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Submitted Via KY One Stop Portal

December 7, 2023

Mr. Zachary Bittner
Permit Review Branch Manager
Permit Review Branch
Kentucky Division for Air Quality
300 Sower Boulevard, 2nd Floor
Frankfort, Kentucky 40601

RE: Title V Air Permit Renewal Application
Kentucky Utilities Company-EW Brown Generating Station (AI # 3148)

Dear Mr. Bittner:

Kentucky Utilities Company owns and operates the EW Brown Generating Station in Mercer County, Kentucky. This electric generating facility is classified as a major source under the Title V operating permit program and it currently operates under permit V-17-030 R1. As required by 401 KAR 52:020, Section 12 and noted in Section G (2) (a) of the current permit; KU is submitting an electronic copy of the EW Brown Generating Station Title V renewal permit application via the KY One Stop Portal. The current permit was issued June 8, 2019 and it expires June 8, 2024.

The renewal application has been signed by Steve Turner, the responsible official (designated representative) for KU's EW Brown Generating Station. If you have any questions, please feel free to call (502)-627-4156.

Sincerely,

Kristin Baker
Environmental Engineer

Business Use

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TITLE V AIR PERMIT RENEWAL APPLICATION

Kentucky Utilities Company
E.W. Brown Generating Station
815 Dix Dam Rd
Harrodsburg, KY 40330

Agency Interest # **3148**



December 7, 2023

Prepared By:

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1. APPLICATION SUMMARY

1.1 Purpose of Application

Kentucky Utilities Company (KU) currently operates the E.W. Brown Generating Station (Brown Station) located outside of Harrodsburg, Kentucky in Mercer County. The facility is classified as a major source under the Title V Operating Permit Program, Prevention of Significant Deterioration (PSD) construction permitting program, and National Emissions Standards for Hazardous Air Pollutants (NESHAP) federal regulatory program. The Brown Station currently operates in accordance with Title V Permit No. V-17-030 R1, issued by the Kentucky Division for Air Quality (Division) on June 8, 2019, and most recently revised on July 16, 2021. As the permit expires on June 8, 2024, a renewal application for the permit must be submitted at least six months prior to the permit expiration date, or by December 8, 2023.

This document and its appendices constitute the renewal application for the Brown Station, as required by Condition G.2.a. of the existing permit and 401 KAR 52:020, Section 12. In accordance with 401 KAR 52:020, Section 4(2)(c), this renewal application provides "only the information that is new or different from the most recent source-wide permit application." The most recently submitted source-wide permit application was the Significant Permit Revision application for the construction of emissions units associated with a new natural gas combined cycle (NGCC) turbine project, which was submitted in December 2022. Thus, this application focuses on new information since submittal of the NGCC turbine project application that is necessary to accurately characterize the facility's current operations.

1.2 Summary of Application Contents

Following this introduction, a brief description of the existing process operations located at the Brown Station is provided in Section 2. Section 2 also identifies each permit action undertaken by the Brown Station since the issuance of V-17-030 R1. Section 3 presents emission estimates for insignificant activities (IAs) not identified by either Section B or Section C of the current permit. Section 4 provides an overview of applicable regulatory requirements under state and federal air quality programs, including those that are new or different from the most recent source-wide permit application. Section 5 identifies KU's requested changes to the current Title V permit, which are being sought as part of this renewal permit action.

Updated facility maps and process flow diagrams are provided in Appendix A, as necessary for this renewal. Kentucky's DEP7007 series application forms are provided in Appendix B for updates requested through this permit renewal application. Appendix C presents an emission unit (EU) index summarizing the significant EUs and IAs operational at the Brown Station, as well as new emission calculations for IAs at the Brown Station. Lastly, Appendix D documents KU's suggested permit revisions to be incorporated into the Title V permit upon renewal.

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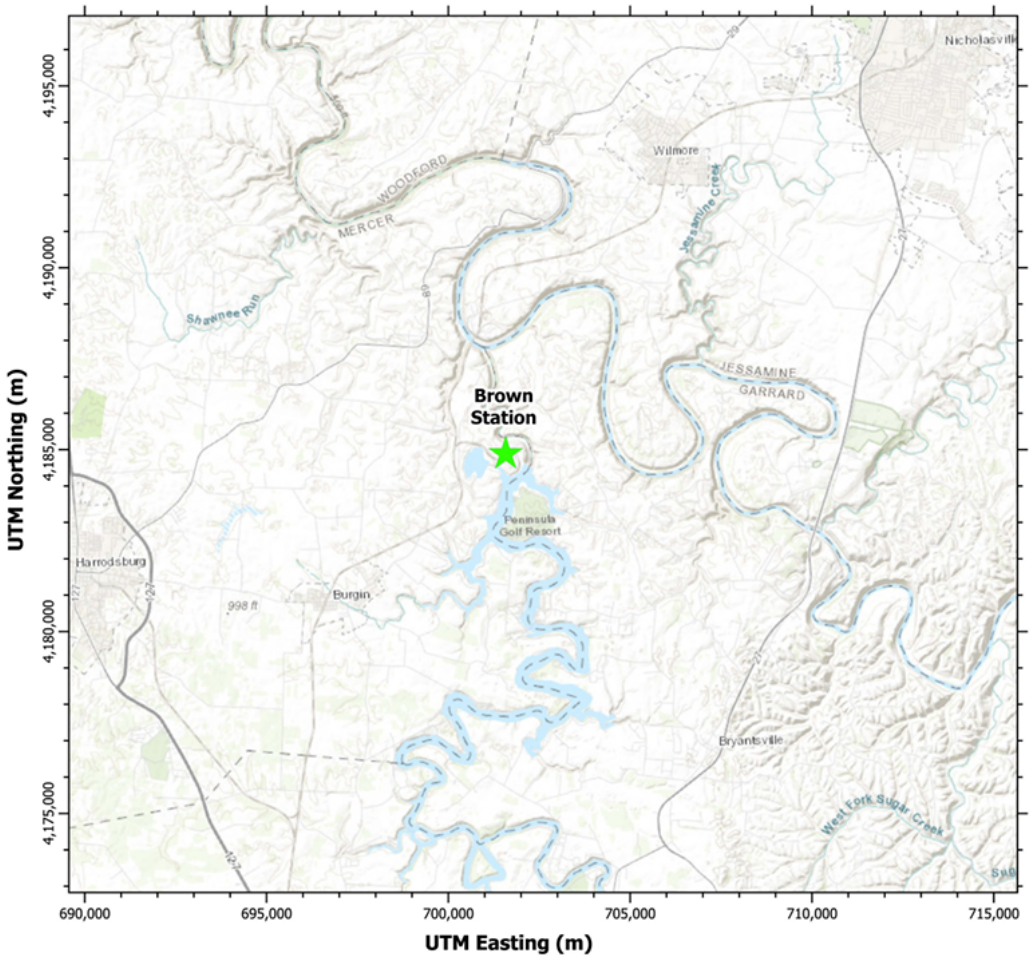
2. FACILITY DESCRIPTION

2.1 Site Location

The Brown Station is located approximately 25 miles southwest of Lexington and 7.5 miles east-northeast of Harrodsburg, Kentucky (Mercer County) along the west shore of Lake Herrington in the Dix River Valley. The property encompasses an area of approximately 1,222 acres.

Figure 1 shows the facility location and the surrounding area on a topographical map. The Universal Transverse Mercator (UTM) coordinates of the Brown Generating Station's center are (approximately) 701.319 kilometers (km) East and 4,184.791 km North (Zone 16, NAD83).

Figure 1. Area Map of Brown Generating Station



2.2 Background on Existing Site Operations and Emission Units

Brown Station is an electrical generating power plant that began operation in the 1950s. The primary emission unit at the plant is one coal-fired utility boiler (Unit 3). Seven combustion turbines are also present that are used to provide peaking power. Previously, there were three large coal-fired utility boilers at the

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plant. However, KU submitted a minor permit revision to the Division on March 13, 2019, to retire Units 1 and 2. They were officially retired on March 1, 2019.

Unit 3 began service in 1971 and is still in operation. Unit 3 is a pulverized coal, dry bottom, tangentially-fired boiler. It has a heat input capacity of 5,300 MMBtu/hr and a nameplate power output rating of 464 MW. Air pollution controls on Unit 3 consist of low NO_X burners (LNBs), Selective Catalytic Reduction (SCR), a powdered activated carbon (PAC) injection system, a dry sorbent injection (DSI) system (and/or liquid additive system), a pulse-jet fabric filter (PJFF) baghouse, and a wet flue gas desulfurization (WFGD) unit. An updated process flow diagram is provided in Figure A-2 in Appendix A.

In addition to the potential 464 MW generated from Unit 3; the Brown Generating Station also has a 33 MW hydroelectric plant, a 10 MW solar facility, and 981 MW of capacity from seven simple-cycle natural gas-fired combustion turbines (CT).

2.3 Title V Permit History Summary

The current Title V permit for the Brown Station was most recently revised on July 16, 2021. Table 2-1 below summarizes all permit actions that have been submitted since issuance of the most recent revised permit.

Requisite DEP7007 series application forms were included with each of the submittals since the previous permit renewal, so the forms included in Appendix B to this renewal application are limited to only those forms required to reflect existing equipment not currently represented in the permit.

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Table 2-1. Summary of Permit Actions

Date	Type of Permit Action	Title	Permit Action Summary
03/2021	Minor Permit Revision	Establishment of Additional Operating Scenarios for Units 23-28	KU submitted a minor permit revision application to establish two scenarios for operation of Emission Units 23-28 on distillate fuel oil. One scenario is as a secondary fuel in which all of the requirements in V-17-030 applicable to distillate fuel oil remain unchanged. The second scenario is as an emergency fuel, to be used only during times that natural gas is unavailable, in order to preclude performance testing on distillate fuel during the limited use.
03/2022	Off-Permit Change	Revisions to IA List	KU submitted an off-permit change notification to add one new diesel fuel tank (IA40, T-39) to Section C and to revise the description of one existing IA (IA39) in Section C to include three additional diesel fuel tanks (T-36, T-37, and T-38).
04/2022	Section 502(b)(10) Change	Revision for Units 47 & 48	EU47 and EU48 are designated as Emergency Quench Water Pump Engines in the current Title V permit. Through this Section 502(b)(10) change notification, KU requested that these two engines be moved from the emission unit group for New Emergency CI RICE to the emission unit group for New CI Emergency Fire Pump RICE alongside existing Emergency Fire Pump Engines, EUs 45-46.
12/2022	Significant Permit Revision	Addition of NGCC	Planned installation and operation of a new 664 MW (net) natural gas-fired combined cycle (NGCC) electric generating unit (Unit 12) in conjunction with shutting down the existing Unit 3 coal boiler and all its associated material handling and other support operations. On November 6, 2023, the Kentucky Public Service Commission issued a final Order to KU to deny the shutdown of Unit 3 and installation of Unit 12. The Commission then stated that the denial of the Certificates of Public Convenience and Necessity (CPCN) for Unit 12 was wholly based on the Commission's finding that the construction of Unit 12 should be deferred with the construction beginning on a date that provides for an in-service date in 2030.

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3. EMISSION CALCULATION UPDATES

As established by 401 KAR 52:020, Section 4(2)(c), Kentucky's regulations allow applicants to limit the scope of a renewal application to information that is new or different from the most recent facility-wide permit application. Accordingly, the scope of the emission calculations included in this permit renewal application has been tailored to only address necessary updates to the existing emissions information and the air emissions impacts from new emissions generating processes. The following subsections of this renewal application detail the air emissions impacts from new insignificant activities not currently identified by permit V-17-030 R1.

3.1 Additional Emission Point at Coal Crusher

EU16 includes four coal crushers and the crusher house. In this process, coal is fed from the coal yard via conveyor belts into the crusher house prior to being conveyed to the coal bunkers for the feed to the Unit 3 boiler. Emissions from the crushing process are controlled by a wet scrubber and are quantified on the KyEIS under EQPT1, Process ID 1.

The Brown Station also employs a vacuum system for cleaning the floors and miscellaneous locations in and around the crusher house. All coal collected from the crusher house is recycled back onto the crusher house feed conveyor. This recycle loop allows for crushed coal that falls off the crusher house conveyor belts to be vacuumed and routed back through the crusher house prior to use in the Unit 3 boiler. A blower draws 1,413 cubic feet per minute (cfm), resulting in a vacuum pickup point that entrains the coal particles in an air stream that goes through a material recovery cyclone to separate the coal particles from the transfer air. The transfer air, with some entrained particulate, is vented to the atmosphere from an aspiration point on the cyclone.

