, kept on-site at the facility and made available to MPCA for review upon request.

Attachment I.2 Addendum

RACT/BACT/LAER Clearinghouse Summary

Attachment 1.2 Addendum-1 Storage Tanks RBLC
Attachment 1.2 Addendum-2 Equipment Leaks RBLC

Attachment I.2 Addendum-1

Diesel Tank Storage RBLC

Xcel Blue Lake
RBLC Summary Tables
Diesel Storage Tanks

VOC

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH-PUT	THROUGH-PUT UNITS	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNITS	CASE-BY-CASE BASIS	EMISSION LIMIT 2	EMISSION LIMIT 2 UNITS	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNITS
AK-0088	LIQUEFACTION PLANT	ALASKA GASLINE DEVELOPMENT CORPORATION	AK	AQ1539CPT01	488999	7/7/2022	The Liquefaction Plant is planned to encompass 921 acres, including 901 acres onshore for the liquefied natural gas (LNG) Plant as well as 20 acres offshore for the Marine Terminal. The Liquefaction Plant will be the terminus of an approximately 807-mile gas pipeline, allowing natural gas from Alaska's North Slope to be shipped to outside markets. The stationary source will consist of structures and equipment associated with processing, storage, and loading of LNG. There will be three liquefaction trains combining to process up to approximately 20 million metric tons per annun of LNG.	Three Diesel Storage Tanks	Diesel	0		Volatile Organic Compounds (VOC)	Submerged Fill	0.01	TPY COMBINED	BACT-PSD	0		0	
AR-0124	EL DORADO SAWMILL	UNION COUNTY LUMBER COMPANY	AR	2348-AOP-R0	321113	8/3/2015	SAWMILL AFIN: 70-00032AFIN: 70-00032	THREE DIESEL STORAGE TANKS SN-15		0		Volatile Organic Compounds (VOC)	TANKS ARE LIGHT COLOR	0.4	LB/H	BACT-PSD	0		0	
IN-0273	ST. JOSEPH ENERGY CENTER	ST. JOSEPH ENERGY CENTER	IN	141-37912-00579	221112	6/22/2017	STATIONARY ELECTRIC UTILITY GENERATING STATION	DIESEL STORAGE TANK TK11	DIESEL	650	GALLONS	Volatile Organic Compounds (VOC)	THE USE OF GOOD DESIGN AND OPERATING PRACTICES. EACH TANK SHALL UTILIZE A FIXED ROOF.	0		BACT-PSD	0		0	
IN-0273	ST. JOSEPH ENERGY CENTER	ST. JOSEPH ENERGY CENTER	IN	141-37912-00579	221112	6/22/2017	STATIONARY ELECTRIC UTILITY GENERATING STATION	DIESEL STORAGE TANK TK50	DIESEL	5000	GALLONS	Volatile Organic Compounds (VOC)	THE USE OF GOOD DESIGN AND OPERATING PRACTICES. EACH TANK SHALL UTILIZE A FIXED ROOF.	0		BACT-PSD	0		0	
IN-0359	NUCOR STEEL	NUCOR STEEL	IN	107-45480-00038	331111	3/30/2023	stationary steel mini-mill	Diesel Storage Tank (DST #6)		1000	ns storage cap	Volatile Organic Compounds (VOC)	Submerged fill pipe and white painted tank shell and roof	0		BACT-PSD	0		0	
KY-0109	FRITZ WINTER NORTH AMERICA, LP	FRITZ WINTER NORTH AMERICA, LP	KY	V-16-022 R1	331511	10/24/2016	This facility consists of a gray iron foundry, casting, and machining operation that produces automotive parts in Simpson County, Kentucky. The facility comprises an approximately 95 acre site, consisting of scrap handling and preparation equipment, melt furnaces, sand and mineral storage, mixing and handling equipment, mold and core making facilities, casting equipment, and finishing facilities where castings are machined and coated. Once the planned two-phase construction is complete, the facility will be capable of producing 91,586 tons of gray iron for pouring and 3.5 million automotive brake rotors per year.	Diesel Storage Tank (EU76)		2000	gallons	Volatile Organic Compounds (VOC)	The diesel storage tank (EU76) shall be equipped with a permanent submerged fill pipe.	0		BACT-PSD	0		0	
LA-0363	HOLDEN WOOD PRODUCTS MILL	WEYERHAEUSER NR COMPANY	LA	PSD-LA-834	321113	10/2/2019	The Holden Wood Products Mill produces dimensional lumber. Current operations can be divided into the following areas: log yard operation, rough cutting, lumber drying, lumber finishing, and shipping.	Diesel Storage Tank		150000	gallons/yr	Volatile Organic Compounds (VOC)	Good Tank Design and Submerged Fill Page.	14000	GAL	BACT-PSD	0		0	
LA-0364	FG LA COMPLEX	FG LA LLC	LA	PSD-LA-812	325110	1/6/2020	The FG LA complex will produce ethylene, propylene, ethylene glycol, high density polyethylene, low density polyethylene, linear low-density polyethylene and polypropylene. To support the operation of these production plants, the complex will also include electric power and steam generating units (Utility), wastewater treatment (Central Wastewater Treatment Plant), storage and loading operations (Logistics), and associated flare systems.	DEG, EG, PEG, MEG, and Diesel Storage Tanks		0		Volatile Organic Compounds (VOC)	Storage vessels equipped with fixed roofs.	0		BACT-PSD	0		0	
LA-0366	HOLDEN WOOD PRODUCTS MILL	WEYERHAEUSER NR COMPANY	LA	PSD-LA-834(M-1)	321113	2/3/2021	The Holden Wood Products Mill produces dimensional lumber. Current operations can be divided into the following areas: log yard operation, rough cutting, lumber drying, lumber finishing, and shipping.	Diesel Storage Tanks		0		Volatile Organic Compounds (VOC)	Good Tank Design and Submerged Fill Pipe.	500	GAL	BACT-PSD	150	GAL	0	
LA-0390	DERIDDER SAWMILL	CSP DERIDDER, LLC	LA	PSD-LA-843	321113	5/10/2022	The DeRidder Sawmill will produce softwood dimensional lumber, wood chips, wood shavings, and residuals from regionally sourced southern yellow pine. The primary emission sources at the facility are from the lumber drying kilns.	T-1 - Diesel Storage Tank		0		Volatile Organic Compounds (VOC)	Use of a submerged fill pipe	0		BACT-PSD	0.001	TONS/YR	0	
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT		WI	18-JJW-017	221112	4/24/2018	Energy facility providing comfort heating, production-related steam, and emergency backup power to the Fabrication 818 plant.	T01, T02; T03 Diesel Storage Tank		0		Volatile Organic Compounds (VOC)	Submerged Fill Pipe	0		BACT-PSD	0		0	

Attachment I.2 Addendum-2

Equipment Leaks RBLC

Xcel Blue Lake
RBLC Summary Tables
Equipment Leaks

GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	NAICS	PERMIT DATE	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH-PUT	THROUGH-PUT UNITS	PROCESS NOTES	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNITS	CASE-BY-CASE BASIS	EMISSION LIMIT 2	EMISSION LIMIT 2 UNITS	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNITS
MD-0042	WILDCAT POINT GENERATION FACILITY	OLD DOMINION ELECTRIC CORPORATION (ODEC)	MD	CPCN CASE NO. 9327	221119	4/8/2014	1000 MEGAWATT COMBINED CYCLE NATURAL GAS-FIRED POWER PLANTFACILITY-WIDE PM10 EMISSION LIMIT = 278 TONS/YR FACILITY-WIDE PM2.5 EMISSION LIMIT = 272 TONS/YR FACILITY-WIDE SAM EMISSION LIMIT = 96 TONS/YR FACILITY-WIDE CO2E EMISSION LIMIT = 3,498,026 TONS/YR	EQUIPMENT LEAKS		0		NATURAL GAS PIPELINE COMPONENTS, INCLUDING VALVES, CONNECTORS, FLANGES, PUMP SEALS AND PRESSURE RELIEF VALVES WITHIN THE FACILITY BOUNDARY	Carbon Dioxide Equivalent (CO2e)		0		BACT-PSD	0		0	
MD-0045	MATTAWOMAN ENERGY CENTER	MATTAWOMAN ENERGY, LLC	MD	PSC CASE. NO. 9330	221119	11/13/2015	990 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANTNOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	EQUIPMENT LEAKS		0		NATURAL GAS PIPELINE COMPONENTS, INCLUDING VALVES, CONNECTORS, FLANGES, PUMP SEALS AND PRESSURE RELIEF VALVES WITHIN THE FACILITY BOUNDARY	Carbon Dioxide Equivalent (CO2e)	IMPLEMENTATION OF AN AUDIO, VISUAL AND OLFACTORY (AVO) PROGRAM ON FILE AT POWER PLANT SITE FOR REVIEW UPON REQUEST BY THE AGENCY. LEAKS DETECTED SHALL BE REPAIRED WITHIN FIVE DAYS OF DISCOVERY.	0		BACT-PSD	0		0	
MD-0046	KEYS ENERGY CENTER	KEYS ENERGY CENTER, LLC	MD	PSC CASE NO. 9297	221119	10/31/2014	735 MW COMBINED-CYCLE NATURAL GAS-FIRED POWER PLANT NOTE: PARTICULATE MATTER FACILITYWIDE EMISSIONS ARE PARTICULATE MATTER (FILTERABLE)	EQUIPMENT LEAKS		0		NATURAL GAS PIPELINE COMPONENTS, INCLUDING VALVES, CONNECTORS, FLANGES, PUMP SEALS AND PRESSURE RELIEF VALVES WITHIN THE FACILITY BOUNDARY	Carbon Dioxide Equivalent (CO2e)	IMPLEMENTATION OF AN AUDIO, VISUAL AND OLFACTORY (AVO) PROGRAM ON FILE AT POWER PLANT SITE FOR REVIEW UPON REQUEST BY THE AGENCY. LEAKS DETECTED SHALL BE REPAIRED WITHIN FIVE DAYS OF DISCOVERY.	0		BACT-PSD	0		0	
VA-0328	C4GT, LLC	NOVI ENERGY	VA	52588	221112	4/26/2018	Natural gas-fired combined cycle power plant	Equipment Leaks from Natural Gas Components		0		Work practice requirements	Carbon Dioxide Equivalent (CO2e)	Best management practices to prevent, detect and repair leaks of natural gas from the piping components.	0		BACT-PSD	0		0	
VA-0332	CHICKAHOMINY POWER LLC	CHICKAHOMINY POWER LLC	VA	52610-1	221112	6/24/2019	Natural gas-fired combined cycle power plant, three 1 x1 configuration, 310 MW each, no duct firing, air cooled with two 84 MMBtu/H natural gas-fired auxiliary boilers, three fuel gas heaters, an emergency generator, fire water pump, and circuit breakers.	Equipment Leaks from Natural Gas Components		0		Workpractice requirements	Carbon Dioxide Equivalent (CO2e)	Best management practices to prevent, detect and repair leaks of natural gas from the piping components.	0		BACT-PSD	0		0	
LA-0331	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	LA	PDS-LA-805	221210	9/21/2018	New Liquefied Natural Gas (LNG) production, storage, and export terminal.	Fugitive Equipment Leaks		0		Fugitive Emissions	Carbon Dioxide Equivalent (CO2e)	Proper piping design.	3141	T/YR	BACT-PSD	0		0	

Attachment 4 - Modeling Results

MINNESOTA POLLUTION CONTROL AGENCY

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

AQDM-06

Air Quality Dispersion Modeling (AQDM) results form

(Previously AQDMR-01)

Doc Type: Air Dispersion Modeling

OCT 30 2023

Acronym information on page 7

Instructions: Permit applicants required to conduct air dispersion modeling should submit two paper copies of the completed *Air Quality Dispersion Modeling results form (AQDM-06)* and all accompanying files to:

Air Quality Permit Document Coordinator
Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

Applicants may also submit an electronic version via email, in addition to the two paper copies. This is highly recommended. Please note that all assumptions made in the air dispersion modeling analysis could result in air permit requirements.

Electronic copies of the forms and accompanying files should be emailed to: AirModeling.PCA@state.mn.us. **Note:** The air modeling e-Service may not be used to submit air modeling results.

Facility information

Tempo AI ID number: 1860 AQ facility/permit ID number: 13900010 Today's date (mm/dd/yyyy): 10/27/2023

Three-letter modeling facility ID (ex., XEK = Xcel Energy Allen S. King, MEC = Mankato Energy Center, etc.): XBL

Facility name: Xcel Energy Blue Lake

Facility street address: 1200 70th St S

City: Shakopee County: Scott Zip code: 55379-2100 State: MN

Facility contact: Hannah Mathers, Xcel Energy Report prepared by: Jennifer Koenen, Barr Engineering Co

Facility contact phone: (763) 647-4338 Preparer phone: (952) 832-2682

Facility contact email address: Hannah.L.Mathers@xcelenergy.com Preparer email address: jkoenen@barr.com

*UTM coordinates of facility (NAD83, zone 15 extended **only**): x = 465,895.00 m East, y = 4,959,202.00 m North

**This should be the central location of the facility/source.*

These results are associated with (check all that apply):

- ☐ AERA or Dispersion/Deposition modeling for air toxics
- ☐ Environmental assessment worksheet
- ☐ Environmental impact statement
- ☐ Modeling information request
- ☐ Modeling Impacts from animal feedlots
- ☐ Siting an air monitoring station
- ☐ Siting a meteorological station
- ☐ Permit condition
- ☒ Permit modification
- ☒ Prevention of significant deterioration
- ☐ Screening modeling
- ☐ Special project
- ☐ State implementation plan

Project description (50 words or less)

Xcel Blue Lake Station plans to install three 10 MW disptachable, reiciprocating engines with capacity designed for starting and operating the plant with no external power supply. These units will replace Units 1-4 which will retire at the same time. In addition, the existing Blue Lake Units 7 and 8 will propose removing the annual emission limits in tons per year of both units to function as needed for other operational demands.

Files to accompany modeling results

Include the following files with the completed modeling report form. Use checkbox to indicate that all applicable files are included.

1. ☒ AERMOD input files (*.inp, *.adi, *.ami)
   ☒ AERMOD output files (*.out, *.ado, *.amo)
   ☒ AERMOD plot files (*.plt)
   ☐ AERMOD post files (*.pst) *(If applicable)*
   ☐ AERMOD event files (*.evi, *.evo) *(If applicable)*
   ☒ AERMOD miscellaneous/other files (MAXDCONT, .DAT, .emi, etc.) *(If applicable)*
2. AERMET files: ☒ *.sfc ☒*.pfl
3. BPIP-PRIME files: ☒ Input (*.bpi) ☒ Output (*.bpo, *.sum) *(If applicable)*
4. AERMAP files: ☐ Terrain (*.dem(s), *.tif [NED files]), ☐ Input (*.ami), ☒ Output (*.rou, *.sou, etc.) *(If applicable)*
5. Background data files: ☐ Background concentrations for applicable pollutants (seasonal, monthly, daily, hourly, etc.) *(If applicable)*
6. Modeling results: ☒ Figures (*.jpeg, *.pdf), ☐ GIS Maps (*.shp)
7. AQDM-02 spreadsheet: ☒ *(Provide the final spreadsheet [i.e., AQDM-02] and indicate/highlight changes.)*
8. Paved roads results: ☒ *(If applicable)*
9. SIL analysis and results: ☒ *(If applicable)*
10. Hourly O_3 file: ☒ *(If applicable)*
11. AERA forms: ☐ *(If applicable)*
12. Other files and supporting documents (paved roads fugitive dust modeling output files, etc.):

    Figure 1 NO2 1-Hour NAAQS Results; Figure 2 PM2.5 24-Hour NAAQS Results; Figure 3 PM2.5 Annual NAAQS Results; Figure 4 PM2.5 24-Hour Increment Results; Figure 5 PM2.5 Annual Increment Results; README_XBL_20231027.txt; XcelBlueLake_v10Results_20230928.xlsx; AQDM-05 Comments and Report Updates.xlsx; CertainTeed.zip; Koda Energy.zip; Anchor Glass.zip; Updated Emissions Inventory Data_20231012.xlsx; Updated Equipment Information_20231012.xlsx; FW_ Blue Lake Air Emissions.msg; RE_ Blue Lake Air Emissions.msg; Increment MPCADRAFT Spreadsheet (XcelBlueLake2022Project) 20231002.xls; Xcel_Blue_Lake_Conv_Proj_Emiss_Inv_post-protocolcomments20230908.xls; aq2-201_Xcel-Blue_Lake.doc; AQDM-04.PDF; AQDM-05.PDF

Section 1. Modeling protocol

1. The Air Dispersion Modeling presented in this report is based on a protocol that has been:
   ☐ Approved ☒ Conditionally approved ☐ *MPCA approval date (mm/dd/yyyy): 09/26/2023
   **This is the date given on AQDM-04 form*
2. Does this modeling submittal **completely** follow the approved protocol? ☐ Yes ☒ No
   If yes, proceed to Section 3.
   If no, proceed to Section 2.

Section 2. Changes to approved/conditionally approved modeling protocol

Table 1: Protocol changes (Please indicate which sections in the approved/conditionally approved protocol have been changed.)

Modeling protocol by sections	
Section name	**Change/No change**
Modeling purpose	No Change
Terrain	No Change
Buildings	No Change
Model selection and options	No Change
Point sources	No Change
Volume sources	Change
Area sources	No Change
Area source coordinates	No Change
Paved roads fugitive dust	Change
Receptors	Change
Meteorological data	No Change
Area of impact analysis	Change
Background values	No Change

Nearby sources	Change
Pollutant based considerations	No Change
Attachments	Change
AERA forms	No Change

Section 2.1: Detailed changes to modeling protocol

Please provide specific information corresponding to those sections in Table 1 where changes are indicated.

Modeling purpose

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Terrain

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Buildings

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Model selection and options

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Point sources

MPCA approved change: ☒ Yes ☐ No Date (mm/dd/yyyy): 10/04/2023

Describe changes:

To address MPCA's protocol question in section "AQDM-02 Form" about why the STRU12 (turbine 7) and STRU13 (turbine 8) project annual emission increases (due to strictly an annual limit removal, not a physical change) were not included in the SIL modeling analysis, these existing stacks were included in the SIL modeling for the annual standards only. As stated in the project description, Blue Lake Units 7 and 8 will propose removing the annual emission limits in tons per year on both units to function as needed for other operational demands. These annual limits were to maintain the facility below the major source significant emission rates, so the project emission change for STRU12 and STRU13 would be the increase in annual TPY from the previous limit to the now unconstrained annual limit. The SIL modeling for annual PM10, NOX, and PM2.5 was updated to include STRU12 and STRU13 annual project emissions increases. In addition, to improve clarity in AQDM-02, the Point Source Parameters tab was updated to identify which pollutants STRU12 and STRU13 were included in for modeling purposes and which were left out due to their project emissions only being on an annual basis.

Volume sources

MPCA approved change: ☒ Yes ☐ No Date (mm/dd/yyyy): 10/04/2023

Describe changes:

To address MPCA's protocol comments on the need to include paved road fugitive dust emissions from fuel delivery vehicles for the new project engines, the AQDM-02 spreadsheet with this final report includes a line of volume sources (PVRD001 - PVRD066) representing the delivery truck route within the fence line. The paved road volume sources were added to the PM10 and PM2.5 SIL modeling and the PM2.5 NAAQS and increment total facility modeling. The volume sources were spaced every 10 meters and the release height was based off of a typical fuel delivery truck. The emission rate calculations reflect the number of trips it would require to supply all three engines with enough Ultra Low Sulfur Diesel (ULSD) fuel to operate for 8,760 hours per year.

Area sources

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Area source coordinates

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Paved roads fugitive dust

MPCA approved change: ☒ Yes ☐ No Date (mm/dd/yyyy): 10/04/2023

Describe changes:

As stated in the Volume Source section, to address MPCA's protocol comments on the need to include paved road fugitive dust emissions from fuel delivery vehicles for the new project engines, the AQDM-02 spreadsheet with this final report includes a line of volume sources (PVRD001 - PVRD066) representing the delivery truck route within the fence line. The paved road volume sources were added to the PM10 and PM2.5 SIL modeling and the PM2.5 NAAQS and increment total facility modeling. The volume sources were spaced every 10 meters and the release height was based off of a typical fuel delivery truck. The emission rate calculations reflect the number of trips it would require to supply all three engines with enough Ultra Low Sulfur Diesel (ULSD) fuel to operate for 8,760 hours per year.

Receptors

MPCA approved change: ☒ Yes ☐ No Date (mm/dd/yyyy): 10/04/2023

Describe changes:

With the addition of the paved road project emissions and the existing combustion turbine 7 and 8 annual emissions increases in the SIL modeling, the PM2.5 24 hour and annual SIA receptors changed from the original protocol submittal. The PM2.5 24-hour and annual receptors evaluated for their respective NAAQS and increments has been updated and is included in the report supplemental files as "XcelBlueLake_PM25_24hrSIArecep.ROU" and "XcelBlueLake_PM25_AnnualSIArecep.ROU".

Meteorological data

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Area of impact analysis

MPCA approved change: ☒ Yes ☐ No Date (mm/dd/yyyy): 10/04/2023

Describe changes:

With the addition of the paved road project emissions and the existing combustion turbine 7 and 8 annual emissions increases in the SIL modeling, the annual NOx, 24-hour/annual PM10, and 24-hour/annual PM2.5 SIL maximum modeled results changed. The conclusions of the SIL modeling from the original protocol submittal stayed consistent with only 1-hour NO2 and 24-hour and annual PM2.5 requiring the cumulative analysis for NAAQS (PM2.5 and NOx) and increment (PM2.5). The updated SIL results are reflected in Table 5 below and the updated SIL Results form AQDM-11 is included in the supplemental files of this report.

Background values

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Nearby sources

MPCA approved change: ☒ Yes ☐ No Date (mm/dd/yyyy): 10/04/2023

Describe changes:

To address MPCA comments on the nearby source inventory for the NAAQS and increment analysis, the following updates have been made.

1. Koda Energy has been added to the PM2.5 increment analysis

2. CertainTeed and Anchor Glass 1 hour NOX NAAQS and 24 hour/annual PM2.5 Increment and NAAQS modeling inputs were updated using MPCA supplied most current available data.

3. Blue Lake WWTP NOX emissions were updated to reflect its Registration Permit 50 TPY NOX limit and the source information for the stack parameters was included in the supplemental files.

4. MPCA's increment inventory spreadsheet was updated to follow the MPCA's recommended approach of past actual emissions (2012-2013) at the minor source baseline date for all sources at a facility and current actuals (2020-2021) for all sources at a facility. MPCA provided past actuals data from Tempo for Rahr Malting, Xcel Blue Lake, Anchor Glass, Koda Energy, and CertainTeed.