The particulate matter (PM) potential-to-emit (PTE) from the pneumatic transfer aspiration point has been calculated based on the blower rating associated with the vacuum system and a conservative outlet grain loading from the cyclone. All PM is conservatively presumed to be PM 10 microns or less in diameter (PM_{10}) and PM 2.5 microns or less in diameter ($PM_{2.5}$) at the cyclone exhaust. Furthermore, since the cyclone is an integral process recovery device for recycling crushed coal back to the crusher house, the uncontrolled emissions are based on emissions exiting the cyclone. The PTE for this new emission point is detailed in Appendix C. Since the PM/PM_{10}/$PM_{2.5}$ PTE is less than five tpy, the recycle cyclone is considered an insignificant activity and is included on the DEP7007DD form in Appendix B.

3.2 Additional Material Storage Activities

Upon review of the Brown Station's operations in preparation for developing this renewal application, KU noted four (4) additional storage vessels not currently captured by the Title V permit. The following storage vessels are requested to be added to the Title V permit:

- One (1) 3,000-gal propylene glycol tank
- Two (2) lube oil storage tanks (T-31 and T-32)
- One (1) 180-gal hydrazine monohydrate tote

As with other storage vessels at the Brown Station, KU has estimated potential emissions from the propylene glycol tank, T-31, and T-32 using TankESP®, an application which follows the emissions calculation methodologies presented in EPA's AP-42 publication, Chapter 7.1. Using this calculation

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methodology, the volatile organic compound (VOC) PTE from each of these three tanks is estimated to be less than 0.01 tpy.

A stainless-steel shuttle tote holding hydrazine is within the building housing Unit 3. The hydrazine monohydrate is added to the feed water injected into Unit 3 to act as an oxygen scavenger and remove oxygen from the feed water to prevent equipment corrosion. Hydrazine is a hazardous air pollutant (HAP). The hydrazine monohydrate is injected in trace concentrations (typically 1 part per billion), and most of the hydrazine reacts with the dissolved oxygen. As such, emissions of hydrazine from the storage and injection of the hydrazine monohydrate are negligible, and the Unit 3 PTE calculations have not been updated to incorporate this process. KU requests the storage of the hydrazine monohydrate be added to Section C of the Title V permit upon renewal to more accurately reflect the materials stored to support the operation of Unit 3.

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4. SUMMARY OF APPLICABLE REQUIREMENTS

Section 4.1 provides general air quality regulatory information for the Brown Station, including the facility's status with respect to the PSD and Title V permitting programs. Any relevant updates to state and federal air regulatory requirements are addressed in Section 4.2 on an applicable regulation basis.

4.1 Source Classification

4.1.1 PSD Permitting Program

Kentucky has incorporated the requirements of the PSD permitting program into its State Implementation Plan (SIP) at 401 KAR 51:017.[1]

The PSD requirements apply to the construction of a new *major stationary source* (as defined in 401 KAR 51:001, Section 1(118)) **or** any project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407 (d)(1)(A)(ii) and (iii) that is a major modification.

A stationary source is a major source if the potential to emit for a specific pollutant equals or exceeds the major source threshold for *regulated New Source Review (NSR) pollutants*.[2] The regulated NSR pollutants of relevance to the Brown Generating Station and the NGCC Project are nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), PM, PM_{10}, $PM_{2.5}$, VOC, lead, and sulfuric acid (H_2SO_4) mists.

The threshold for defining a facility as a major stationary source under the PSD permitting program is 250 tpy of any regulated NSR pollutant unless the facility belongs to one of 28 specially named source categories (List of 28), in which case the major stationary source threshold is 100 tpy.[3,4] Existing operations at the Brown Station, classified under SIC Code 4911, "Electric Services", include "fossil fuel-fired steam electric plants," which is a named category on the List of 28. As such, the major source threshold for the PSD program is 100 tpy. The potential emissions of at least one regulated NSR pollutant currently exceeds 100 tpy; therefore, the Brown Station is classified as an existing major stationary source under the PSD program.

As a renewal application for an operating permit, this submittal is not associated with a construction project or a facility modification that involves PSD applicability considerations. Accordingly, new PSD requirements are not triggered by this permit action.

4.1.2 Title V Permitting Program

40 CFR Part 70 contains the regulations implementing the federal Title V permit program. Kentucky has incorporated the provisions of this federal program in its Title V program at 401 KAR 52:020. As specified in

[1] 40 CFR 51.166(a)(1)

[2] *Regulated NSR Pollutant* defined in 401 KAR 51:001, Section 1(207)

[3] 401 KAR 51:001, Section 1(118)

[4] Being a List of 28 source says nothing about whether a facility is classified as a minor or major source under PSD or whether it is subject to PSD permitting requirements. Being on the List of 28 imparts no particular regulatory requirements or permitting obligations. It only defines what the major source threshold is for a facility in an attainment area.

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401 KAR 52:001, Section 1(46), a major source with respect to the Title V regulations encompasses facilities with potential emissions of 100 tpy of any regulated pollutant, 10 tpy of any single HAP, and/or 25 tpy of any combination of HAPs. The Brown Station is a major source for $PM/PM_{10}/PM_{2.5}$, SO_2, NO_X, CO, VOC, hydrochloric acid, hydrofluoric acid, formaldehyde, and combined HAP that is currently operating under a Title V permit and will continue to operate as a major source under the Title V program upon renewal.

4.2 Regulatory Applicability Review

A summary of applicable federal and state requirements is included in the following subsections. While no newly applicable federal or state regulations were triggered as a result of the permit actions undertaken by the Brown Station since issuance of the most recent revision to the current Title V permit, currently applicable requirements will extend to the newly added emission units described in Section 3 of this application.

4.2.1 New Source Performance Standards (NSPS)

NSPS require new, modified, or reconstructed sources in applicable source categories to control emissions to the levels achievable by the best demonstrated technology as specified in the applicable provisions. The following NSPS subparts are currently applicable to the Brown Station and will remain applicable upon permit renewal:

- Subpart A – General Provisions
- Subpart Y – Standards of Performance for Coal Preparation and Processing Plants
- Subpart GG – Standards of Performance for Stationary Gas Turbines
- Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants
- Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

There are no newly applicable NSPS as a result of the new IAs described in Section 3 that are requested to be added to the permit upon permit renewal. Within Appendix D, KU is requesting minor revisions to permit conditions referencing NSPS Subpart IIII to accurately reflect the current regulatory language.

4.2.2 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

NESHAP, located in 40 CFR 61 and 40 CFR 63, have been promulgated for designated pollutants and source categories that emit HAP to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAP and/or 10 tpy of any individual HAP. Facilities with a potential to emit HAP at an amount less than that which is defined as a major source are otherwise considered an area source. For major HAP sources, allowable emissions limits are established (under 40 CFR 63) on the basis of a maximum achievable control technology (MACT) determination for the particular major source type or category. The NESHAP under 40 CFR 63 applies to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

Brown Station is a major source of HAP. No units are being shut down as part of this renewal process, nor is KU seeking to demonstrate a decrease in HAP emissions via updated calculation methodologies. As such, Brown Station will remain a major source of HAP. The following NESHAP subparts are currently applicable to the Brown Station and will remain applicable upon permit renewal:

- Subpart YYYY – NESHAP for Stationary Combustion Turbines

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- Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines
- Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters
- Subpart UUUUU – NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units

There are no newly applicable NESHAP as a result of the new units described in Section 3 that are requested to be added to the permit upon permit renewal. Within Appendix D, KU is requesting revisions to permit conditions referencing NESHAP Subparts ZZZZ and UUUUU to accurately reflect the current regulatory language.

4.2.3 Compliance Assurance Monitoring (CAM)

Under 40 CFR Part 64, the CAM regulations, facilities are required to prepare and submit monitoring plans for certain emission units. The CAM plans are intended to document methods that will provide ongoing and reasonable assurance of compliance with emission limitations. Pursuant to 40 CFR 64.2(a), the CAM regulations apply to a pollutant-specific emissions unit (PSEU), as defined in 40 CFR 64.1, at a major Title V source if each of the following criteria are met:

- The PSEU is subject to an emissions limitation or standard for the regulated pollutant, other than an emission limitation or standard that is exempt under 40 CFR 64.2(b);
- The PSEU uses a control device as defined in 40 CFR 64.1 to achieve compliance with the emissions limitation; and
- The PSEU has potential uncontrolled emissions of the applicable regulated air pollutant that are equal to or greater than Title V major source thresholds.

The Unit 3 Boiler is currently subject to CAM requirements as it meets all of the criteria above and does not meet any of the exemptions in 40 CFR 64.2(b). KU is not requesting a revision to the applicability of CAM to Unit 3, and none of the new units described in Section 3 will meet the three criteria above to trigger CAM requirements.

4.2.4 Interstate Trading Programs

Starting with the Acid Rain Program mandated by the 1990 Clean Air Act Amendments, EPA has developed several market-based "cap and trade" regulatory programs. All market-based regulatory programs are overseen by EPA's Clean Air Markets Division (CAMD) and are referred to as CAMD regulations. The programs that are potentially applicable to KU are:

- Acid Rain Program (ARP) (1990 – ongoing)
- Cross-State Air Pollution Rule (CSAPR) (2015 – ongoing)

Changes are needed to Section L of the permit regarding CSAPR as a result of Federal Register revisions that have occurred in June and July of 2023. See 88 FR 36890, June 5, 2023; and 88 FR 49303, July 31, 2023. With the stay of the SIP disapprovals, KY is not able to participate in the Group 3 trading program. With the Interim Final Rule, published on August 4, 2023, KY EGU's fall back to the CSAPR NO_X Ozone Season Group 2 Trading Program in 40 CFR 97 Subpart EEEEE and operate under a new "Expanded G2" NO_X ozone season trading program per 52.38(b)(14). All 40 CFR 97 Subpart GGGGG references should be changed to appropriate Subpart EEEEE/Expanded G2 references. See additional comments and recommendations in the permit redline/strike-out changes shown in Appendix D.

In addition, please note the change to the Table in Section L regarding the simple cycle turbines, where KU has always used 40 CFR 75, Appendix D.

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4.2.5 Kentucky State Implementation Plan (SIP) Regulations

Various emission units at the Brown Station are also subject or potentially subject to Kentucky Administrative Regulations (401 KAR) as well as operating limitations and emission limitations that were developed in pre-Title V construction permits (e.g., PSD avoidance limits).

KU is not requesting any changes to the existing applicability of any Kentucky SIP requirements as part of this permit renewal application. However, KU is requesting that equipment not currently represented in the permit be added as part of the renewal, as detailed in Section 3. The following regulatory analysis of Kentucky SIP regulations is limited to only those rules that would be potentially applicable to the emission units not currently represented by the permit.

4.2.5.1 401 KAR 59:010 – New Process Operations

Pursuant to 401 KAR 59:010, Section 1(1), particulate emissions from new process operations not subject to other emission standards with respect to particulates in Chapter 59 and that are constructed after July 2, 1975, are subject to this generally applicable rule. The affected operations covered include any "method, form, action, operation, or treatment of manufacturing or processing, and shall include any storage or handling of materials or products, before, during, or after manufacturing or processing." Section 3 of the rule establishes opacity and PM mass emissions standards. Opacity of continuous emissions (visible emissions of particulate matter persisting for more than three minutes) is limited to 20 percent from any control device or stack associated with an affected operation, while PM emissions are limited by the "process weight rule."

The crusher house cleanup operation described in Section 3.1 is subject to 401 KAR 59:010. This process is an operation not subject to other emission standards with respect to particulates in Chapter 59. As such, this new emission point is subject to the opacity standards and process weight rule defined in 401 KAR 59:010. This rule is captured as an applicable regulation on the DEP70007DD form included in Appendix B. Based on its status as an IA, KU demonstrates compliance with the opacity requirements by conducting monthly visible emissions observations at the cyclone aspiration point. As shown by the PTE calculations for this process included in Appendix C, the PTE on an hourly basis is 0.17 tph; as such, the crusher house cleanup operation will be inherently compliant with the lowest allowable PM emission rate under 401 KAR 59:010.