Pollutant based considerations

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Attachments

MPCA approved change: ☒ Yes ☐ No Date (mm/dd/yyyy): 10/04/2023

Describe changes:

The following attachments from the previously submitted modeling protocol have been updated to reflect the changes described in the previous sections of this form: CertainTeed.zip; Koda Energy.zip; Anchor Glass.zip; Increment MPCADRAFT Spreadsheet (XcelBlueLake2022Project) 20231002.xls; Xcel_Blue_Lake_Conv_Proj_Emiss_Inv_post-protocolcomments20230908.xls; aq2-201_Xcel-Blue_Lake.doc; aq2-201_Xcel-Blue_Lake.doc.

The following files were not provided in the original protocol submittal, but address comments from MPCA on the conditionally approved protocol: FW_ Blue Lake Air Emissions.msg; RE_ Blue Lake Air Emissions.msg; Updated Emissions Inventory Data_20231012.xlsx; Updated Equipment Information_20231012.xlsx

AERA forms

MPCA approved change: ☐ Yes ☐ No Date (mm/dd/yyyy): _____

Describe changes:

Section 3. Paved roads fugitive dust (Optional)

Facilities that have indicated in their e-Services submittal the exclusion of paved roads in the air dispersion modeling should provide the results of that modeling in Table 1. Results should **not** include fugitive dust from paved roads.

Table 1: Model results for paved roads fugitive dust exemption policy. (See tables 2 and 3 for categories and requirements)

	Averaging period	NAAQS (µg/m³)	Total modeled NAAQS concentration (includes Background and Nearby Sources) (ug/m³)	% of NAAQS	PSD Class II increments (µg/m³)	Modeled class II increment impact concentrations (µg/m³)	% of Class II increments
PM_{10}	24-hour	150		0.00%	30		0.00%
	Annual	-	-	-	17		0.00%
$PM_{2.5}$	24-hour	35		0.00%	9		0.00%
	Annual	12		0.00%	4		0.00%

Table 2:

	NAAQS				PSD Class II increments			
	NAAQS/MAAQS result(s) w/	Cat. 1	Cat. 2	Cat. 3	*PSD Class II result(s) (%)*	Cat. 1	Cat. 2	Cat. 3

	background and nearby sources (%)							
PM_{10}	**!Undefined Bookmark, TEXT190**	*# < 60%*	*60% < # < 95%*	*95% < #*	0.00%	*# < 35%*	*35% < # < 75%*	*75% < #*
$PM_{2.5}$	0.00%	*# < 80%*	*80% < # < 95%*	*95% < #*	0.00%	*# < 40%*	*40% < # < 80%*	*80% < #*

Table 3:

Cat 1:	Paved road fugitive emissions not required to be modeled, and no paved road fugitive dust permit conditions. Requirements in Minn. R. 7011.150 apply.
Cat 2:	Paved road fugitive emissions not required to be modeled, with paved road fugitive dust permit conditions determined by levels of traffic at the facility.
Cat 3:	Paved road fugitive emissions **are** required to be modeled, with site-specific paved road fugitive dust permit conditions. Re-modeling and/or addition of paved road fugitive emissions source group required.

Section 4. Modeling results

Table 2: Pollutants and averaging periods (Check all the boxes for each pollutant and averaging period(s) modeled.)

Pollutant	Averaging period	Standard		Increment	SIL
		NAAQS	MAAQS		
CO	1-hr	☐	☐	☐	☒
	8-hr	☐	☐	☐	☒
Lead	Rolling 3 mo. Avg	☐	☐	☐	☐
	Quarterly Avg	☐	☐	☐	☐
NO_2	1-hr	☒	☐	☐	☒
	Annual	☐	☐	☐	☒
SO_2	1-hr	☐	☐	☐	☐
	3-hr	☐	☐	☐	☐
	24-hr	☐	☐	☐	☐
	Annual	☐	☐	☐	☐
PM_{10}	24-hr	☐	☐	☐	☒
	Annual	-	-	☐	☒
$PM_{2.5}$	24-hr	☒	☐	☒	☒
	Annual	☒	☐	☒	☒

Table 3: NAAQS/MAAQS modeling results (Enter modeling results along with the percent of standard.)

Pollutant	Averaging period	NAAQS standard (ug/m^3)	MAAQS standard (ug/m^3)	Total modeled concentration (includes background and nearby sources) (ug/m^3)	Percent of standard (%)	
					NAAQS	MAAQS
CO	1-hr	40,071.5	40,071.5			
	8-hr	10,304.1	10,304.1			
Lead	Rolling 3 mo. Avg	0.15	0.15			
NO_2	1-hr	188.0	188.0	95.8	51	51
	Annual	99.7	99.7			
SO_2	1-hr	196.4	196.4			
	3-hr	1309.3	1309.3			
	24-hr	366.6	366.6			
	Annual	78.6	78.6			
PM_{10}	24-hr	150.0	150.0			

$PM_{2.5}$	24-hr	35.0	35.0	30.4	87	87
	Annual	12.0	12.0	8.1	68	68

Table 4: Increment modeling results (Provide the increment modeling results along with the percent of standard.)

Pollutant	Averaging period	Class II increment (ug/m^3)	Total modeled concentration (includes other increment sources) (ug/m^3)	Percent of standard (%)
NO_2	1-hr	-	-	-
	Annual	25		
SO_2	1-hr	-	-	-
	3-hr	512		
	24-hr	91		
	Annual	20		
PM_{10}	24-hr	30		
	Annual	17		
$PM_{2.5}$	24-hr	9	3.7	41
	Annual	4	0.40	10

Table 5: SIL modeling results (Provide the SIL modeling results along with the percent of standard.)

Pollutant	Averaging period	SIL (ug/m^3)	Total modeled concentration (ug/m^3)	Percent of standard (%)
NO_2	1-hr	7.52	27.2	363
	Annual	1	0.86	86
SO_2	1-hr	7.86		
	3-hr	25		
	24-hr	5		
	Annual	1		
PM_{10}	24-hr	5	4.6	92
	Annual	1	0.32	32
$PM_{2.5}$	24-hr	1.2	3.3	275
	Annual	0.3	0.28	139
CO	1-hr	2000	13	1
	8-hr	500	8	2

Section 5. Discussion

Enter any discussion or comments on the information provided in this form (this can be used as a substitute for a written report):

The NAAQS results in Table 3 include the 1-hour NO2 background concentration values from the Lakeville, MN NO2 monitor (2019-2021 98th percentile) and the 24-hour and annual background concentrations from values from the Shakopee, MN PM2.5 monitor (2019-2021 98th percentile and annual maximum). The Xcel Blue Lake project's indirect PM2.5 emissions contribution to the NAAQS was added directly to the PM2.5 background concentration using EPA's MERP calculation methodology and the post-project NOX and SO2 potential emissions. That contribution is calculated in tab "O3 & PM2.5 Precursor Evaluation" of the AQDM-02 emission inventory submitted with this report.

The increment results in Table 4 include the indirect PM2.5 concentrations from all modeled increment sources' NOx and SO2 emissions using the EPA MERP calculation methodology. The tab "Precursor MERP calc" in the spreadsheet "Increment MPCADRAFT Spreadsheet (XcelBlueLake2022Project) 20231002.xlsx.xls" contains the downloaded actual NOx and SO2 emissions for 2020-2021 for Rahr Malting, CertainTeed, Anchor Glass, and Koda Energy and the calculation of their PM2.5 contributions to the contemporaneous actuals. The individual facility concentrations were summed and then added directly to the modeled direct PM2.5 increment results.

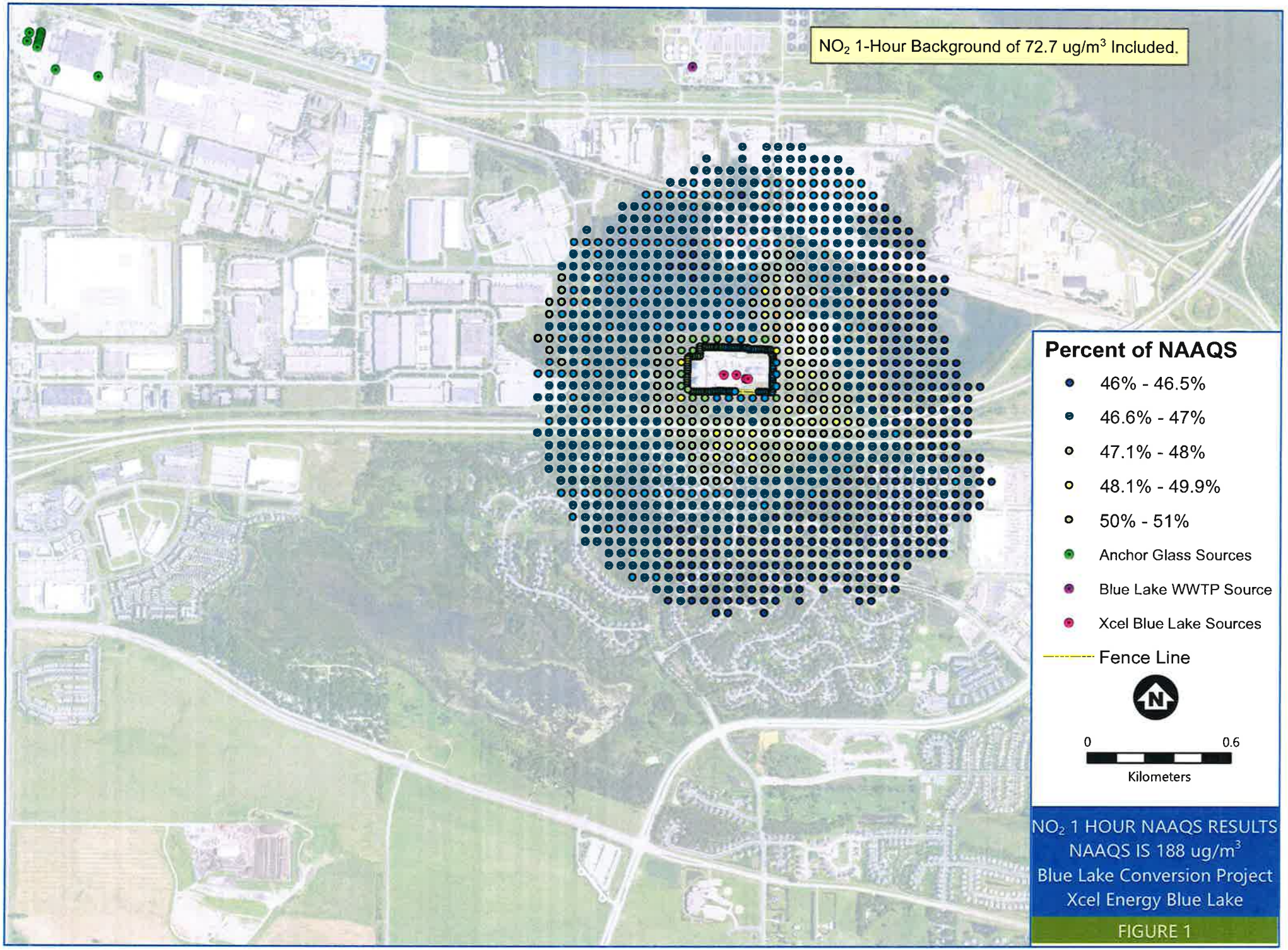
The Xcel Energy Blue Lake supplemental modeling files are included with this submittal in the zip file Xcel-BlueLake2022ConversionProject_SupplementalModelingReportFiles.zip.

Section 6. Modeling results figures/maps

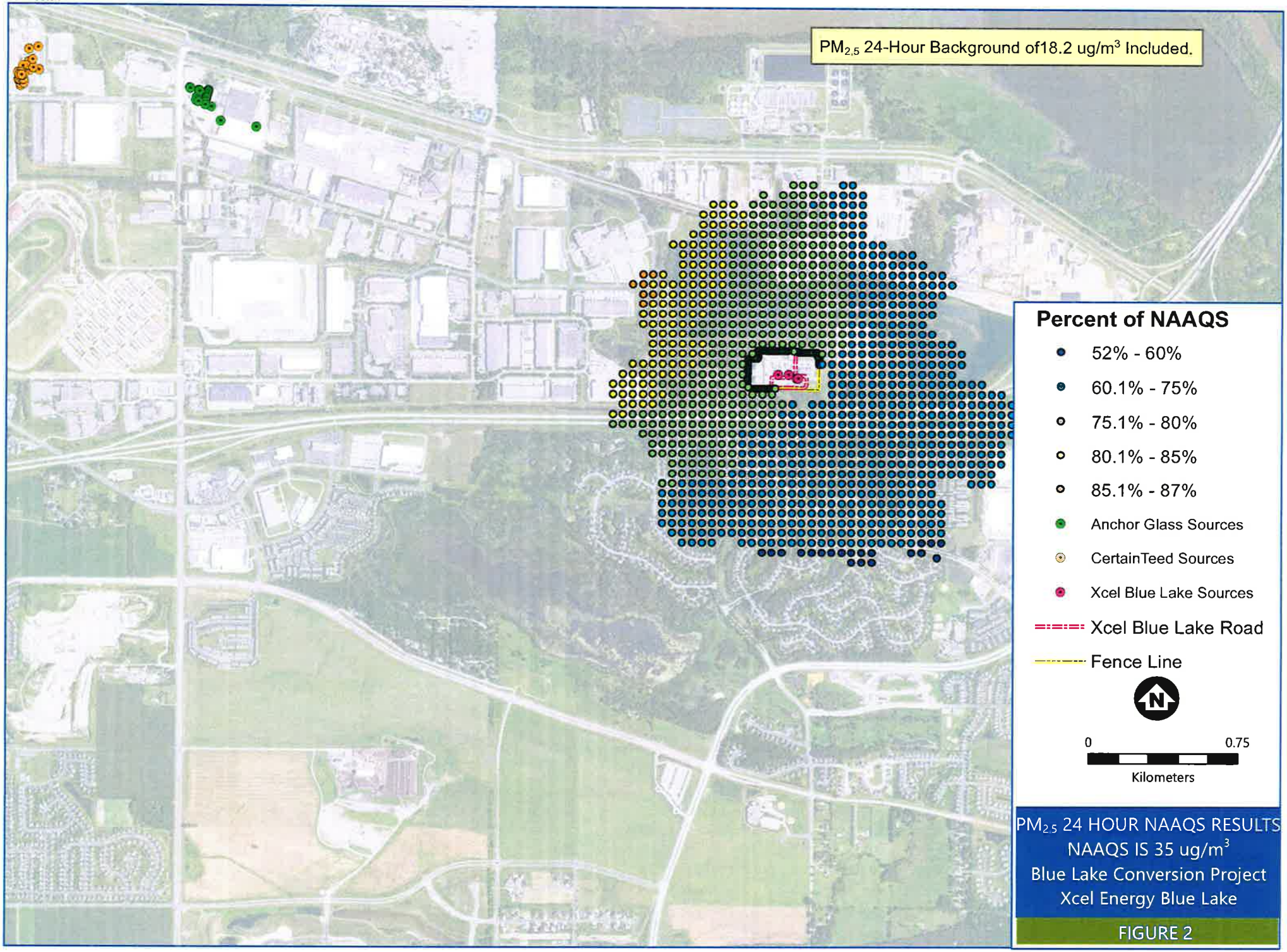
Insert a figure or map showing the facility emission sources, receptors, and the location of the modeled maximum concentration(s) for each applicable pollutant, corresponding averaging periods, and operating scenarios.

[Paste here]

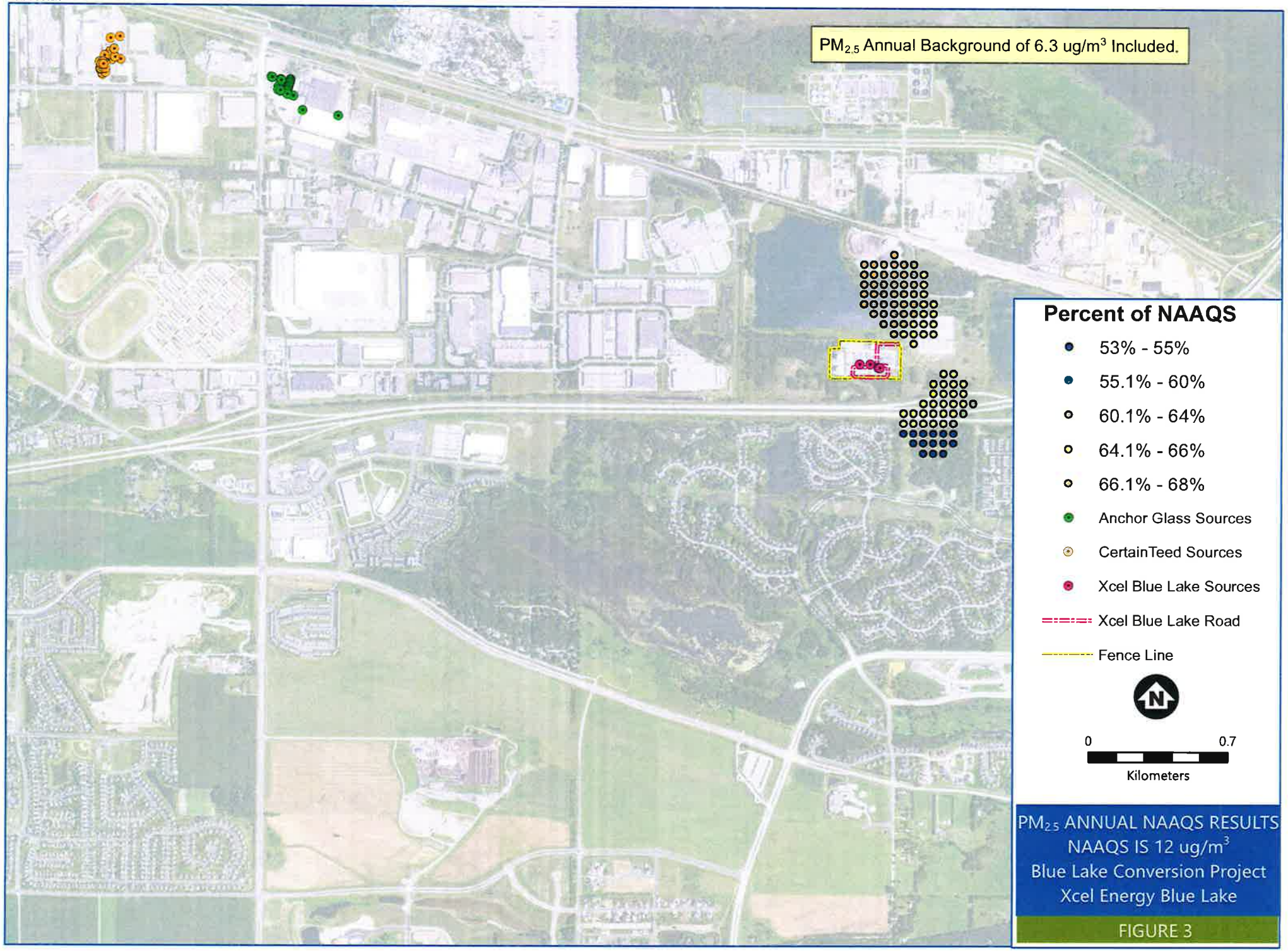
Barr Footer:


NO_2 1-Hour Background of 72.7 ug/m^3 Included.
Percent of NAAQS
46% - 46.5%
46.6% - 47%
47.1% - 48%
48.1% - 49.9%
50% - 51%
Anchor Glass Sources
Blue Lake WWTP Source
Xcel Blue Lake Sources
Fence Line
N
0
0.6
Kilometers
NO_2 1 HOUR NAAQS RESULTS
NAAQS IS 188 ug/m^3
Blue Lake Conversion Project
Xcel Energy Blue Lake
FIGURE 1

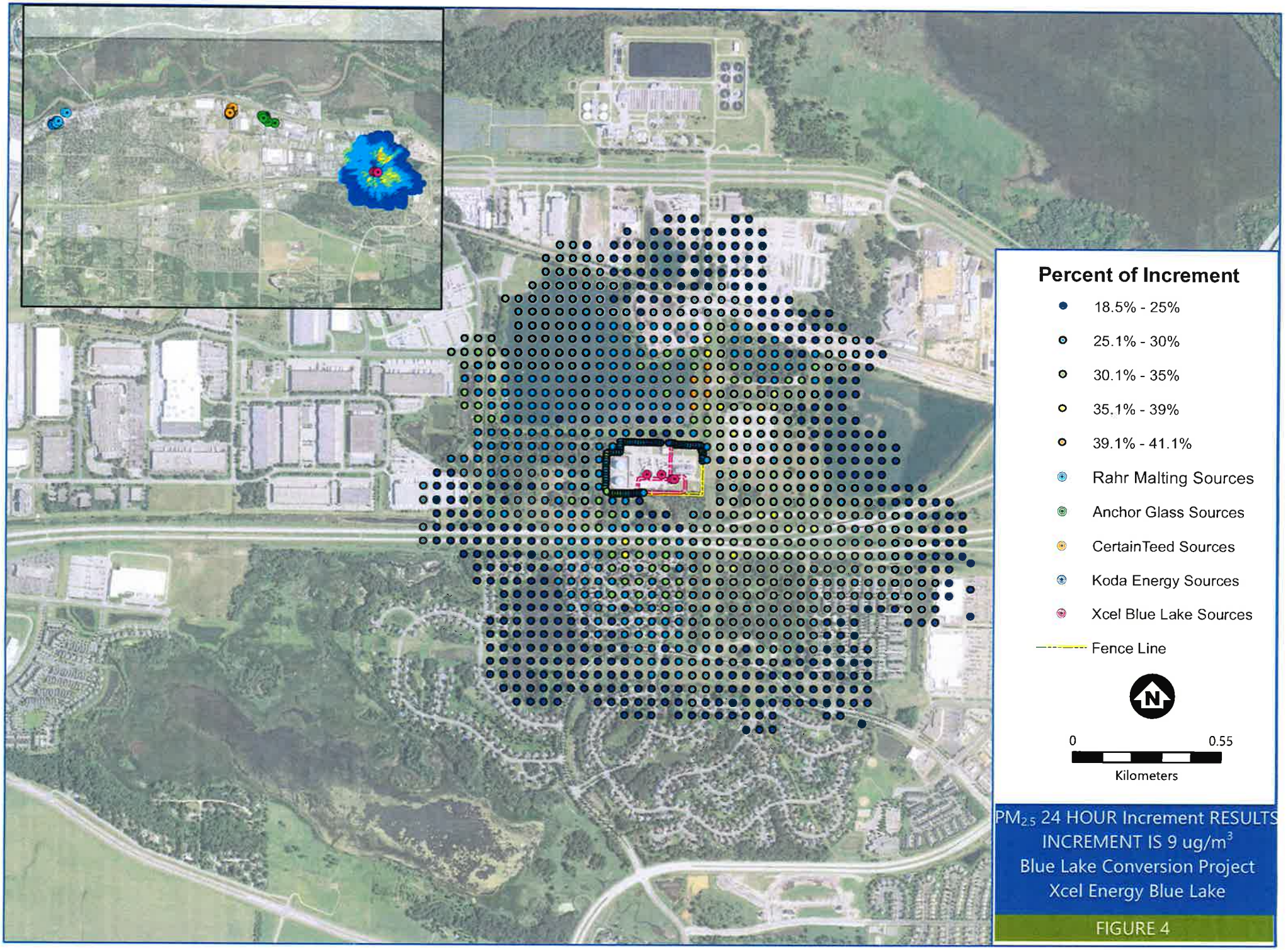
Barr Footer:

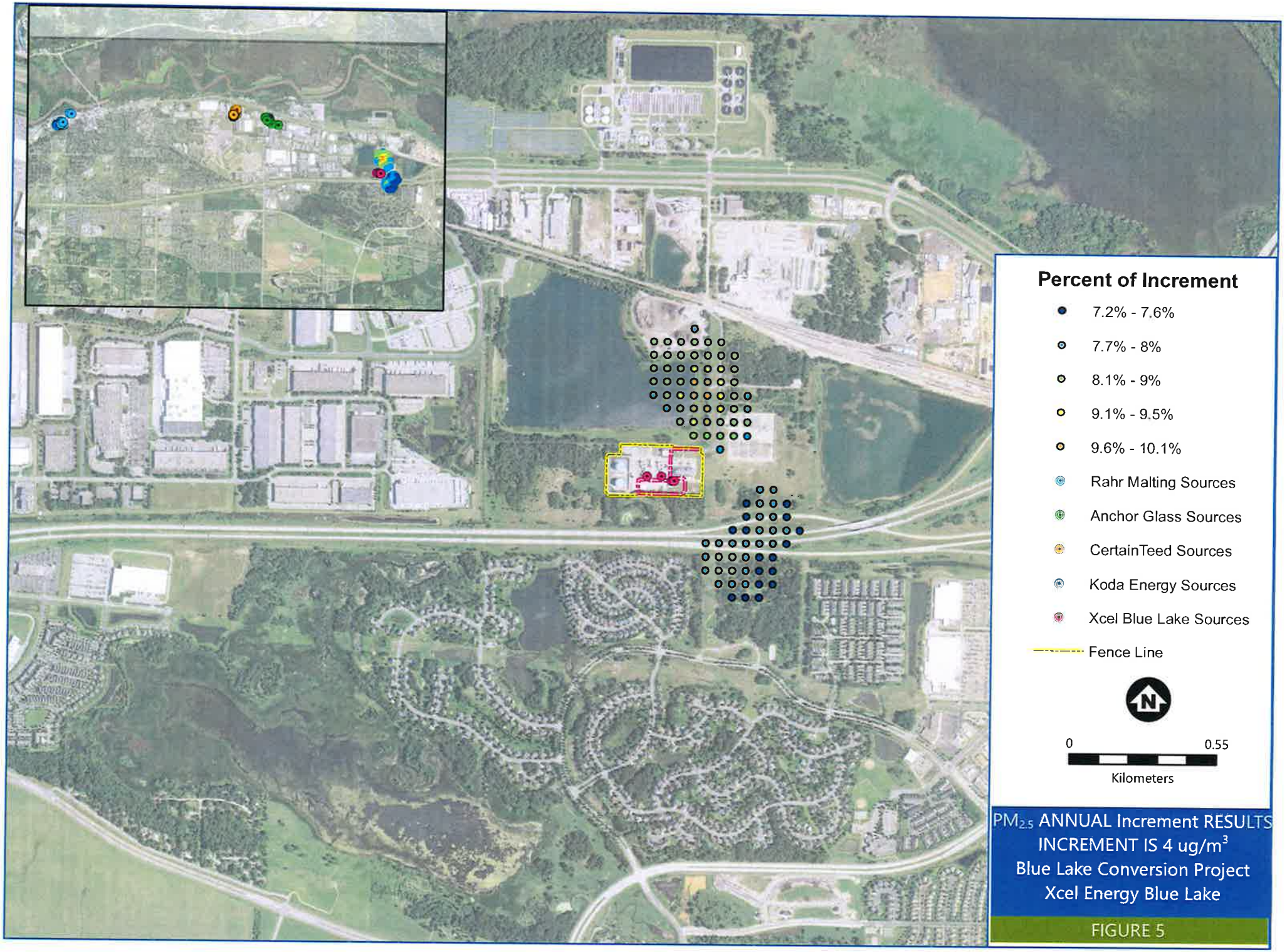

PM2.5 24-Hour Background of18.2 ug/m3 Included.
Percent of NAAQS
52% - 60%
60.1% - 75%
75.1% - 80%
80.1% - 85%
85.1% - 87%
Anchor Glass Sources
CertainTeed Sources
Xcel Blue Lake Sources
Xcel Blue Lake Road
Fence Line
N
0
0.75
Kilometers
PM2.5 24 HOUR NAAQS RESULTS
NAAQS IS 35 ug/m3
Blue Lake Conversion Project
Xcel Energy Blue Lake
FIGURE 2

Barr Footer:


$PM_{2.5}$ Annual Background of 6.3 ug/m^3 Included.
Percent of NAAQS
53% - 55%
55.1% - 60%
60.1% - 64%
64.1% - 66%
66.1% - 68%
Anchor Glass Sources
CertainTeed Sources
Xcel Blue Lake Sources
Xcel Blue Lake Road
Fence Line
N
0
0.7
Kilometers
$PM_{2.5}$ ANNUAL NAAQS RESULTS
NAAQS IS 12 ug/m^3
Blue Lake Conversion Project
Xcel Energy Blue Lake
FIGURE 3

Barr Footer:


Percent of Increment
18.5% - 25%
25.1% - 30%
30.1% - 35%
35.1% - 39%
39.1% - 41.1%
Rahr Malting Sources
Anchor Glass Sources
CertainTeed Sources
Koda Energy Sources
Xcel Blue Lake Sources
Fence Line
N
0
0.55
Kilometers
PM2.5 24 HOUR Increment RESULTS
INCREMENT IS 9 ug/m3
Blue Lake Conversion Project
Xcel Energy Blue Lake
FIGURE 4



$PM_{2.5}$ ANNUAL Increment RESULTS
INCREMENT IS 4 ug/m^3
Blue Lake Conversion Project
Xcel Energy Blue Lake

FIGURE 5

Attachment 5 - Manufacturer Guarantees

FORM OF CHANGE ORDER REQUEST

THIS CHANGE ORDER REQUEST NO. 01 TO THE RECIPROCATING INTERNAL COMBUSTION ENGINE (RICE) AND ACCESORIES SUPPLY AGREEMENT EFFECTIVE AS OF NOVEMBER 1, 2022, ("AGREEMENT") BY AND BETWEEN NORTHERN STATES POWER COMPANY ("COMPANY") AND Wärtsilä NORTH AMERICA, INC. ("SUPPLIER") IS EFFECTIVE AS OF [TODAYS DATE] AND CONSISTS OF THE FOLLOWING:

SUBJECT: Revisions to Schedules A, D, D.1, & G

SCOPE OF WORK MODIFICATIONS: N/A

FIXED PRICE MODIFICATION: $0.00

GUARANTEED COMPLETION DATE MODIFICATIONS: N/A

MILESTONE SCHEDULE MODIFICATIONS: N/A

WORK SCHEDULE MODIFICATIONS: N/A

PERFORMANCE GUARANTEE MODIFICATIONS: See next page

RELIABILITY GUARANTEE MODIFICATIONS: N/A

OTHER AGREEMENT MODIFICATIONS: See next page

By signing its Change Order Request proposal, Consultant agrees that the performance of the work described in this Request for Change Order Proposal can be accomplished concurrently with the Work under the Contract / Agreement, as modified by all Change Orders preceding this Request for Change Order Proposal. Consultant acknowledges and confirms that all cost, direct and indirect, associated with the work (and the time period for performance of such work) agreed to herein, including all costs incurred for overhead, supervision, disruption or suspension of work, labor inefficiencies, and this Request for Change Order Proposal's impact on unchanged Work are completely documented and contained in Consultant's Change Order Request Price Proposal.

In consideration of the changes agreed to herein as complete equitable adjustment(s) for the matters included in Consultant's Change Order Request Price Proposal, Consultant hereby waives any right to claim by means of a separate Change Order Request or cumulative impact claim, and forever releases Company from any and all liability for, further adjustments (equitable or otherwise) to the Work or to any terms or conditions of the Agreement attributable to the facts and circumstances giving rise to this Request for Change Order Request referenced above.

EXCEPT AS SPECIFICALLY SET FORTH HEREIN, ALL OTHER TERMS AND CONDITIONS OF THE AGREEMENSHALL REMAIN IN FULL FORCE AND EFFECT.

REQUESTED
SUPPLIER:

BY: Wärtsilä North America, Inc.

Greg Bosley
Printed Name of requesting individual


(SIGNATURE)

2023-05-01
(DATE)

PERFORMANCE GUARANTEE MODIFICATIONS:

- Replace Schedule D Table 101-2 with updated VOC and PM emissions values and definitions as marked up and attached.
- Replace Schedule D.1 section 1.09.H.4 with updated test methods as marked up and attached.

OTHER AGREEMENT MODIFICATIONS:

- Replace Schedule A Appendix 48 60 12-A Tables 48 60 12-A1 and 48 60 12-A2 with updated predicted VOC emissions data as marked up and attached.
- Replace Schedule G section 103 with updated fuel specification references in section 103 as marked up and attached.

Table 101-2

Emission Guarantees at 100% Load – BLUE LAKE & WHEATON

Emission Values for Normal Operation with Catalyst			
Pollutant [A]	**Units**	**100% Load Guarantee [B] Natural Gas Fired**	**100% Load Guarantee [B] Fuel Oil Fired**
NOx	g/kWe	0.08	0.53
CO	g/kWe	0.12	0.18
VOC (as C_3H_8)	g/kWe	~~0.015~~ 0.15[E]	0.22
$PM_{2.5}$ / PM_{10} [C]	g/kWe	0.10[C]	~~0.22~~ 0.15[D]
CO_2	g/kWe	-	-
CH_2O	g/kWe	0.006	-
Acrolein	g/kWe	0.016	-
Acetaldehyde	g/kWe	0.013	-
Methanol	g/kWe	0.007	-
Flow Stack	Nm^3/s dry	10.5	13.1
Reference	O_2% dry		
Gas Consumption	scfh	Refer to Heat Rate Table 101a & 101b	Refer to Heat Rate Table 101a & 101b
Output Mech	BHP-gross	12,861	12,675 / 12,674
Output	kWe-gross	9,370	9,233 / 9,232

Notes:

(A) Controls - oxidation catalyst and SCR using NH3 or urea

(B) 100% load values are to be provided as guarantees

(C) Filterable plus condensable

(D) Filterable

(E) Guarantee applies for fuel gas VOC concentrations <1.0 mol-%. For fuel gas VOC concentrations between 1.0 mol-% and 1.8 mol-% guarantee is 0.17 g/kWe

a. USA EPA Method 18: Measurement of gaseous organic compound emissions by gas chromatography. VOC is calculated as the sum of relevant components, which for a gas engine equipped with a high efficiency catalyst are considered to be: propane, n-butane, n-pentane, n-hexane, n-heptane, n-octane, and benzene.