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5. UPDATES TO TITLE V PERMIT FOR RENEWAL

As part of the permit renewal application process, certain changes to the current Title V permit are being requested – beyond those outlined in the permit actions identified in Table 2-1 – to update, where necessary, regulatory citations, emission unit nomenclature/listings, and other representations. An explanation of changes related to regulatory changes is provided in Section 4, and any other requested change warranting explanation is supplemented with a comment balloon in the suggested Title V permit provided in Appendix D of this application package.

5.1 Requested Updates from Permit Actions

5.1.1 Insignificant Activity Revisions (March 2022 Off-Permit Change)

The Off-Permit Change notification submitted in March 2022 details the revision of the description for IA39 and the addition of IA40. The current permit lists only three total diesel fuel tanks under IA39 – 500-gal, 2,000-gal, and 550-gal. Three additional diesel fuel tanks were requested to be added to IA39 – two 550-gal tanks and one 1,100-gal tank. Additionally, KU requested the inclusion of a mobile diesel fuel tank (251-gal capacity) to the IA list as IA40. These updates are captured on the DEP7007DD form certified in Appendix B.

5.1.2 Emergency RICE Reorganization (April 2022 Section 502(b)(10) Change)

The Section 502(b)(10) change notification submitted in April 2022 details the requested reorganization of EU47 and EU48 within the Title V permit. Currently, EU47 and EU48 are included in an emission unit group alongside EU49 and EU51-52, categorized as "New Emergency CI RICE." Considering EU47 and EU48 are emergency quench water pump engines, KU has requested that these units be moved to the more appropriate emission unit group addressing New CI Emergency Fire Pump RICE (EU45 and EU46). This reorganization will not require any updated regulatory applicability to the New CI Emergency Fire Pump RICE emission unit group as EU45 and EU46 are already subject to 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ. The only update to the permit conditions under the New Emergency CI RICE emission unit group is the removal of Operation Limitation 1.a., which addresses EU47 and EU48 specifically. No changes to the applicability of 40 CFR 60 Subpart IIII or 40 CFR 63 Subpart ZZZZ are necessary for the New Emergency CI RICE emission unit group, which will now consist only of EU49 and EU51-52.

5.2 Insignificant Activity Additions

As detailed by Sections 3.1 and 3.2 of this application, KU is requesting the addition of various IAs to Section C of the permit. As described in Section 3, the individual PTE from the Unit 3 Propylene Glycol Tank (IA44), Lube Oil Tanks T-31 and T-32 (IA45), Hydrazine Storage Tote (IA47), and Crusher House Cleanup Operations (IA48) are all below the thresholds for consideration as an IA per 401 KAR 52:020 Section 6. Additionally, the only applicable regulation to any of these IAs is the generally applicable 401 KAR 59:010, which is applicable to IA48. As such, each of these emissions-generating processes meet the criteria for inclusion in Section C of the permit.

KU is also requesting the addition of a parts washer located in a maintenance shop by the CT plant to the Title V permit as an IA. The degreaser currently used is a powder and does not contain volatiles. As such, it is not a source of fugitive VOC emissions due to solvent evaporation. Nonetheless, in the interest of being comprehensive, KU requests its addition to Section C as an IA (IA46) with no applicable requirements.

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5.3 Miscellaneous Permit Updates

KU is requesting additional revisions to the Title V permit upon renewal separate from the updates requested via permit actions and the defined IA additions described above. The changes described in this section are all also presented as suggested permit revisions in Appendix D to this application.

5.3.1 Clarification of Dispatch Operating Scenario

In February 2023, KU submitted a letter to the Division requesting additional clarification be added to one of the emission limitations for Unit 3. Specifically, KU indicated that the term "dispatch" – as used in Emission Limitation 2.g. and the corresponding Compliance Demonstration Method – was ill-defined and, as such, KU suggested revised permit language to better describe what constitutes a dispatch event. As described by this letter, a dispatch event, which triggers the applicability of a higher NO_X emission limitation of 0.080 lb/MMBtu, is an event where the SCR cannot be safely operated. This scenario would occur during startups, shutdowns, or load ramping. The proposed revisions to Condition 2.g. are included in the suggested permit revisions in Appendix D to this application.

5.3.2 Revision to Combustion Turbine NO_X Emission Limitation Compliance Demonstration Method

Each of the CTs at the Brown Station are permitted within one emission unit group (EU23-29). The NO_X emission limitations for each CT are documented in a table under Condition 2.a. on a parts per million by volume (ppmv) basis. To demonstrate compliance with the ppmv limitations, KU must use the emission rate estimation procedures in 40 CFR 75, Appendix E, and convert to a ppmv basis using Formula F-5 in 40 CFR 75, Appendix F. The performance testing procedures from 40 CFR 75, Appendix E – which include procedures for both initial and repeat performance testing – are included in the permit under the testing requirements for the CTs. From the initial and repeat performance testing, KU establishes acceptable values/ranges for the continuously monitored parameters based on the monitored water-to-fuel ratio in the CTs. In doing so, KU complies with the provisions of 40 CFR Part 75, Appendix E and 40 CFR 60.334(g).

In the context of continuous compliance, however, the continuously monitored water-to-fuel ratio is compared to the acceptable value/range established via performance testing. Per 40 CFR 60.334(j)(1)(i)(A), should the average water-to-fuel ratio for any unit operating hour fall below the established acceptable value/range, then an excess emissions event has occurred. When demonstrating continuous compliance with the NO_X emissions limitations via continuous parametric monitoring, it is implied that KU is demonstrating that no reportable excess emissions are occurring under the 40 CFR 60.331(t)(3) component of the excess emissions definition. Based on this compliance monitoring approach, to conclude that no excess emissions are occurring, the recorded value of a particular monitored parameter (e.g., water-to-fuel ratio) must not be outside the acceptable value/range over the averaging period specified by the performance test which set the acceptable value/range.

Based on the fact that KU is required by 40 CFR 60.334(a) to continuously monitor the fuel consumption rate, hourly average heat input rate, and the water-to-fuel ratio, and that excess NO_X emissions are identified as a result of the parametric measurements falling outside of the acceptable value/range, KU is requesting an update to the Compliance Demonstration Method for Condition 2.a. to clarify the main mechanism by which the Brown Station demonstrates continuous compliance with the NO_X emissions limitations determined via 40 CFR 60.332(a). While the acceptable value/range for monitored parameters and compliance with the NO_X emissions limitations during performance testing are determined using the procedures in 40 CFR 75, Appendix E, compliance with the NO_X emissions limitations outside of performance

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testing is determined via the continuous parametric monitoring required by Condition 4.a. and recordkeeping requirements in Condition 5.a.

KU has included updated language within the suggested permit revisions in Appendix D as an example of the clarifying language requested to differentiate between continuous compliance and compliance demonstrated during initial and repeat performance testing.

5.3.3 General Permit Updates

Various minor updates to regulatory citations and direct language from applicable regulations are requested to coincide with regulatory amendments published since the last permit renewal. For example, certain applicable requirements from NSPS Subpart IIII require updates to remove references to 40 CFR Parts 89 and 94. These minor changes are included in the suggested permit revisions within Appendix D.

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APPENDIX A. MAPS AND PROCESS FLOW DIAGRAMS

- Figure A-1 Aerial Map of Brown Station Generating Showing Arrangement of Existing Operations
- Figure A-2 Air Permitting Process Flow Diagram for Brown Generating Station

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a PPL company

Figure A-1 Aerial Map of Brown Station Showing Arrangement of Existing Operations

Generation Services

Document Management

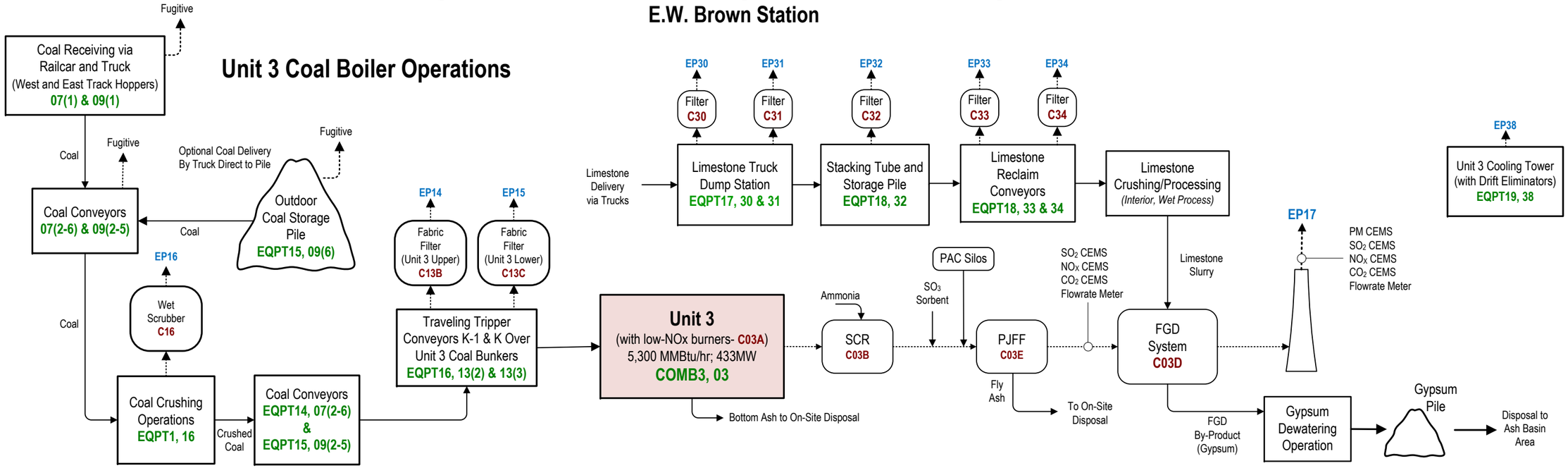
E.W. BROWN
"YOU ARE HERE"
BASIC SITE LAYOUT

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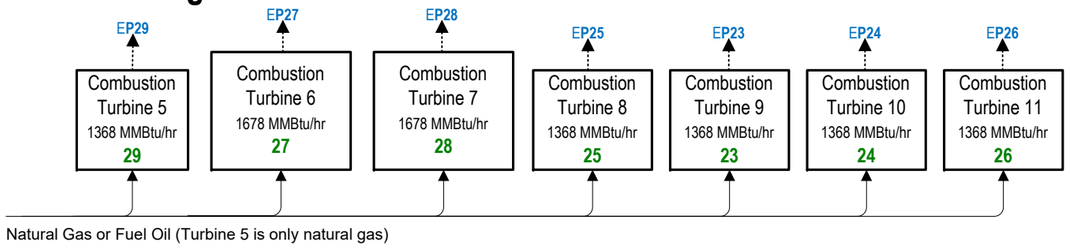
Figure A-2 Air Permitting Process Flow Diagram

E.W. Brown Station

Unit 3 Coal Boiler Operations



Peaking Turbines



KyEIS IDs are shown in **green**. (Process IDs in parentheses)
KU defined control device IDs are shown in **maroon**.
KU defined emission points are shown in **blue**.

Air Permitting
Process Flow Diagram for
E.W. Brown Station

KU
a PPL company
Harrodsburg, Kentucky

Flow Legend
Process Flow
Gaseous or Emissions Flow

Revised:
December 8, 2023
Project # 231801.0128

Trinity Consultants
909 Wright's Summit Pkwy, Suite 230
Covington, KY 41011

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APPENDIX B. DEP7007 SERIES FORMS

The following DEP7007 series air permit application forms are included with this permit application:

1. DEP7007AI – Administrative Information
2. DEP700DD – Insignificant Activities
3. Acid Rain Renewal Form

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Division for Air Quality

300 Sower Boulevard

Frankfort, KY 40601

(502) 564-3999

DEP7007AI

Administrative Information

___ Section AI.1: Source Information

___ Section AI.2: Applicant Information

___ Section AI.3: Owner Information

___ Section AI.4: Type of Application

___ Section AI.5: Other Required Information

___ Section AI.6: Signature Block

___ Section AI.7: Notes, Comments, and Explanations

Additional Documentation

None

___ Additional Documentation attached

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)

KY EIS (AFS) #: 21- 167-00001

Permit #: V-17-030 R1

Agency Interest (AI) ID: 3148

Date: 12/6/2023

Section AI.1: Source Information

Physical Location Address:	**Street:**	815 Dix Dam Road				
	City:	Harrodsburg	**County**	Mercer	**Zip Code:**	40330
Mailing Address:	**Street or P.O. Box:**	32010				
	City:	Louisville	**State:**	Kentucky	**Zip Code:**	40232

Standard Coordinates for Source Physical Location

Longitude: -84.715263 (decimal degrees) **Latitude:** 37.789261 (decimal degrees)

Primary (NAICS) Category: Fossil Fuel Electric Power **Primary NAICS #:** 221112

Classification (SIC) Category: Electric Services **Primary SIC #:** 4911

Briefly discuss the type of business conducted at this site: Electric generating power plant. Existing operations consist of one pulverized coal utility boiler and associated raw material and support operations, and seven simple cycle peaking turbines.

Description of Area Surrounding Source: ☑ Rural Area ☐ Industrial Park ☐ Residential Area ☐ Urban Area ☐ Industrial Area ☐ Commercial Area

Is any part of the source located on federal land? ☐ Yes ☑ No

Number of Employees: Approximately 95

Approximate distance to nearest residence or commercial < 1 mile

Property Area: 1,222.1 acres

Is this source portable? ☐ Yes ☑ No

What other environmental permits or registrations does this source currently hold or need to obtain in Kentucky?

NPDES/KPDES:	☑ Currently Hold	☐ Need	☐ N/A
Solid Waste:	☑ Currently Hold	☐ Need	☐ N/A
RCRA:	☑ Currently Hold	☐ Need	☐ N/A
UST:	☐ Currently Hold	☐ Need	☑ N/A

Type of Regulated Waste Activity:

☐ Mixed Waste Generator ☑ Generator ☐ Recycler ☐ Other: _____

☐ U.S. Importer of Hazardous Waste ☐ Transporter ☐ Treatment/Storage/Disposal Facility ☐ N/A

Section AI.2: Applicant Information

Applicant Name: Kentucky Utilities Company (E.W. Brown Generating Station)

Title: (if individual)

Mailing Address: **Street or P.O. Box:** P.O. Box 32010
City: Louisville **State:** KY **Zip Code:** 40232

Email: (if individual) Not Applicable

Phone: 502-627-2343

Technical Contact

Name: Brandan Burfict

Title: Manager, Environmental Air

Mailing Address: **Street or P.O. Box:** P.O. Box 32010
City: Louisville **State:** KY **Zip Code:** 40232

Email: brandan.burfict@lge-ku.com

Phone: 502-627-2791

Air Permit Contact for Source

Name: Same as Technical Contact

Title:

Mailing Address: **Street or P.O. Box:**
City: **State:** **Zip Code:**

Email:

Phone:

Section AI.3: Owner Information

☑ **Owner same as applicant**

Name:

Title:

Mailing Address: **Street or P.O. Box:**

City: **State:** **Zip Code:**

Email:

Phone:

List names of owners and officers of the company who have an interest in the company of 5% or more.

Name	Position
LG&E and KU Energy LLC owns 100% common stock of Louisville Gas & Electric Company and Kentucky Utilities Company	

Section AI.4: Type of Application

Current Status: ☑ Title V ☐ Conditional Major ☐ State-Origin ☐ General Permit ☐ Registration ☐ None

Requested Action: *(check all that apply)*

☐ Name Change	☐ Initial Registration	☐ Significant Revision	☐ Administrative Permit Amendment
☑ Renewal Permit	☐ Revised Registration	☐ Minor Revision	☐ Initial Source-wide Operating Permit
☐ 502(b)(10)Change	☐ Extension Request	☐ Addition of New Facility	☐ Portable Plant Relocation Notice
☐ Revision	☐ Off Permit Change	☐ Landfill Alternate Compliance Submittal	☐ Modification of Existing Facilities
☐ Ownership Change	☐ Closure		

Requested Status: ☑ Title V ☐ Conditional Major ☐ State-Origin ☐ PSD ☐ NSR ☐ Other: _____

Is the source requesting a limitation of potential emissions? ☐ Yes ☑ No

Pollutant:	Requested Limit:	Pollutant:	Requested Limit:
☐ Particulate Matter		☐ Single HAP	
☐ Volatile Organic Compounds (VOC)		☐ Combined HAPs	
☐ Carbon Monoxide		☐ Air Toxics (40 CFR 68, Subpart F)	
☐ Nitrogen Oxides		☐ Carbon Dioxide	
☐ Sulfur Dioxide		☐ Greenhouse Gases (GHG)	
☐ Lead		☐ Other	

For New Construction:

Proposed Start Date of Construction: *(MM/YYYY)* N/A

Proposed Operation Start-Up Date: *(MM/YYYY)* N/A

For Modifications:

Proposed Start Date of Modification: *(MM/YYYY)* N/A

Proposed Operation Start-Up Date: *(MM/YYYY)* N/A

Applicant is seeking coverage under a permit shield. ☑ **Yes** ☐ **No**

Identify any non-applicable requirements for which permit shield is sought on a separate attachment to the application.

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Section AI.5 Other Required Information

Indicate the documents attached as part of this application:

☐ DEP7007A Indirect Heat Exchangers and Turbines	☐ DEP7007CC Compliance Certification	See CY2022 ACC
☐ DEP7007B Manufacturing or Processing Operations	☑ DEP7007DD Insignificant Activities	
☐ DEP7007C Incinerators and Waste Burners	☐ DEP7007EE Internal Combustion Engines	
☐ DEP7007F Episode Standby Plan	☐ DEP7007FF Secondary Aluminum Processing	
☐ DEP7007J Volatile Liquid Storage	☐ DEP7007GG Control Equipment	
☐ DEP7007K Surface Coating or Printing Operations	☐ DEP7007HH Haul Roads	
☐ DEP7007L Mineral Processes	☐ Confidentiality Claim	
☐ DEP7007M Metal Cleaning Degreasers	☐ Ownership Change Form	
☐ DEP7007N Source Emissions Profile	☐ Secretary of State Certificate	
☐ DEP7007P Perchloroethylene Dry Cleaning Systems	☑ Flowcharts or diagrams depicting process	
☐ DEP7007R Emission Offset Credit	☐ Digital Line Graphs (DLG) files of buildings, roads, etc.	
☐ DEP7007S Service Stations	☐ Site Map On file with KDAQ	
☐ DEP7007T Metal Plating and Surface Treatment Operations	☑ Map or drawing depicting location of facility	
☐ DEP7007V Applicable Requirements and Compliance Activities	☐ Safety Data Sheet (SDS)	
☐ DEP7007Y Good Engineering Practice and Stack Height Determination	☐ Emergency Response Plan	
☐ DEP7007AA Compliance Schedule for Non-complying Emission Units	☑ Other: Application Report	
☐ DEP7007BB Certified Progress Report	Acid Rain Permit Application	

Section AI.6: Signature Block

I, the undersigned, hereby certify under penalty of law, that I am a responsible official*, and that I have personally examined, and am familiar with, the 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 information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

DocuSigned by:
Steven B. Turner
8AD047306F3F4A8...

Authorized Signature

12/8/2023 | 8:47 AM EST

Date

Steven Turner

Type or Printed Name of Signatory

Vice President, Power Production

Title of Signatory

*Responsible official as defined by 401 KAR 52:001.

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Section AI.7: Notes, Comments, and Explanations

Clarification of AI.1 Permits/Registrations:
Kentucky Division of Waste Management Certificate of Registration-EPA ID #KYD-000-622-951
Kentucky Division of Water KPDES Permit #KY 0002020
US DOT Hazardous Material Certificate of Registration # 060619550228B
KY Division of Waste Management, Special Waste Landfill Permit (#SW 084-00010)

Division of Waste Management Certificate of Registration annual renewal
KPDES Permit Renewal every five years
US DOT Hazardous Material Certificate of Registration annual renewal

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Division for Air Quality
300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007DD

Insignificant Activities

___ Section DD.1: Table of Insignificant Activities
___ Section DD.2: Signature Block
___ Section DD.3: Notes, Comments, and Explanations

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AFS 21- 167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: 12/6/2023

Section DD.1: Table of Insignificant Activities

*Identify each activity with a unique Insignificant Activity number (IA #); for example: 1, 2, 3… etc.

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
1	Station fuel-oil tanks (2 @ 1,100,000 gallons each)	T-1 & T-2 (South CT area)	NA	VOC: 0.20 tpy
2	#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973	T-10 525,000 (Fuel oil Storage & Unit 3 Light off Tank)	NA	VOC: 0.10 tpy
3	Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each)	T-17 & T-18 (Steam Plant/Unit 3 Clean/Dirty Turbine Oil)	NA	VOC: <0.01 tpy
4	Unleaded gasoline storage tanks	T-25 (Coal Yard/Tractor Garage Area)	NA	VOC: 0.10 tpy

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
5	Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons)	R3, R6, R7	NA	VOC: <0.01 tpy
6	Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons)	R8, R9, R10, R11	NA	VOC: <0.01 tpy
7	Burning of Off-Specification Used Oil for Energy Recovery		401 KAR 61:020	
8	Kerosene Tank (500 gallons)	T-26 (Coal Yard/Tractor Garage Area)	NA	VOC: <0.01 tpy
9	Distillate Oil and/or Propane Coal Belt Heaters		NA	
10	Limestone Storage Pile		401 KAR 63.010	PM: 0.134 tpy PM10: 0.067 tpy PM2.5: 0.010 tpy
11	Limestone Reclaim Maintenance Tunnel Exhaust Vent		401 KAR 59:010	PM: 0.050 tpy PM10: 0.017 tpy PM2.5: <0.01 tpy
12	Sorbent Storage Silos (for SO3 mitigation)		401 KAR 59:010	PM/PM10/PM2.5: <0.01 tpy
13	Natural Gas Distillate tank (2,000 gallons)	T-9 (CT area)	NA	VOC: 0.20 tpy
14	Diesel Fuel tanks for emergency generators (3 @ 391 gallons)	T3, T4, T5 (CT area/Emergency Generators)	NA	VOC: <0.01 tpy
15	Diesel Fuel tank for emergency fire pump (300 gallons)	T-8 (CT area/emergency fire pump AST)	NA	VOC: <0.01 tpy
16	Liquid Hg Control Additives		NA	

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
17	Diesel Fuel tank for emergency generator (837 gallons)	T-14 (Steam Plant/Unit 3 Emergency Generator)	NA	VOC: <0.01 tpy
18	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons)	T-20, T-21 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)	NA	VOC: <0.01 tpy
19	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons)	T-22, T-23 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)	NA	VOC: <0.01 tpy
20	Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons)	R4, R44	NA	VOC: <0.01 tpy
21	Turbine oil reservoir for Unit 3 seal oil (150 gallons)	R14	NA	VOC: <0.01 tpy
22	Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons)	R18, R19 (Unit 3, outside out of service ESP)	NA	VOC: <0.01 tpy
23	Lab Fume Hood		NA	
24	Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons)	T27, T28, T29 (Tractor Garage Building Read Area)	NA	VOC: <0.01 tpy
25	PAC Storage Silos		401 KAR 59:010	PM/PM10/PM2.5: <0.01 tpy
26	Bottom Ash Transport		401 KAR 63.010	
27	Fly Ash Transport		401 KAR 63.010	
28	Gypsum Transport & Process Water System Solids		401 KAR 63.010	PM: 0.842 tpy PM10: 0.168 tpy PM2.5: 0.041 tpy

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
29	Landfill Truck Loading and Unloading & Process Water System Solids		401 KAR 63.010	PM: 0.126 tpy PM10: 0.060 tpy PM2.5: <0.01 tpy
30	Active Area of the CCR Landfill & Process Water System Solids (Wind Erosion)		401 KAR 63.010	PM: 1.18 tpy PM10: 0.589 tpy PM2.5: 0.088 tpy
31	Slipstream Carbon Dioxide (CO2) capture System – Research		401 KAR 63.010	PM/PM10/PM2.5: <0.01 tpy
32	Bottom Ash Handling including storage pile (associated with CCR landfill operations)		401 KAR 63.010	PM: 0.050 tpy PM10: 0.025 tpy PM2.5: <0.01 tpy
33	Fly Ash Handling including load out to trucks (associated with CCR landfill operations)		401 KAR 63.010	PM: 0.911 tpy PM10: 0.431 tpy PM2.5: 0.065 tpy
34	Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)		401 KAR 63.010	PM/PM10: 0.863 tpy PM2.5: 0.604 tpy
35	Fly Ash Storage Silos (2) (associated with CCR landfill operations)		401 KAR 59.010	PM/PM10: 0.691 tpy PM2.5: 0.484 tpy
36	Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)		401 KAR 63.010	PM: 0.232 tpy PM10: 0.113 tpy PM2.5: 0.017 tpy
37	NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)		NA	

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
38	Diesel Fuel tanks for emergency generators (2 @ 900 gallons)	T-6, T-7 CT area/between CT7 & CT8(EU28 & EU25)	NA	VOC: <0.01 tpy
39	Diesel Fuel Tanks (500, 2000, 3@ 550, 1100 gallons)	T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)	NA	VOC: <0.01 tpy
40	Mobile Diesel Fuel Tank (251 gallons/square tank)	T-39 (Stored in CT Warehouse when not in use)	NA	VOC: <0.01 tpy
44	**Unit 3 Propylene Glycol Tank (3,000 gal)**		**NA**	**VOC: <0.01 tpy**
45	**Hydroelectric Building Lube Oil Tanks (T-31 and T-32)**		**NA**	**VOC: <0.01 tpy**
46	**CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)**		**NA**	**Negligible**
47	**Unit 3 Hydrazine Monohydrate Tote (180 gal)**		**NA**	**Negligible**
48	**Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)**		**401 KAR 59:010**	**PM/PM10/PM2.5: 0.75 tpy**
	NOTE: Blue font are existing IAs. New Insignificant Activities being added to Section C of the Title V permit via the Title V permit renewal are shown in green font.			