4. $PM_{2.5}$ / PM_{10} (total)
   a. Total $PM_{2.5}$ / PM_{10} is defined as the sum of the particulate matter measured with a combination of EPA 201A or ~~17~~ 5 and 202 methods.
      (1) USA EPA Method 201A or Method 5 (front half): Determination of filterable $PM_{2.5}$ / PM_{10} emissions (in-stack filter method with sizing device). All emitted PM can be assumed to be PM2.5. Supplier can use EPA Method 5 in combination with EPA Method 202.
      (2) USA EPA Method 202 Determination of condensable particulate matter from stationary sources.
5. Formaldehydes (CH_2O)
   a. US EPA Method 320: Vapor Phase Organic and Inorganic Emissions by Extrative FTIR or US EPA Method 323.
6. Ammonia slip (NH_3)
   a. US EPA Method CTM-027: Procedure for collection and analysis of ammonia in stationary sources or US EPA Method 320.

I. The following constituents will not require performance testing:
   1. CO_2
   2. Acrolein
   3. Acetaldehyde
   4. Methanol

1.10 FUNCTIONAL PERFORMANCE TESTS:

A. Reagent Consumption Test:
   1. Net flow of emissions control reagent to each SCR unit shall be measured by the calibrated injection system for the reagent by separate flow meters concurrently with the Thermal Performance Test.
   2. Reagent consumption shall be corrected for the concentration of the solution being used, if required.

B. Lube Oil Consumption Test:
   1. Consumption of lube oil by each engine will be measured over the first 100 hours of unit performance by measuring the oil level in the engine sump immediately after first fire and again after 96 hours of operation. Any oil added during this time shall be considered as consumed and shall be appropriately measured.

C. Part Load Stable Operation Test (MECL test):
   1. Supplier shall demonstrate the genset's capability to operate in a stable condition (less than 2% deviation in net unit electrical output without operator intervention) and in accordance with the Guaranteed Emissions for four continuous hours at Minimum Emissions Compliance Load (MECL).
   2. Genset shall be in compliance with the Maximum Emissions Guarantees as demonstrated by concurrent emissions testing.

D. Startup Reliability Test:

Appendix 48 60 12-A1
RICE Emission Data - BLUE LAKE (BLL)
Expected Emissions (Controlled) when operating off Natural Gas and Fuel Oil

Natural Gas Operation

BLL Natural Gas - Treated Emissions

Treated Emission Summary & Conversion Tables

Applicable to one engine (steady state) (Not an average over all engines)

		100%	90%	75%	50%	40%	Minimum Emissions Compliance* 40%
NOx (as NO2)	**ppm-v, 15 % O2, dry**	6	6	6	9	9	
CO	**ppm-v, 15 % O2, dry**	15	15	15	15	15	
VOC (as CH4) **	**ppm-v, 15 % O2, dry**	33.8	33.8	33.8	48.1	54.6	
VOC (as C3H8) **	**ppm-v, 15 % O2, dry**	11.3	11.3	11.3	16.0	18.2	
Ammonia	**ppm-v, 15 % O2, dry**	10	10	10	10	10	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**g/kWhe**	0.08	0.08	0.09	0.14	0.15	
CO	**g/kWhe**	0.12	0.12	0.13	0.14	0.15	
VOC (as CH4) **	**g/kWhe**	0.16	0.16	0.17	0.25	0.30	
VOC (as C3H8) **	**g/kWhe**	0.15	0.15	0.15	0.23	0.27	
PM10 (Total Front/back half)	**g/kWhe**	0.10	0.10	0.10	0.15	0.16	
PM2.5 (Total Front/back half)	**g/kWhe**	0.10	0.10	0.10	0.15	0.16	
Ammonia	**g/kWhe**	0.05	0.05	0.05	0.06	0.06	
CO2	**g/kWhe**	440	445	461	497	512	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**lb/hr**	1.65	1.51	1.33	1.41	1.19	
NOx (as NO2)	**lb/mmbtu**	0.0236	0.0236	0.0235	0.0345	0.0338	
CO	**lb/hr**	2.51	2.30	2.02	1.43	1.2	
CO	**lb/mmbtu**	0.0359	0.0359	0.0357	0.0350	0.0343	
VOC (as CH4) **	**lb/hr**	3.26	2.97	2.56	2.62	2.45	
VOC (as C3H8) **	**lb/mmbtu**	0.0425	0.0424	0.0423	0.0590	0.0655	
PM10 (Total Front/back half)	**lb/hr**	2.01	1.84	1.62	1.53	1.29	
PM10 (Total Front/back half)	**lb/mmbtu**	0.0288	0.0287	0.0286	0.0374	0.0366	
PM2.5 (Total Front/back half)	**lb/hr**	2.01	1.84	1.62	1.53	1.29	
PM2.5 (Total Front/back half)	**lb/mmbtu**	0.0288	0.0287	0.0286	0.0374	0.0366	
Ammonia	**lb/hr**	1.02	0.93	0.82	0.58	0.49	
Ammonia	**lb/mmbtu**	0.0146	0.0146	0.0145	0.0142	0.0139	
CO2	**lb/mmBtu**	129.4	129.2	128.8	126.3	123.5	
	pounds per hour per engine						
Formaldehyde	**lb/hr**	0.126	0.115	0.099	0.110	0.102	
Formaldehyde	**lb/mmBtu**	0.00180	0.00179	0.00179	0.00271	0.00296	
Acrolein	**lb/hr**	0.337	0.307	0.265	0.294	0.271	
Acrolein	**lb/mmBtu**	0.00480	0.00479	0.00477	0.00723	0.00791	
Acetaldehyde	**lb/hr**	0.265	0.241	0.208	0.231	0.213	
Acetaldehyde	**lb/mmbtu**	0.00377	0.00376	0.00375	0.00568	0.00621	
Methanol	**lb/hr**	0.135	0.123	0.106	0.118	0.108	
Methanol	**lb/mmbtu**	0.00192	0.00192	0.00191	0.00289	0.00316	
Heat Input	**mmBtu/hr HHV**	77.7	70.9	61.4	44.9	37.9	
Output	kWe-gross	9,370	8,433	7,027	4,685	3,748	

mmBtu = one million British thermal units (1 Btu = 1,05506 kJ), LHV

*Please enter in the minimum emissions compliance load for permitting, along with emissions at that load

** For fuel gas VOC concentrations between 1.0 mol-% and 1.8 mol-%, multiply VOC emission values by 1.133 (note that fuel gas must be according to contract limits)

BLL Natural Gas - Start-up/Shutdown Emissions

Component	Emissions per Cold Start[A]	Emissions per Warm Start[B]	Emissions per Hot Start[C]	Emissions per Shutdown
	lb	lb	lb	lb
NO_x	14	11.5	9	0.03
Formaldeyde	1.48	0.18	0.06	0.002
CO	10.5	8.8	7.5	0.043
VOC as CH_4	3.22	1.79	1.6	0.05
VOC as C3H8	2.95	1.64	1.47	0.05
PM_{10}	2	2	2	0.034
PM2.5 (total)	2	2	2	0.034
CO_2	4547	4547	4547	152
Start-up Assumptions				
RICE Start-up duration (Hours)	30 min	30 min	30 min	
Shutdown Assumptions				
RICE Shutdown duration (Hours)				1 min

[A] A cold start is the engine has not operated in last 2-3 days

[B] Warm start is engine is restarted 6-12 hours after last shutdown

[C] Hot start is engine was shutdown in the last 6 hours

[D] starting to Gas mode means that engine preheating temperatures are 50 °C (122 °F). Engine will initially start on diesel mode and transfer to gas mode during the loading phase

[E] The VOC (volatile organic compounds) emissions depend on the composition of the fuel gas. The VOC emissions in table above are based on max 1 mol-% VOC components in the feed fuel gas and are NOT including CH2O.

BLL Natural Gas - Stack Information

	100%	90%	75%	50%	40%	MECL
Flue gas exit temperature (degrees F)	708.4	744.3	746.1	752.9	760.6	
Flue gas flow rate (acfm)	58703	55373	50489	40747	34731	
Flue gas exit velocity (ft/sec)						
Stack Diameter (ft)						

Fuel Oil (USDL) Operation

BLL Fuel Oil - Treated Emissions

Treated Emission Summary & Conversion Tables

Applicable to one engine (steady state) (Not an average over all engines)

		100%	90%	75%	50%	40%	Minimum Emissions Compliance* 40%
NOx (as NO2)	**ppm-v, 15 % O2, dry**	35	35	35	40	40	
CO	**ppm-v, 15 % O2, dry**	20	20	20	20	20	
VOC (as CH4)	**ppm-v, 15 % O2, dry**	40	40	40	40	40	
VOC (as C3H8)	**ppm-v, 15 % O2, dry**	13.33	13.33	13.33	13.33	13.33	
Ammonia	**ppm-v, 15 % O2, dry**	10	10	10	10	10	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**g/kWhe**	0.53	0.53	0.53	0.63	0.66	
CO	**g/kWhe**	0.18	0.18	0.19	0.19	0.2	
VOC (as CH4)	**g/kWhe**	0.21	0.21	0.21	0.22	0.23	
VOC (as C3H8)	**g/kWhe**	0.19	0.19	0.19	0.20	0.21	
PM10 (Total Front/back half)	**g/kWhe**	0.22	0.22	0.22	0.31	0.32	
PM2.5 (Total Front/back half)	**g/kWhe**	0.22	0.22	0.22	0.31	0.32	
Ammonia	**g/kWhe**	0.06	0.06	0.06	0.06	0.06	
CO2	**g/kWhe**	619	616	620	639	672	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**lb/hr**	10.86	9.62	8.22	6.43	5.36	
NOx (as NO2)	**lb/mmbtu**	0.1440	0.1439	0.1437	0.1643	0.1642	
CO	**lb/hr**	3.78	3.35	2.86	1.96	1.63	
CO	**lb/mmbtu**	0.0501	0.0501	0.0500	0.0500	0.0500	
VOC (as CH4)	**lb/hr**	4.33	3.83	3.28	2.24	1.87	
VOC (as C3H8)	**lb/mmbtu**	0.0526	0.0525	0.0525	0.0525	0.0525	
PM10 (Total Front/back half)	**lb/hr**	4.53	4.02	3.43	3.13	2.61	
PM10 (Total Front/back half)	**lb/mmbtu**	0.0601	0.0601	0.0600	0.0801	0.0800	
PM2.5 (Total Front/back half)	**lb/hr**	4.53	4.02	3.43	3.13	2.61	
PM2.5 (Total Front/back half)	**lb/mmbtu**	0.0601	0.0601	0.0600	0.0801	0.0800	
Ammonia	**lb/hr**	1.15	1.02	0.87	0.6	0.5	
Ammonia	**lb/mmbtu**	0.0152	0.0152	0.0152	0.0152	0.0152	
CO2	**lb/mmBtu**	171.5	171.5	171.4	171.1	171.0	
	pounds per hour per engine						
Formaldehyde	**lb/hr**	-	-	-	-	-	
Formaldehyde	**lb/mmBtu**	-	-	-	-	-	
Acrolein	**lb/hr**	-	-	-	-	-	
Acrolein	**lb/mmBtu**	-	-	-	-	-	
Acetaldehyde	**lb/hr**	-	-	-	-	-	
Acetaldehyde	**lb/mmbtu**	-	-	-	-	-	
Methanol	**lb/hr**	-	-	-	-	-	
Methanol	**lb/mmbtu**	-	-	-	-	-	
Heat Input	**mmBtu/hr HHV**	79.6	71.3	59.7	41.1	34.6	
Output	kWe-gross	9,370	8,433	7,027	4,685	3,748	

mmBtu = one million British thermal units (1 Btu = 1,05506 kJ), LHV

*Please enter in the minimum emissions compliance load for permitting, along with emissions at that load