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions

Section DD.2: Signature Block

I, THE UNDERSIGNED, HEREBY CERTIFY UNDER PENALTY OF LAW, THAT I AM A RESPONSIBLE OFFICIAL, AND THAT I HAVE PERSONALLY EXAMINED, AND AM FAMILIAR WITH, THE 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 INFORMATION IS ON KNOWLEDGE AND BELIEF, TRUE, ACCURATE, AND COMPLETE. I AM AWARE THAT THERE ARE SIGNIFICANT PENALTIES FOR SUBMITTING FALSE OR INCOMPLETE INFORMATION, INCLUDING THE POSSIBILITY OF FINE OR IMPRISONMENT.

By:	DocuSigned by: Steven B. Turner 8AD647306F3F4A0...	12/8/2023 | 8:47 AM EST
	Authorized Signature	**Date**
	Steven Turner	Vice President, Power Production
	Type/Print Name of Signatory	**Title of Signatory**

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Section DD.3: Notes, Comments, and Explanations
Insignificant Activities listed on the form in blue font are existing. New Insignificant Activities being added to Section C of the Title V permit via the Title V permit renewal application in green font.
Refer to prior applications for emission calculations for existing insignificant activities.

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United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2012

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.

Facility (Source) Name	State	Plant Code
E.W. Brown Station	KY	001355

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)
Unit 3 (Emission Unit 03)	Yes
Units 5-11 (Emission Units 23-29)	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

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Facility (Source) Name (from STEP 1)

Permit Requirements

STEP 3

Read the standard 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).

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Facility (Source) Name (from STEP 1)

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(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.

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

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Facility (Source) Name (from STEP 1)

of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(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.

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

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any other provision of the Act, including the provisions of title I of the Act relating

STEP 3, Cont'd.

Effect on Other Authorities, Cont'd.

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 Cynthia Whitaker	
Signature DocuSigned by: Cindy Whitaker 6193ECDCA946493...	Date 12/7/2023 | 12:52 PM EST

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APPENDIX C. EMISSIONS UNIT INDEX AND CALCULATIONS

An inventory of existing emission units at the Brown Station is provided in this appendix along with documentation showing the methodology for defining potential emissions from the new IAs being permitted with this renewal application. Additionally, KU has included a facility-wide PTE summary for criteria pollutants, total HAP, and select individual HAP.

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C.1. Brown Station Emission Unit Index

> The following table provides an index of existing emission units at the E.W. Brown Station along with new emission units requested for addition to the Title V permit upon permit renewal.
> The emission unit ID nomenclature listed for the new emission units (shown in green font) are placeholders, to be finalized by KDAQ upon issuance of an amended Title V operating permit.

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID
35	AREA2	35	1	Paved and Unpaved Roads	Roadways	Dust Suppression		Fugitive
50	AREA4	EU 50	1	CCR Landfill Operations and Haul Trucks	Paved Empty Bottom Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	2	CCR Landfill Operations and Haul Trucks	Paved Full Fly Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	3	CCR Landfill Operations and Haul Trucks	Paved Empty Gypsum Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	4	CCR Landfill Operations and Haul Trucks	Paved Full Bottom Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	5	CCR Landfill Operations and Haul Trucks	Paved Empty Fly Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	6	CCR Landfill Operations and Haul Trucks	Paved Full Gypsum Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	7	CCR Landfill Operations and Haul Trucks	Unpaved Empty Bottom Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	8	CCR Landfill Operations and Haul Trucks	Unpaved Full Bottom Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	9	CCR Landfill Operations and Haul Trucks	Unpaved Empty Fly Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	10	CCR Landfill Operations and Haul Trucks	Unpaved Full Fly Ash Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	11	CCR Landfill Operations and Haul Trucks	Unpaved Empty Gypsum Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	12	CCR Landfill Operations and Haul Trucks	Unpaved Full Gypsum Transport	Dust Suppression		Fugitive
50	AREA4	EU 50	13	CCR Landfill Operations and Haul Trucks	Travel Heavy Equip. Landfill	Dust Suppression		Fugitive
3	COMB3	003	1	Unit 3 Indirect Heat Exchanger	Coal	LowNOX; SCR; PJFF; FGD	C03A, B, E, D	17
3	COMB3	003	2	Unit 3 Indirect Heat Exchanger	#2 Fuel Oil	None		17
23	COMB4	23	1	Combustion Turbine #9	Distillate Oil	CT9 Water Injection	C23	23
23	COMB4	23	2	Combustion Turbine #9	Natural Gas	CT9 Water Injection	C23	23
24	COMB5	24	1	Combustion Turbine #10	Distillate Oil	CT10 Water Injection	C24	24
24	COMB5	24	2	Combustion Turbine #10	Natural Gas	CT10 Water Injection	C24	24
25	COMB6	25	1	Combustion Turbine #8	Distillate Oil	CT8 Water Injection	C25	25
25	COMB6	25	2	Combustion Turbine #8	Natural Gas	CT8 Water Injection	C25	25
26	COMB7	26	1	Combustion Turbine #11	Distillate Oil	CT11 Water Injection	C26	26
26	COMB7	26	2	Combustion Turbine #11	Natural Gas	CT11 Water Injection	C26	26
27	COMB8	27	1	Combustion Turbine #6	Distillate Oil	CT6 Water Injection	C27	27
27	COMB8	27	2	Combustion Turbine #6	Natural Gas	LowNOX Burners	C27	27
28	COMB9	28	1	Combustion Turbine #7	Distillate Oil	CT7 Water Injection	C28	28
28	COMB9	28	2	Combustion Turbine #7	Natural Gas	LowNOX Burners	C28	28
29	COMB10	29	1	Combustion Turbine #5	Natural Gas	CT5 Water Injection	C29	29
39	COMB11	39	1	Dix Dam Crest Gate Emergency Generator (40 HP)	Gasoline			39
40	COMB12	40	1	Brown Station Emergency Generator (135 HP)	Diesel			40
41	COMB12	41	1	CT5 Emergency Generator (308 HP)	Diesel			41
42	COMB12	42	1	CT6 Emergency Generator (230 HP)	Diesel			42
43	COMB12	43	1	CT7 Emergency Generator (230 HP)	Diesel			43
44	COMB12	44	1	CT Area Fire Pump Engine (208 HP)	Diesel			44
45	COMB13	45	1	Steam Plant Emergency Fire Pump Engine #1 (375 HP)	Diesel			45
46	COMB13	46	1	Steam Plant Emergency Fire Pump Engine #2 (375 HP)	Diesel			46
47	COMB14	47	1	Emergency Quench Water Pump Engine #1 (485 HP)	Diesel			47
48	COMB14	48	1	Emergency Quench Water Pump Engine #2 (485 HP)	Diesel			48
49	COMB15	49	1	Generac Emergency Engine (752 HP)	Diesel			49
55	COMB16	EU 55	1	2.4 MMBtu/hr Natural Gas Process Heaters	Natural Gas			55

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Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID
56	COMB17	EU 56	1	7.0 MMBtu/hr Natural Gas Process Heaters	Natural Gas			56
57	COMB18	EU 57	1	7.0 MMBtu/hr Natural Gas Process Heaters	Natural Gas			57
16	EQPT1	16	1	Coal Crushing	Four Crushers and Crusher House	Wet Scrubber	C16	16-1
21 (16)	EQPT2	21	1	Dry Fly Ash Handling	Dry Fly Ash Collection and Silo	PJFF	C21	21
7-1	EQPT14	07	1	Coal Handling Operations 07	West Track Hopper	Enclosures	C07A	Fugitive
7-2	EQPT14	07	2	Coal Handling Operations 07	Conveyor A-1	Enclosures	C07B	Fugitive
7-3	EQPT14	07	3	Coal Handling Operations 07	Conveyor E	Enclosures	C07C	Fugitive
7-4	EQPT14	07	4	Coal Handling Operations 07	Conveyor F	Enclosures	C07D	Fugitive
7-5	EQPT14	07	5	Coal Handling Operations 07	Conveyor G	Enclosures	C07E	Fugitive
7-6	EQPT14	07	6	Coal Handling Operations 07	Conveyor H	Enclosures	C07F	Fugitive
9-1	EQPT15	09	1	Coal Handling Operations 09	East Track Hopper	Enclosures	C09A	Fugitive
9-2	EQPT15	09	2	Coal Handling Operations 09	Conveyor A	Enclosures	C09B	Fugitive
9-3	EQPT15	09	3	Coal Handling Operations 09	Conveyor B	Enclosures	C09C	Fugitive
9-4	EQPT15	09	4	Coal Handling Operations 09	Conveyor C	Enclosures	C09D	Fugitive
9-5	EQPT15	09	5	Coal Handling Operations 09	Conveyor J	Enclosures	C09E	Fugitive
9-6	EQPT15	09	6	Coal Handling Operations 09	Coal Stockpile	Dust Suppression	C09F	Fugitive
13-1	EQPT16	13	1	Coal Handling Operations 13	Conveyor D [Tripper for Units 1 & 2]	Enclosure	C13A	13
13-2	EQPT16	13	2	Coal Handling Operations 13	Conveyor K-1 [Upper Tripper for Unit 3]	Fabric Filter	C13B	14
13-3	EQPT16	13	3	Coal Handling Operations 13	Conveyor K [Lower Tripper for Unit 3]	Fabric Filter	C13C	15
30	EQPT17	30-31	1	Limestone Unloading	Limestone Truck Dump Station #1	Fabric Filter	C30	30
31	EQPT17	30-31	2	Limestone Unloading	Limestone Truck Dump Station #2	Fabric Filter	C31	31
32	EQPT18	32-34	1	Limestone Handling	Limestone Stacking Tube	Fabric Filter	C32	32
33-34	EQPT18	32-34	2	Limestone Handling	Limestone Reclaim Conveyor #1 & 2	Fabric Filter	C33	33
38	EQPT19	36-38	3	Cooling Tower 3 (Forced Draft)	Unit 3 Cooling Tower with Drift Eliminators	Drift Eliminators		36
51 & 52	EQPT20	51	1	2 Cummins Emergency Engines (1220 HP Each)	Diesel			51
IA-01				Station fuel-oil tanks (2 @ 1,100,000 gallons each) - T-1 & T-2 (South CT area)				
IA-02				#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973 - T-10 525,000 (Fuel oil Storage & Unit 3 Light off Tank)				
IA-03				Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each) - T-17 & T-18 (Steam Plant/Unit 3 Clean/Dirty Turbine Oil)				
IA-04				Unleaded gasoline storage tanks - T-25(Coal Yard/Tractor Garage Area)				
IA-05				Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons) - R3, R6, R7				
IA-06				Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons) - R8, R9, R10, R11				
IA-07				Burning of Off-Specification Used Oil for Energy Recovery				
IA-08				Kerosene Tank (500 gallons) - T-26 (Coal Yard/Tractor Garage Area)				
IA-09				Distillate Oil and/or Propane Coal Belt Heaters				
IA-10				Limestone Storage Pile				
IA-11				Limestone Reclaim Maintenance Tunnel Exhaust Vent				
IA-12				Sorbent Storage Silos (for SO3 mitigation)				
IA-13				Natural Gas Distillate tank (2,000 gallons) - T-9 (CT area)				
IA-14				Diesel Fuel tanks for emergency generators (3 @ 391 gallons) - T3, T4, T5 (CT area/Emergency Generators)				
IA-15				Diesel Fuel tank for emergency fire pump (300 gallons) - T-8 (CT area/emergency fire pump AST)				
IA-16				Liquid Hg Control Additives				
IA-17				Diesel Fuel tank for emergency generator (837 gallons) - T-14 (Steam Plant/Unit 3 Emergency Generator)				
IA-18				Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons) - T-20, T-21 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)				
IA-19				Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons) - T-22, T-23 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)				
IA-20				Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons) - R4, R44				

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID
IA-21				Turbine oil reservoir for Unit 3 seal oil (150 gallons) - R14				
IA-22				Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons) - R18, R19 (Unit 3, outside out of service ESP)				
IA-23				Lab Fume Hood				
IA-24				Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons) - T27, T28, T29 (Tractor Garage Building Read Area)				
IA-25				PAC Storage Silos				
IA-26				Bottom Ash Transport				
IA-27				Fly Ash Transport				
IA-28				Gypsum Transport & Process Water System Solids				
IA-29				Landfill Truck Loading and Unloading & Process Water System Solids				
IA-30				Active Area of the CCR Landfill & Process Water System Solids (Wind Erosion)				
IA-31				Slipstream Carbon Dioxide (CO2) capture System – Research				
IA-32				Bottom Ash Handling including storage pile (associated with CCR landfill operations)				
IA-33				Fly Ash Handling including load out to trucks (associated with CCR landfill operations)				
IA-34				Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)				
IA-35				Fly Ash Storage Silos (2) (associated with CCR landfill operations)				
IA-36				Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)				
IA-37				NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)				
IA-38				Diesel Fuel tanks for emergency generators (2 @ 900 gallons) - T-6, T-7 CT area/between CT7 & CT8(EU28 & EU25)				
IA-39				Diesel Fuel Tanks (500, 2000, 3@ 550, 1100 gallons) - T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)				
IA-40				Mobile Diesel Fuel Tank (251 gallons/square tank) - T-39 (Stored in CT Warehouse when not in use)				
IA-44				**Unit 3 Propylene Glycol Tank (3,000 gal)**				
IA-45				**Hydroelectric Building Lube Oil Tanks (T-31 and T-32)**				
IA-46				**CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)**				
IA-47				**Unit 3 Hydrazine Monohydrate Tote (180 gal)**				
IA-48				**Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)**				

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C.2. Facility-Wide Potential Emissions Summary

> The table below tallies the potential to emit for all emission units currently permitted for relevant regulated air pollutants.

KyEIS Equip ID	KyEIS Source ID	Description	KyEIS Process ID	Process Description	PM (tpy)	PM10 (tpy)	PM2.5 (tpy)	NOX (tpy)	CO (tpy)	VOC (tpy)	SO2 (tpy)	H2SO4 (tpy)	Lead (tpy)	CO2e (tpy)	Total HAP (tpy)
AREA2	35	Paved and Unpaved Roads	1	Roadways	27.04	5.72	0.74	0	0	0	0	0	0	0	0
AREA4	50	CCR Landfill Operations and Haul Trucks	1-13	Process IDs 1-13	13.34	3.20	0.36	0	0	0	0	0	0	0	0
COMB3	50	Unit 3 Indirect Heat Exchanger	1	Coal	696.42	696.42	309.52	1,187	527.59	63.31	2,438	478.17	0.15	4,812,320	321.86
COMB4	23	Combustion Turbine #9	1	Distillate Oil	20.67	20.67	20.67	105.65	5.68	0.71	86.98	0	0.02	279,776	2.19
COMB4	23	Combustion Turbine #9	2	Natural Gas	39.55	39.55	39.55	238.33	252.60	12.58	0.49	0	0	701,626	6.16
COMB5	24	Combustion Turbine #10	1	Distillate Oil	20.67	20.67	20.67	105.65	5.68	0.71	86.98	0	0.02	279,776	2.19
COMB5	24	Combustion Turbine #10	2	Natural Gas	39.55	39.55	39.55	238.33	252.60	12.58	0.49	0	0	701,626	6.16
COMB6	25	Combustion Turbine #8	1	Distillate Oil	20.67	20.67	20.67	105.65	5.68	0.71	86.98	0	0.02	279,776	2.19
COMB6	25	Combustion Turbine #8	2	Natural Gas	39.55	39.55	39.55	238.33	252.60	12.58	0.49	0	0	701,626	6.16
COMB7	26	Combustion Turbine #11	1	Distillate Oil	20.67	20.67	20.67	105.65	5.68	0.71	86.98	0	0.02	279,776	2.19
COMB7	26	Combustion Turbine #11	2	Natural Gas	39.55	39.55	39.55	238.33	252.60	12.58	0.49	0	0	701,626	6.16
COMB8	27	Combustion Turbine #6	1	Distillate Oil	25.35	25.35	25.35	145.23	6.97	0.87	490.78	0	0.02	343,176	2.69
COMB8	27	Combustion Turbine #6	2	Natural Gas	48.51	48.51	48.51	251.03	309.84	15.43	0.60	0	0	860,620	7.55
COMB9	28	Combustion Turbine #7	1	Distillate Oil	25.35	25.35	25.35	145.23	6.97	0.87	490.78	0	0.02	343,176	2.69
COMB9	28	Combustion Turbine #7	2	Natural Gas	48.51	48.51	48.51	251.03	309.84	15.43	0.60	0	0	860,620	7.55
COMB10	29	Combustion Turbine #5	1	Natural Gas	39.55	39.55	39.55	238.33	252.60	12.58	0.49	0	0	701,626	6.16
COMB11	39	Dix Dam Crest Gate Emergency Generator (40 HP)	1	Gasoline	1.44E-03	1.44E-03	1.44E-03	0.02	0.01	0.04	2.36E-06	0	0	3.05	0
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	0.01	0.01	0.01	0.21	0.05	0.02	7.16E-05	0	0	7.73	1.79E-04
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	0.03	0.03	0.03	0.48	0.10	0.04	1.63E-04	0	0	17.64	4.09E-04
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	0.03	0.03	0.03	0.36	0.08	0.03	1.22E-04	0	0	13.17	3.05E-04
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	0.03	0.03	0.03	0.36	0.08	0.03	1.22E-04	0	0	13.17	3.05E-04
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	0.02	0.02	0.02	0.32	0.07	0.03	1.10E-04	0	0	11.91	2.76E-04
COMB13	45	Steam Plant Emergency Fire Pump Engine #1 (375 HP)	1	Diesel	0.02	0.02	0.02	0.30	0.11	0.02	1.99E-04	0	0	21.47	4.97E-04
COMB13	45	Steam Plant Emergency Fire Pump Engine #1 (375 HP)	1	Diesel	0.02	0.02	0.02	0.30	0.11	0.02	1.99E-04	0	0	21.47	4.97E-04
COMB14	47	Emergency Quench Water Pump Engine #1 (485 HP)	1	Diesel	0.01	0.01	0.01	0.39	0.27	0.03	2.57E-04	0	0	27.77	6.43E-04
COMB14	47	Emergency Quench Water Pump Engine #1 (485 HP)	1	Diesel	0.01	0.01	0.01	0.39	0.27	0.03	2.57E-04	0	0	27.77	6.43E-04
COMB15	49	Generac Emergency Engine (752 HP)	1	Diesel	0.02	0.02	0.02	0.52	0.29	0.02	3.99E-04	0	0	43.06	9.98E-04
COMB16	EU 55	2.4 MMBtu/hr Natural Gas Process Heaters	1	Natural Gas	0.08	0.08	0.02	1.00	0.84	0.05	5.99E-03	4.58E-04	4.99E-06	1,231	0.02
COMB17	EU 56	7.0 MMBtu/hr Natural Gas Process Heaters	1	Natural Gas	0.22	0.22	0.06	2.91	2.45	0.16	0.02	1.34E-03	1.46E-05	3,590	0.05
COMB18	EU 57	7.0 MMBtu/hr Natural Gas Process Heaters	1	Natural Gas	0.22	0.22	0.06	2.91	2.45	0.16	0.02	1.34E-03	1.46E-05	3,590	0.05
EQPT1	16	Coal Crushing	1	Four Crushers and Crusher House	1.44	0.72	0.14	0	0	0	0	0	0	0	0
EQPT2	21	Dry Fly Ash Handling	1	Dry Fly Ash Collection and Silo	1.04	1.04	0.21	0	0	0	0	0	0	0	0
EQPT14	07	Coal Handling Operations 07	1-6	Process IDs 1-6	0.68	0.68	0.14	0	0	0	0	0	0	0	0
EQPT15	09	Coal Handling Operations 09	1-6	Process IDs 1-6	4.66	2.64	0.52	0	0	0	0	0	0	0	0
EQPT16	13	Coal Handling Operations 13	1-3	Process IDs 1-3	13.04	13.04	2.61	0	0	0	0	0	0	0	0
EQPT17	30-31	Limestone Unloading	1-2	Process IDs 1-2	2.92	2.92	0.58	0	0	0	0	0	0	0	0
EQPT18	32-34	Limestone Handling	1-2	Process IDs 1-2	2.17	2.17	0.43	0	0	0	0	0	0	0	0
EQPT19	36-38	Cooling Tower 3 (Forced Draft)	3	Unit 3 Cooling Tower with Drift Eliminators	3.06	3.06	3.06	0	0	0	0	0	0	0	0
EQPT20	51	2 Cummins Emergency Engines (1220 HP Each)	1	Diesel	6.72E-03	6.72E-03	6.72E-03	0.79	0.03	0.02	6.47E-04	0	0	69.86	1.62E-03

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KyEIS Equip ID	KyEIS Source ID	Description	KyEIS Process ID	Process Description	PM (tpy)	PM10 (tpy)	PM2.5 (tpy)	NOX (tpy)	CO (tpy)	VOC (tpy)	SO2 (tpy)	H2SO4 (tpy)	Lead (tpy)	CO2e (tpy)	Total HAP (tpy)
IA-01		Station fuel-oil tanks (2 @ 1,100,000 gallons each) - T-1 & T-2 (South CT area)	na	na	0	0	0	0	0	0.20	0	0	0	0	0
IA-02		#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973 - T-10 525,000 (Fuel oil Storage & Unit 3 Light off Tank)	na	na	0	0	0	0	0	0.10	0	0	0	0	0
IA-03		Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each) - T-17 & T-18 (Steam Plant/Unit 3 Clean/Dirty Turbine Oil)	na	na	0	0	0	0	0	2.10E-03	0	0	0	0	0
IA-04		Unleaded gasoline storage tanks - T-25 (Coal Yard/Tractor Garage Area)	na	na	0	0	0	0	0	0.10	0	0	0	0	0
IA-05		Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons) - R3, R6, R7	na	na	0	0	0	0	0	1.52E-03	0	0	0	0	0
IA-06		Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons) - R8, R9, R10, R11	na	na	0	0	0	0	0	9.32E-04	0	0	0	0	0
IA-07		Burning of Off-Specification Used Oil for Energy Recovery	na	na	0	0	0	0	0	0	0	0	0	0	0
IA-08		Kerosene Tank (500 gallons) - T-26 (Coal Yard/Tractor Garage Area)	na	na	0	0	0	0	0	1.07E-04	0	0	0	0	0
IA-09		Distillate Oil and/or Propane Coal Belt Heaters	na	na	0	0	0	0	0	0	0	0	0	0	0
IA-10		Limestone Storage Pile	na	na	0.13	0.07	0.01	0	0	0	0	0	0	0	0
IA-11		Limestone Reclaim Maintenance Tunnel Exhaust Vent	na	na	0.05	0.02	2.50E-03	0	0	0	0	0	0	0	0
IA-12		Sorbent Storage Silos (for SO3 mitigation)	na	na	1.49E-03	5.10E-04	7.50E-05	0	0	0	0	0	0	0	0
IA-13		Natural Gas Distillate tank (2,000 gallons) - T-9 (CT area)	na	na	0	0	0	0	0	0.20	0	0	0	0	0
IA-14		Diesel Fuel tanks for emergency generators (3 @ 391 gallons) - T3, T4, T5 (CT area/Emergency Generators)	na	na	0	0	0	0	0	5.89E-05	0	0	0	0	0
IA-15		Diesel Fuel tank for emergency fire pump (300 gallons) - T-8 (CT area/emergency fire pump AST)	na	na	0	0	0	0	0	3.92E-05	0	0	0	0	0
IA-16		Liquid Hg Control Additives	na	na	0	0	0	0	0	0	0	0	0	0	0
IA-17		Diesel Fuel tank for emergency generator (837 gallons) - T-14 (Steam Plant/Unit 3 Emergency Generator)	na	na	0	0	0	0	0	1.54E-04	0	0	0	0	0
IA-18		Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons) - T-20, T-21 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)	na	na	0	0	0	0	0	7.04E-05	0	0	0	0	0
IA-19		Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons) - T-22, T-23 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)	na	na	0	0	0	0	0	9.59E-05	0	0	0	0	0
IA-20		Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons) - R4, R44	na	na	0	0	0	0	0	2.33E-04	0	0	0	0	0
IA-21		Turbine oil reservoir for Unit 3 seal oil (150 gallons) - R14	na	na	0	0	0	0	0	2.98E-05	0	0	0	0	0
IA-22		Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons) - R18, R19 (Unit 3, outside out of service ESP)	na	na	0	0	0	0	0	7.72E-05	0	0	0	0	0
IA-23		Lab Fume Hood	na	na	0	0	0	0	0	0	0	0	0	0	0

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KyEIS Equip ID	KyEIS Source ID	Description	KyEIS Process ID	Process Description	PM (tpy)	PM10 (tpy)	PM2.5 (tpy)	NOX (tpy)	CO (tpy)	VOC (tpy)	SO2 (tpy)	H2SO4 (tpy)	Lead (tpy)	CO2e (tpy)	Total HAP (tpy)
IA-24		Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons) - T27, T28, T29 (Tractor Garage Building Read Area)	na	na	0	0	0	0	0	1.25E-04	0	0	0	0	0
IA-25		PAC Storage Silos	na	na	1.49E-04	5.10E-05	7.50E-06	0	0	0	0	0	0	0	0
IA-26		Bottom Ash Transport	na	na	0	0	0	0	0	0	0	0	0	0	0
IA-27		Fly Ash Transport	na	na	0	0	0	0	0	0	0	0	0	0	0
IA-28		Gypsum Transport & Process Water System Solids	na	na	0.84	0.17	0.04	0	0	0	0	0	0	0	0
IA-29		Landfill Truck Loading and Unloading & Process Water System Solids	na	na	0.13	0.06	9.02E-03	0	0	0	0	0	0	0	0
IA-30		Active Area of the CCR Landfill & Process Water System Solids (Wind Erosion)	na	na	1.18	0.59	0.09	0	0	0	0	0	0	0	0
IA-31		Slipstream Carbon Dioxide (CO2) capture System – Research	na	na	5.70E-03	5.70E-03	5.70E-03	0	0	0	0	0	0	0	0
IA-32		Bottom Ash Handling including storage pile (associated with CCR landfill operations)	na	na	0.05	0.02	3.75E-03	0	0	0	0	0	0	0	0
IA-33		Fly Ash Handling including load out to trucks (associated with CCR landfill operations)	na	na	0.91	0.43	0.07	0	0	0	0	0	0	0	0
IA-34		Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)	na	na	0.86	0.86	0.60	0	0	0	0	0	0	0	0
IA-35		Fly Ash Storage Silos (2) (associated with CCR landfill operations)	na	na	0.69	0.69	0.48	0	0	0	0	0	0	0	0
IA-36		Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)	na	na	0.23	0.11	0.02	0	0	0	0	0	0	0	0
IA-37		NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)	na	na	0	0	0	0	0	0	0	0	0	0	0
IA-38		Diesel Fuel tanks for emergency generators (2 @ 900 gallons) - T-6, T-7 CT area/between CT7 & CT8(EU28 & EU25)	na	na	0	0	0	0	0	1.65E-04	0	0	0	0	0
IA-39		Diesel Fuel Tanks (500, 2000, 3@ 550, 1100 gallons) - T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)	na	na	0	0	0	0	0	3.67E-04	0	0	0	0	0
IA-40		Mobile Diesel Fuel Tank (251 gallons/square tank) - T-39 (Stored in CT Warehouse when not in use)	na	na	0	0	0	0	0	2.89E-05	0	0	0	0	0
IA-44		**Unit 3 Propylene Glycol Tank (3,000 gal)**	**na**	**na**	0	0	0	0	0	4.44E-05	0	0	0	0	0
IA-45		**Hydroelectric Building Lube Oil Tanks (T-31 and T-32)**	**na**	**na**	0	0	0	0	0	2.30E-05	0	0	0	0	0
IA-46		**CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)**	**na**	**na**	0	0	0	0	0	0	0	0	0	0	0
IA-47		**Unit 3 Hydrazine Monohydrate Tote (180 gal)**	**na**	**na**	0	0	0	0	0	0	0	0	0	0	0
IA-48		**Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)**	**na**	**na**	0.75	0.75	0.75	0	0	0	0	0	0	0	0
Total					**1,201**	**1,164**	**748.86**	**3,605**	**2,454**	**162.96**	**3,771**	**478.18**	**0.25**	**11,855,834**	**382.04**

KyEIS Equip ID	KyEIS Source ID	Description	KyEIS Process ID	Process Description	Benzene (tpy)	Formalde-hyde (tpy)	Hexane (tpy)	HCl (tpy)	HF (tpy)	Mercury (tpy)	Toluene (tpy)	Xylenes (tpy)
COMB3	003	Unit 3 Indirect Heat Exchanger	1	Coal	0.09	0.06	0	290.99	23.28	0.03	0.04	0.03
COMB4	23	Combustion Turbine #9	1	Distillate Oil	0.09	0.48	0	0	0	2.07E-03	0	0
COMB4	23	Combustion Turbine #9	2	Natural Gas	0.07	4.25	0	0	0	0	0.78	0.38
COMB5	24	Combustion Turbine #10	1	Distillate Oil	0.09	0.48	0	0	0	2.07E-03	0	0
COMB5	24	Combustion Turbine #10	2	Natural Gas	0.07	4.25	0	0	0	0	0.78	0.38
COMB6	25	Combustion Turbine #8	1	Distillate Oil	0.09	0.48	0	0	0	2.07E-03	0	0
COMB6	25	Combustion Turbine #8	2	Natural Gas	0.07	4.25	0	0	0	0	0.78	0.38
COMB7	26	Combustion Turbine #11	1	Distillate Oil	0.09	0.48	0	0	0	2.07E-03	0	0
COMB7	26	Combustion Turbine #11	2	Natural Gas	0.07	4.25	0	0	0	0	0.78	0.38
COMB8	27	Combustion Turbine #6	1	Distillate Oil	0.12	0.59	0	0	0	2.54E-03	0	0
COMB8	27	Combustion Turbine #6	2	Natural Gas	0.09	5.22	0	0	0	0	0.96	0.47
COMB9	28	Combustion Turbine #7	1	Distillate Oil	0.12	0.59	0	0	0	2.54E-03	0	0
COMB9	28	Combustion Turbine #7	2	Natural Gas	0.09	5.22	0	0	0	0	0.96	0.47
COMB10	29	Combustion Turbine #5	1	Natural Gas	0.07	4.25	0	0	0	0	0.78	0.38
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	4.41E-05	5.58E-05	0	0	0	0	1.93E-05	1.35E-05
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	4.41E-05	5.58E-05	0	0	0	0	1.93E-05	1.35E-05
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	4.41E-05	5.58E-05	0	0	0	0	1.93E-05	1.35E-05
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	4.41E-05	5.58E-05	0	0	0	0	1.93E-05	1.35E-05
COMB12	40	Brown Station Emergency Generator (135 HP)	1	Diesel	4.41E-05	5.58E-05	0	0	0	0	1.93E-05	1.35E-05
COMB13	45	Steam Plant Emergency Fire Pump Engine #1 (375 HP)	1	Diesel	1.22E-04	1.55E-04	0	0	0	0	5.37E-05	3.74E-05
COMB13	45	Steam Plant Emergency Fire Pump Engine #1 (375 HP)	1	Diesel	1.22E-04	1.55E-04	0	0	0	0	5.37E-05	3.74E-05
COMB14	47	Emergency Quench Water Pump Engine #1 (485 HP)	1	Diesel	1.58E-04	2.00E-04	0	0	0	0	6.94E-05	4.84E-05
COMB14	47	Emergency Quench Water Pump Engine #1 (485 HP)	1	Diesel	1.58E-04	2.00E-04	0	0	0	0	6.94E-05	4.84E-05
COMB15	49	Generac Emergency Engine (752 HP)	1	Diesel	2.46E-04	3.11E-04	0	0	0	0	1.08E-04	7.50E-05
COMB16	EU 55	2.4 MMBtu/hr Natural Gas Process Heaters	1	Natural Gas	1.80E-08	7.49E-04	0.02	0	0	2.60E-06	3.39E-05	0
COMB17	EU 56	7.0 MMBtu/hr Natural Gas Process Heaters	1	Natural Gas	5.24E-08	2.18E-03	0.05	0	0	7.57E-06	9.90E-05	0
COMB18	EU 57	7.0 MMBtu/hr Natural Gas Process Heaters	1	Natural Gas	5.24E-08	2.18E-03	0.05	0	0	7.57E-06	9.90E-05	0
EQPT20	51	2 Cummins Emergency Engines (1220 HP Each)	1	Diesel	3.98E-04	5.04E-04	0	0	0	0	1.75E-04	1.22E-04
Total					**1.24**	**34.89**	**0.12**	**290.99**	**23.28**	**0.04**	**5.85**	**2.89**

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C.3. Emissions Calculation Detail for Crusher House Cleanup Operations

> Emissions are calculated for particulate emissions associated with the cleanup process inside the crusher house. The cleanup operation consists of a vacuum pickup of crushed coal that has fallen off the crusher house conveyor, pneumatic transfer to a material recovery cyclone, and the return to the crusher house feed conveyor.

> The cleanup process is conducted periodically, but potential emissions are conservatively assumed based on continuous operation (i.e., 8,760 hr/yr).

C.3.1 Process Rates and Unit Conversions

Parameter	Value	Units	Basis
Annual Hours of Operation	8,760	hr/yr	Assuming continuous operation
Cyclone Outlet Grain Loading	0.014	gr/dscf	Conservative assumptions for minimum material collection efficiency. TCEQ guidance on material handling provides that BACT would be an outlet grain loading of less than 0.01 gr/scf or efficiency of 99%. Per EPA's Air Pollution Control Technology Fact Sheet, conventional cyclones typically achieve a minimum control efficiency of 70%. Assuming the outlet grain loading scales linearly with control efficiency, the outlet grain loading for a 70% control efficiency would be approximately 1.414 times higher than a 99% efficiency, or 0.01 gr/dscf x 1.414 = 0.01414 gr/dscf. https://www.tceq.texas.gov/permitting/air/nav/air_bact_mechsource.html
Unit Conversions	7,000	gr/lb	--
	60	min/hr	--

C.3.2 Potential Particulate Matter Emissions

> Emissions associated with the pneumatic transfer of crushed coal through crush house recycle system.

> The recycle cyclone is inherent process equipment; therefore, emissions calculated are uncontrolled.

> It is assumed that emissions of PM=PM10=PM2.5. This provides a conservative estimate for PM and PM10, as the outlet grain loading estimate would be appropriate for the finest classifications of particulate while larger diameter particulate would be controlled at a higher efficiency.

Parameter	Value	Units	Basis
Crusher House Cleanup Operations Cyclone Blower Rating	1,413	scfm	Maximum design rating for Roots Rotary Lobe Blower – Model 711 URAI R
Hourly Particulate Emissions	0.17	lb/hr	= 0.014 gr/dscf Cyclone Outlet Grain Loading x 1,413 scfm Crusher House Cleanup Operations Cyclone Blower Rating x 60 min/hr / 7000 gr/lb
Annual Particulate Emissions	0.75	ton/yr	= 0.17 lb/hr Hourly Particulate Emissions x 8760 hr/yr / 2000 lb/ton

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C.4. IA Storage Tank PTE Summary

> Relevant input data used to model potential emissions from the storage tanks permitted as IAs is included below.