BLL Fuel Oil - Start-up/Shutdown Emissions

Component	Emissions per Cold Start[A]	Emissions per Warm Start[B]	Emissions per Hot Start[C]	Emissions per Shutdown
	lb	lb	lb	lb
NO_x	45	36	32	0.2
Formaldeyde	-	-	-	-
CO	6	5.1	5	0.1
VOC as CH_4	2.5	2.15	1.8	0.1
VOC as C3H8	2.29	1.97	1.65	0.09
PM_{10}	5	5	5	0.05
PM2.5 (total)	5	5	5	0.05
CO_2	6398	6398	6398	213
Start-up Assumptions				
RICE Start-up duration (Hours)	30 min	30 min	30 min	
Shutdown Assumptions				
RICE Shutdown duration (Hours)				1 min

[A] A cold start is the engine has not operated in last 2-3 days

[B] Warm start is engine is restarted 6-12 hours after last shutdown

[C] Hot start is engine was shutdown in the last 6 hours

Wartsila estimates the emissions rates per engine at 10% load to be NOx as NO2 - 10 g/s, CO - 2 g/s, PM - 1 g/s, THC - 2 g,
Wärtsilä estimates the maximum emission rates at 25% load would be NOx as NO2 15 g/s, CO 2 g/s, PM 1 g/s, and THC 2

BLL Fuel Oil - Stack Information

	100%	90%	75%	50%	40%	MECL
Flue gas exit temperature (degrees F)	629	608	608	625	608	
Flue gas flow rate (acfm)	68281	62260	56967	54032	44250	
Flue gas exit velocity (ft/sec)						
Stack Diameter (ft)						

Appendix 48 60 12-A2
RICE Emission Data - WHEATON (WHT)
Expected Emissions (Controlled) when operating off Natural Gas and Fuel Oil

Natural Gas Operation

WHT Natural Gas - Treated Emissions

Treated Emission Summary & Conversion Tables

Applicable to one engine (steady state) (Not an average over all engines)

		100%	90%	75%	50%	40%	Minimum Emissions Compliance* 40%
NOx (as NO2)	**ppm-v, 15 % O2, dry**	6	6	6	9	9	
CO	**ppm-v, 15 % O2, dry**	15	15	15	15	15	
VOC (as CH4) **	**ppm-v, 15 % O2, dry**	33.8	33.8	33.8	48.1	54.6	
VOC (as C3H8) **	**ppm-v, 15 % O2, dry**	11.3	11.3	11.3	16.0	18.2	
Ammonia	**ppm-v, 15 % O2, dry**	10	10	10	10	10	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**g/kWhe**	0.08	0.08	0.09	0.14	0.15	
CO	**g/kWhe**	0.12	0.12	0.13	0.14	0.15	
VOC (as CH4) **	**g/kWhe**	0.16	0.16	0.17	0.25	0.30	
VOC (as C3H8) **	**g/kWhe**	0.15	0.15	0.15	0.23	0.27	
PM10 (Total Front/back half)	**g/kWhe**	0.10	0.10	0.10	0.15	0.16	
PM2.5 (Total Front/back half)	**g/kWhe**	0.10	0.10	0.10	0.15	0.16	
Ammonia	**g/kWhe**	0.05	0.05	0.05	0.06	0.06	
CO2	**g/kWhe**	440	445	461	497	512	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**lb/hr**	1.65	1.51	1.33	1.41	1.19	
NOx (as NO2)	**lb/mmbtu**	0.0236	0.0236	0.0235	0.0345	0.0338	
CO	**lb/hr**	2.51	2.30	2.02	1.43	1.2	
CO	**lb/mmbtu**	0.0359	0.0359	0.0357	0.0350	0.0343	
VOC (as CH4) **	**lb/hr**	3.26	2.97	2.56	2.62	2.45	
VOC (as C3H8) **	**lb/mmbtu**	0.0425	0.0424	0.0423	0.0590	0.0655	
PM10 (Total Front/back half)	**lb/hr**	2.01	1.84	1.62	1.53	1.29	
PM10 (Total Front/back half)	**lb/mmbtu**	0.0288	0.0287	0.0286	0.0374	0.0366	
PM2.5 (Total Front/back half)	**lb/hr**	2.01	1.84	1.62	1.53	1.29	
PM2.5 (Total Front/back half)	**lb/mmbtu**	0.0288	0.0287	0.0286	0.0374	0.0366	
Ammonia	**lb/hr**	1.02	0.93	0.82	0.58	0.49	
Ammonia	**lb/mmbtu**	0.0146	0.0146	0.0145	0.0142	0.0139	
CO2	**lb/mmBtu**	129.4	129.2	128.8	126.3	123.5	
	pounds per hour per engine						
Formaldehyde	**lb/hr**	0.126	0.115	0.099	0.110	0.102	
Formaldehyde	**lb/mmBtu**	0.00180	0.00179	0.00179	0.00271	0.00296	
Acrolein	**lb/hr**	0.337	0.307	0.265	0.294	0.271	
Acrolein	**lb/mmBtu**	0.00480	0.00479	0.00477	0.00723	0.00791	
Acetaldehyde	**lb/hr**	0.265	0.241	0.208	0.231	0.213	
Acetaldehyde	**lb/mmbtu**	0.00377	0.00376	0.00375	0.00568	0.00621	
Methanol	**lb/hr**	0.135	0.123	0.106	0.118	0.108	
Methanol	**lb/mmbtu**	0.00192	0.00192	0.00191	0.00289	0.00316	
Heat Input	**mmBtu/hr HHV**	77.7	70.9	61.4	44.9	37.9	
Output	kWe-gross	9,370	8,433	7,027	4,685	3,748	

mmBtu = one million British thermal units (1 Btu = 1,05506 kJ), LHV

*Please enter in the minimum emissions compliance load for permitting, along with emissions at that load

** For fuel gas VOC concentrations between 1.0 mol-% and 1.8 mol-%, multiply VOC emission values by 1.133 (note that fuel gas must be according to contract limits)

WHT Natural Gas - Start-up/Shutdown Emissions

Component	Emissions per Cold Start[A]	Emissions per Warm Start[B]	Emissions per Hot Start[C]	Emissions per Shutdown
	lb	lb	lb	lb
NO_x	14	11.5	9	0.03
Formaldeyde	1.48	0.18	0.06	0.002
CO	10.5	8.8	7.5	0.043
VOC as CH_4	3.22	1.79	1.6	0.05
VOC as C3H8	2.95	1.64	1.47	0.05
PM_{10}	2	2	2	0.034
PM2.5 (total)	2	2	2	0.034
CO_2	4547	4547	4547	152
Start-up Assumptions				
RICE Start-up duration (Hours)	30 min	30 min	30 min	
Shutdown Assumptions				
RICE Shutdown duration (Hours)				1 min

[A] A cold start is the engine has not operated in last 2-3 days

[B] Warm start is engine is restarted 6-12 hours after last shutdown

[C] Hot start is engine was shutdown in the last 6 hours

[D] starting to Gas mode means that engine preheating temperatures are 50 °C (122 °F). Engine will initially start on diesel mode and transfer to gas mode during the loading phase

[E] The VOC (volatile organic compounds) emissions depend on the composition of the fuel gas. The VOC emissions in table above are based on max 1 mol-% VOC components in the feed fuel gas and are NOT including CH2O.

WHT Natural Gas - Stack Information

	100%	90%	75%	50%	25%	MECL
Flue gas exit temperature (degrees F)	708.4	744.3	746.1	752.9	760.6	
Flue gas flow rate (acfm)	58703	55373	50489	40747	34731	
Flue gas exit velocity (ft/sec)						
Stack Diameter (ft)						

Fuel Oil (USDL) Operation

WHT Fuel Oil - Treated Emissions

Treated Emission Summary & Conversion Tables

Applicable to one engine (steady state) (Not an average over all engines)

		100%	90%	75%	50%	40%	Minimum Emissions Compliance* 40%
NOx (as NO2)	**ppm-v, 15 % O2, dry**	35	35	35	40	40	
CO	**ppm-v, 15 % O2, dry**	20	20	20	20	20	
VOC (as CH4)	**ppm-v, 15 % O2, dry**	40	40	40	40	40	
VOC (as C3H8)	**ppm-v, 15 % O2, dry**	13.33	13.33	13.33	13.33	13.33	
Ammonia	**ppm-v, 15 % O2, dry**	10	10	10	10	10	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**g/kWhe**	0.53	0.53	0.53	0.63	0.66	
CO	**g/kWhe**	0.18	0.18	0.19	0.19	0.2	
VOC (as CH4)	**g/kWhe**	0.21	0.21	0.21	0.22	0.23	
VOC (as C3H8)	**g/kWhe**	0.19	0.19	0.19	0.20	0.21	
PM10 (Total Front/back half)	**g/kWhe**	0.22	0.22	0.22	0.31	0.32	
PM2.5 (Total Front/back half)	**g/kWhe**	0.22	0.22	0.22	0.31	0.32	
Ammonia	**g/kWhe**	0.06	0.06	0.06	0.06	0.06	
CO2	**g/kWhe**	619	616	620	639	672	
		100%	90%	75%	50%	40%	40%
NOx (as NO2)	**lb/hr**	10.86	9.62	8.22	6.43	5.36	
NOx (as NO2)	**lb/mmbtu**	0.1440	0.1439	0.1437	0.1643	0.1642	
CO	**lb/hr**	3.78	3.35	2.86	1.96	1.63	
CO	**lb/mmbtu**	0.0501	0.0501	0.0500	0.0500	0.0500	
VOC (as CH4)	**lb/hr**	4.33	3.83	3.28	2.24	1.87	
VOC (as C3H8)	**lb/mmbtu**	0.0526	0.0525	0.0525	0.0525	0.0525	
PM10 (Total Front/back half)	**lb/hr**	4.53	4.02	3.43	3.13	2.61	
PM10 (Total Front/back half)	**lb/mmbtu**	0.0601	0.0601	0.0600	0.0801	0.0800	
PM2.5 (Total Front/back half)	**lb/hr**	4.53	4.02	3.43	3.13	2.61	
PM2.5 (Total Front/back half)	**lb/mmbtu**	0.0601	0.0601	0.0600	0.0801	0.0800	
Ammonia	**lb/hr**	1.15	1.02	0.87	0.6	0.5	
Ammonia	**lb/mmbtu**	0.0152	0.0152	0.0152	0.0152	0.0152	
CO2	**lb/mmBtu**	171.5	171.5	171.4	171.1	171.0	
	pounds per hour per engine						
Formaldehyde	**lb/hr**	-	-	-	-	-	
Formaldehyde	**lb/mmBtu**	-	-	-	-	-	
Acrolein	**lb/hr**	-	-	-	-	-	
Acrolein	**lb/mmBtu**	-	-	-	-	-	
Acetaldehyde	**lb/hr**	-	-	-	-	-	
Acetaldehyde	**lb/mmbtu**	-	-	-	-	-	
Methanol	**lb/hr**	-	-	-	-	-	
Methanol	**lb/mmbtu**	-	-	-	-	-	
Heat Input	**mmBtu/hr HHV**	79.6	71.3	59.8	41.1	34.7	
Output	kWe-gross	9,370	8,433	7,027	4,685	3,748	

mmBtu = one million British thermal units (1 Btu = 1,05506 kJ), LHV

*Please enter in the minimum emissions compliance load for permitting, along with emissions at that load