Tank ID	Tank Description
IA-01	Station fuel-oil tanks (2 @ 1,100,000 gallons each) - T-1 & T-2 (South CT area)
IA-02	#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973 - T-10 525,000 (Fuel oil Storage & Unit 3 Light off Tank)
IA-03	Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each) - T-17 & T-18 (Steam Plant/Unit 3 Clean/Dirty Turbine Oil)
IA-04	Unleaded gasoline storage tanks - T-25(Coal Yard/Tractor Garage Area)
IA-05	Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons) - R3, R6, R7
IA-06	Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons) - R8, R9, R10, R11
IA-08	Kerosene Tank (500 gallons) - T-26 (Coal Yard/Tractor Garage Area)
IA-13	Natural Gas Distillate tank (2,000 gallons) - T-9 (CT area)
IA-14	Diesel Fuel tanks for emergency generators (3 @ 391 gallons) - T3, T4, T5 (CT area/Emergency Generators)
IA-15	Diesel Fuel tank for emergency fire pump (300 gallons) - T-8 (CT area/emergency fire pump AST)
IA-17	Diesel Fuel tank for emergency generator (837 gallons) - T-14 (Steam Plant/Unit 3 Emergency Generator)
IA-18	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons) - T-20, T-21 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)
IA-19	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons) - T-22, T-23 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)
IA-20	Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons) - R4, R44
IA-21	Turbine oil reservoir for Unit 3 seal oil (150 gallons) - R14
IA-22	Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons) - R18, R19 (Unit 3, outside out of service ESP)
IA-24	Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons) - T27, T28, T29 (Tractor Garage Building Read Area)
IA-38	Diesel Fuel tanks for emergency generators (2 @ 900 gallons) - T-6, T-7 CT area/between CT7 & CT8(EU28 & EU25)
IA-39	Diesel Fuel Tanks (500, 2000, 3@ 550, 1100 gallons) - T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)
IA-40	Mobile Diesel Fuel Tank (251 gallons/square tank) - T-39 (Stored in CT Warehouse when not in use)
IA-44	**Unit 3 Propylene Glycol Tank (3,000 gal)**
IA-45	**Hydroelectric Building Lube Oil Tanks (T-31 and T-32)**

		Max Capacity per Tank		Height	Diameter	Throughput	Representative	Total VOC Emissions	
Tank ID	No. Tanks	(gal)	(ft^3)	(ft)	(ft)	(gal/yr)	TankESP Stock	(lb/yr)	(tpy)
IA-01	2	1,100,000	147,049	36.04	72.08	13,200,000	DIESEL	403.03	0.20
IA-02	1	525,000	70,182	28.16	56.33	6,300,000	DIESEL	192.46	0.10
IA-03	2	9,000	1,203	7.26	14.52	108,000	KERO	4.20	2.10E-03
IA-04	1	1,000	134	3.49	6.98	12,000	GAS_X	207.42	0.10
IA-05	3	6,500	869	6.52	13.03	78,000	KERO	3.03	1.52E-03
IA-06	5	4,000	535	5.54	11.08	48,000	KERO	1.86	9.32E-04
IA-08	1	500	67	2.77	5.54	6,000	KERO	0.21	1.07E-04
IA-13	1	2,000	267	4.40	8.80	24,000	GAS_X	395.06	0.20
IA-14	3	391	52	2.55	5.11	4,692	DIESEL	0.12	5.89E-05
IA-15	1	300	40	2.34	4.67	3,600	DIESEL	0.08	3.92E-05
IA-17	1	837	112	3.29	6.58	10,044	DIESEL	0.31	1.54E-04
IA-18	2	440	59	2.66	5.31	5,280	DIESEL	0.14	7.04E-05
IA-19	2	550	74	2.86	5.72	6,600	DIESEL	0.19	9.59E-05
IA-20	2	1,000	134	3.49	6.98	12,000	KERO	0.47	2.33E-04
IA-21	1	150	20	1.85	3.71	1,800	KERO	0.06	2.98E-05
IA-22	2	400	53	2.57	5.14	4,800	KERO	0.15	7.72E-05
IA-24	4	560	75	2.88	5.76	6,720	KERO	0.25	1.25E-04
IA-38	2	900	120	3.37	6.74	10,800	DIESEL	0.33	1.65E-04
IA-39	6	2,000	267	4.40	8.80	24,000	DIESEL	0.73	3.67E-04
IA-40	1	251	34	2.20	4.40	3,012	DIESEL	0.06	2.89E-05
IA-44	1	3,000	401	5.04	10.07	36,000	PG	0.09	4.44E-05
IA-45	2	100	13	1.62	3.24	1,200	KERO	0.05	2.30E-05

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APPENDIX D. SUGGESTED REVISIONS TO PERMIT

To assist the Division in reviewing the application and to promote efficiency in the Division's efforts at preparing a revised Title V permit, sample suggested edits to Brown Generating Station's existing Title V permit (V-17-030 R1) that reflect the updates described in Section 5 are provided in this appendix.

KDAQ has issued a pre-draft of a revised permit coinciding with the Significant Permit Revision application submitted in December 2022. Various excerpts from this pre-draft permit are used to represent the requested updates to the Title V permit in lieu of utilizing V-17-030 R1. For example, the pre-draft has moved Unit 3 and its associated regulatory requirements to Section H of the operating permit. Excerpts related to the general permit updates requested (as described by Section 5.3.3.) are pulled from Section H of this pre-draft permit rather than Section B of V-17-030 R1.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 23-29 Combustion Turbines

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel	Control Equipment
23	Combustion Turbine (Unit 9), Model ABB GT 11N2	11/28/1995	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
24	Combustion Turbine (Unit 10) Model ABB GT 11N2	12/22/1995	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
25	Combustion Turbine (Unit 8) Model ABB GT 11N2	3/1/1996	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
26	Combustion Turbine (Unit 11) Model ABB GT 11N2	5/8/1996	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
27	Combustion Turbine (Unit 6), Model ABB GT 24	8/11/1999	1,678 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection when burning oil and low NO_X burners when burning natural gas
28	Combustion Turbine (Unit 7) Model ABB GT 24	8/8/1999	1,678 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection when burning oil and low NO_X burners when burning natural gas
29	Combustion Turbine (Unit 5) Model ABB GT 11N2	6/8/2001	1,368 MMBtu/hr	Natural Gas	Water injection

*A notification per **1. Operating Limitations d.** shall be submitted prior to the usage of distillate fuel oil as a secondary fuel for non-emergency usage.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of Significant Deterioration of Air Quality*;
401 KAR 52:060, *Acid rain permits,* incorporating the Federal Acid Rain provisions as codified in **40 CFR Parts 72 to 78** (see Section J).
401 KAR 60:005, Section 2(2)(pp), implementing **40 CFR 60, Subpart GG**, *Standards of Performance for Stationary Gas Turbines*;
401 KAR 63:002, Section 2(4)(dddd), implementing **40 CFR 63, Subpart YYYY**, *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*. This regulation applies, but these are existing units [40 CFR 63.6090(a)(1)] and they do not have to meet the requirements of this regulation [40 CFR 63.6090(b)(4)].
401 KAR 51:240, *CSAPR NO_x Annual Trading Program*
401 KAR 51:260, *CSAPR SO_2 Group 1 Trading Program*
40 CFR 97, Subpart ~~GGGGG~~EEEEE, *CSAPR NO_x Ozone Season Group ~~3~~ 2 Trading Program*
40 CFR 75, Appendix E, *Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units*

Commented [WJ2]: KDAQ - See comments in Section L regarding non-applicability of GGGGG with stay of SIP disapproval and implementation of the Interim Final Rule.

1. **Operating Limitations:**
   a. The operating rate for each unit shall not exceed the hourly maximum continuous rating listed above, at ISO standard conditions [401 KAR 51:017].

      Compliance Demonstration:
      To demonstrate compliance with this limit the operating rate shall be calculated from each average hourly fuel usage rate at ISO standard conditions, and corresponding fuel heating value characteristics of the fuel combusted.

   b. The maximum operating hours for each unit shall not exceed 2,500 hours per year based on a 12-month rolling total [401 KAR 51:017].

      Compliance Demonstration:
      To demonstrate compliance with this limit, the 12-month total for each unit shall be calculated monthly and reported semi-annually. The permittee shall maintain onsite a log of each 12-month rolling total.

   c. The permittee shall only operate a combustion turbine on emergency distillate fuel oil if there is an emergency and the primary fuel, natural gas, is unavailable, unless, a notification per **1. Operating Limitations: d.** is submitted [40 CFR 75, Appendix E, Section 2.1.4.3].

   d. Except for reliability tests (non-generation usage) and maintenance activities of the combustion turbines on distillate fuel oil, the permittee shall submit a notification to the Cabinet 60-days prior to switching to distillate fuel oil as a secondary fuel rather than an emergency fuel. All noted emission limits, recordkeeping and reporting requirements while operating on non-emergency distillate fuel oil will apply. Performance tests shall be completed prior to non-emergency usage of the CTs while operating on distillate fuel oil (secondary fuel) [401 KAR 52:020, Section 10].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:

a. Nitrogen oxide emissions from each unit shall not exceed the following values, at 15 percent oxygen on a dry basis:

Emission Unit	Plant Unit ID	NO_X emission limit when burning	
		Natural gas (ppm by volume)	Distillate fuel oil (ppm by volume)
23	9	42	65
24	10	42	65
25	8	42	65
26	11	42	65
27	6	25	42
28	7	25	42
29	5	25	N/A

[401 KAR 51:017 and 40 CFR 60.332(a)]

Compliance Demonstration:

For each unit, the permittee shall demonstrate compliance with this requirement during performance testing by using the emission estimate method in 40 CFR 75, Appendix E. Emission rates determined on a pound per million Btu basis shall be converted to parts per million (ppm) using Formula F-5 in 40 CFR 75, Appendix F. These procedures shall be used to identify the acceptable parametric values/ranges against which the data recorded by the continuous monitoring system required by **4. Specific Monitoring Requirements (a)** is compared. Continuous compliance with this requirement is demonstrated via compliance with **4. Specific Monitoring Requirements (a)** and **5. Specific Recordkeeping Requirements (a).**

Commented [AA3]: KDAQ - please refer to Section 5.3.2. of the permit renewal application for a discussion of these requested revisions.

b. These units are exempt from the emission limits in **2. Emission Limitations (a)** when ice fog is deemed a traffic hazard by the permittee [40 CFR 60.332(f)].

Compliance Demonstration:

During the semi-annual reporting required by **Section F – Monitoring, Recordkeeping, and Reporting Requirements**, the permittee shall submit to the Division the date, time, duration and weather conditions that created the hazard.

c. Exemptions from the requirements of **2. Emission Limitations(a)** shall be granted on a case-by-case basis, as determined by the Division, in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions shall be allowed only while the mandatory water restrictions are in effect [40 CFR 60.332(i)].

Compliance Demonstration:

During the semi-annual reporting required by **Section F – Monitoring, Recordkeeping, and Reporting Requirements**, the permittee shall submit to the Division the date, time, duration and proof of mandatory water restrictions that led to the exemption.

d. The sulfur content of fuel burned and sulfur dioxide emissions shall not exceed the following limits [401 KAR 51:017 and 40 CFR 60.333(b)]:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 39 **Existing 4SLB SI Emergency RICE**

Description:

Make/Model:	WINCO/ B35CS-17R1D (Dix Dam Crest Gate Emergency Generator)
Construction Commenced:	1970
Maximum Continuous Rating:	40 HP
Fuel:	Gasoline
Controls:	None

APPLICABLE REGULATIONS:

401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*.

1. **Operating Limitations:**
   a. The permittee shall:
      i. Change oil and filter every 500 hours of operation or annually, whichever comes first, or according to an oil analysis program [40 CFR 63:6602 referencing Item 6.a. of Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(j)];

      ii. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary [40 CFR 63.6602 referencing Item 6.b. of Table 2c to Subpart ZZZZ of Part 63];

      iii. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary and [40 CFR 63.6602 referencing Item 6.c. of Table 2c to Subpart ZZZZ of Part 63];

      iv. 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-start emission limitations apply [40 CFR 63:6602 referencing Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(h)].

   b. The permittee shall operate and maintain the stationary RICE according to the manufacturer's emission-related operating and maintenance instructions, or develop and follow the permittee's 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 [40 CFR 63.6625(e) and 40 CFR 63.6640(a) referencing Item 9. of Table 6