WHT Fuel Oil - Start-up/Shutdown Emissions

Component	Emissions per Cold Start[A]	Emissions per Warm Start[B]	Emissions per Hot Start[C]	Emissions per Shutdown
	lb	lb	lb	lb
NO_x	45	36	32	0.2
Formaldeyde	-	-	-	-
CO	6	5.1	5	0.1
VOC as CH_4	2.5	2.15	1.8	0.1
VOC as C3H8	2.29	1.97	1.65	0.09
PM_{10}	5	5	5	0.05
PM2.5 (total)	5	5	5	0.05
CO_2	6398	6398	6398	213
Start-up Assumptions				
RICE Start-up duration (Hours)	30 min	30 min	30 min	
Shutdown Assumptions				
RICE Shutdown duration (Hours)				1 min

[A] A cold start is the engine has not operated in last 2-3 days

[B] Warm start is engine is restarted 6-12 hours after last shutdown

[C] Hot start is engine was shutdown in the last 6 hours

WHT Fuel Oil - Stack Information

	100%	90%	75%	50%	25%	MECL
Flue gas exit temperature (degrees F)	629	608	608	625	608	
Flue gas flow rate (acfm)	68281	62260	56967	54032	44250	
Flue gas exit velocity (ft/sec)						
Stack Diameter (ft)						

Wartsila estimates the emissions rates per engine at 10% load to be NOx as NO2 - 10 g/s, CO - 2 g/s, PM - 1 g/s, THC - 2 g,
Wärtsilä estimates the maximum emission rates at 25% load would be NOx as NO2 15 g/s, CO 2 g/s, PM 1 g/s, and THC 2

103. GUARANTEE DATA

103.1 Table 3-1a below lists the conditions to be used for the performance guarantee(s).

Table 3-1a. Blue Lake Guarantee Conditions

Parameter	FUEL GAS Summer Case 1 (1% Dry Bulb) Guarantee Data	FUEL OIL Summer Case 1 (1% Dry Bulb) Guarantee Data
Site Elevation	760 feet AMSL	760 feet AMSL
Barometric Pressure	14.32 psia	14.32 psia
Dry Bulb Temperature(s)	88.2°F	88.20°F
Relative Humidity	60.2%	60.2%
Wet Bulb Temperature	72.7°F	72.7°F
Fuel	Natural Gas per Appendix ~~48 50 32-A~~ 48 50 43-A	Fuel Oil per Appendix ~~48 50 32-A~~ 48 50 43-C
Fuel gas supply pressure at RICE skid inlet	[By Supplier]	[By Supplier]
Fuel gas supply temperature at RICE skid inlet	[By Supplier]	[By Supplier]
Power Factor (lagging)	0.85	0.85
Frequency	60 Hz	60 Hz
Static Exhaust Pressure	By Supplier in ” w.c.	By Supplier in ” w.c.

Guaranteed operating temperature range at all loads and meeting all emissions guarantees: -41°F to +106°F

Table 3-2b. Wheaton Guarantee Conditions

Parameter	FUEL GAS Summer Case 1 (1% Dry Bulb) Guarantee Data	FUEL OIL Summer Case 1 (1% Dry Bulb) Guarantee Data
Site Elevation	926 feet AMSL	926 feet AMSL
Barometric Pressure	14.24 psia	14.24 psia
Dry Bulb Temperature(s)	86.7°F	86.7°F
Relative Humidity	59.6%	59.6%
Wet Bulb Temperature	71.0°F	71.0°F
Fuel	Natural Gas per Appendix ~~48 50 32-A~~ 48 50 43-B	Fuel Oil per Appendix ~~48 50 32-A~~ 48 50 43-C
Fuel gas supply pressure at RICE skid inlet	[By Supplier]	[By Supplier]
Fuel gas supply temperature at RICE skid inlet	[By Supplier]	[By Supplier]
Power Factor (lagging)	0.85	0.85
Frequency	60 Hz	60 Hz
Static Exhaust Pressure	By Supplier in ” w.c.	By Supplier in ” w.c.

Guaranteed operating temperature range at all loads and meeting all emissions guarantees: -41ºF to +106ºF

Attachment 6 - Wartsila Summary on Diesel Particulate Filter Technology

Title:	Summary on Diesel Particulate Filter Technology	**Doc.ID:**	DBAD995323
		Revision:	-
Author:	Hanna Strandberg	**Status:**	Checked
Checked by:	Hanna Strandberg / 17.08.2016	**Pages:**	1 (2)
Organisation:	- General Energy Solutions		
Project:	IN026 – WNS-P DOCVISION		

Released to Xcel to Public distribution for permitting purposes.
2024-05-24 | Greg Bosley, Wartsila Energy, Engine Power Plants

Summary on Diesel Particulate Filter Technology

1 Diesel Particulate Filter Technology

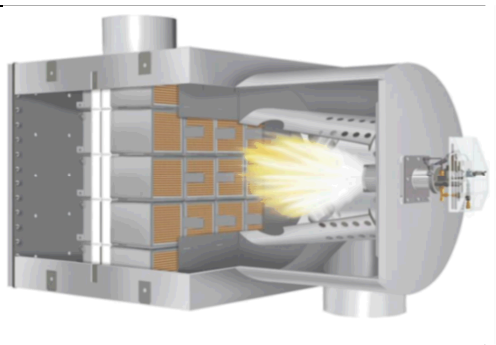
Diesel Particulate Filters (DPF) are established technology for automotive engine applications but experience on large bore medium speed diesel engines is limited. The reason for this is that the fuel used in larger bore engines often has a higher concentration of impurities, in particular the sulfur content has been higher, the difference in lube oil quality (the automotive industry often uses synthetic oils) and the different load profiles. The load variations in automotive applications partly regenerate the filter while power plant engines have traditionally been optimized for steady high load.

The best diesel particulate abatement is achieved with a so called “wall flow filter” where the flue gases passes through a porous filtering material. This filter type is extremely efficient but has a high pressure drop. DPF can also be coated, enabling chemical reaction for lowering the regeneration temperature. Non coated DPFs need periodically active regeneration, either with fuel injection or burners. There are reports from the non-road mobile engine/car industry that the DPF PM removal efficiency is typically over 85 %.

2 Wärtsilä experience

Wärtsilä has no installed DPF references, but in year 2010 a Wärtsilä diesel engine equipped with a diesel oxidation catalyst and particle oxidation catalyst (DOC + POC) for PM removal in combination with a SCR system was tested in the field. The engine was operating on LBF (palm oil). The initial measured PM removal efficiency of the DOC&POC system was approx. 70 % (when measuring both filterable and condensable particulates) and the back pressure over 100 mbar, far in excess of the normal limits on back pressure for this type of engine. The engine was derating due to the extreme back pressure. When considering only the dry

filterable particulates measured with ISO 9096, EPA method 17 or 5 (method typically used in thermal power industry) no reduction could be seen. The chemical analyses showed that the particle reduction over DOC+POC was mostly derived from the oxidation of the organic carbon fraction of the condensable part of the PM emission. Since the initial field measurements did not meet the expectations, the test was stopped at an early stage and no long time experience was obtained.

	
Diesel Oxidation Catalyst (DOC) regeneration with catalyst material (POC)	Diesel particulate filter Regeneration with catalyst material and burner

The DPF system is expensive (approximately double the price of a Selective Catalytic Reduction system) and needs frequent regeneration (fuel) or mechanical cleaning which has a negative impact on OPEX cost and plant availability. The high backpressure of the system will cause power reduction and efficiency drop on the engine. An induced draft exhaust fan to try to mitigate this will add to the plant's parasitic load consumption figures and to plant complexity. The regeneration sequences need proper control, otherwise an uncontrolled situation with extreme exhaust gas temperatures may destroy the DPF. The sum of all these factors excludes the combined DPF+SCR system from the recommended Best Available Control Technique (BACT) list.

3 Conclusion

As a leading engine builder and as an environmentally conscious manufacturer, Wartsila has kept a close watch on the development of DPF technology over the years and has had contact with suppliers of automotive DPF technology to discuss their technology and the aspects of it which might apply to large bore, medium speed engines using a variety of fuels. To date no supplier has come forth with a technology which meets our customers demand.

Attachment 7 - Points Calculator

Points Calculator

1) AI ID No.: 1860
2) Facility Name: Xcel Energy - Blue Lake
3) Small business? y/n? no
4) Air Project Tracking **Numbers (including all** 7272
5) Date of each Application Received: 11/3/2023
6) Final Permit No. 13900010-105
7) Permit Staff Tarik Hanafy

Total Points 185

Application Type	Air Project Tracking No.	Tempo Activity ID	Qty.	*Points*	Total Points	Total Cost	Details
Administrative Amendment				*1*	0	$ -	
Minor Amendment				*4*	0	$ -	
Applicability Request				*10*	0	$ -	
Moderate Amendment				*15*	0	$ -	
Major Amendment	7272	IND20220001	1	*25*	25	$ 7,125.00	
Individual State Permit (not reissuance)				*50*	0	$ -	
Individual Part 70 Permit (not reissuance)				*75*	0	$ -	
Additional Points							
Modeling Review	7272	IND20220001	1	*15*	15	$ 4,275.00	NAAQS, Increment Class II model
BACT Review	7272	IND20220001	7	*15*	105	$ 29,925.00	PM, PM10, PM2.5, Nox, CO, VOC,
LAER Review				*15*	0	$ -	
CAA section 110(a)(2)(D)(i)(I) Review (i.e., Transport Rule/CAIR/CSAPR)				*10*	0	$ -	
Part 75 CEM analysis				*10*	0	$ -	
NSPS Review	7272	IND20220001	2	*10*	20	$ 5,700.00	subp. IIII, JJJJ
NESHAP Review	7272	IND20220001	1	*10*	10	$ 2,850.00	subp. ZZZZ
Case-by-case MACT Review				*20*	0	$ -	
Netting				*10*	0	$ -	
Limits to remain below threshold	7272	IND20220001	1	*10*	10	$ 2,850.00	limit to avoid EAW
Plantwide Applicability Limit (PAL)				*20*	0	$ -	
AERA review				*15*	0	$ -	
Variance request under 7000.7000				*35*	0	$ -	
Confidentiality request under 7000.1300				*2*	0	$ -	
EAW review					0		
Part 4410.4300, subparts 18, item A; and 29				*15*	0	$ -	
Part 4410.4300, subparts 8, items A & B; 10, items A to C; 16, items A & D; 17, items A to C & E to G; and 18, items B & C				*35*	0	$ -	
Part 4410.4300, subparts 4; 5 items A & B; 13; 15; 16, items B & C; and 17 item D				*70*	0	$ -	
			Add'l Points		**160**		

NOTES: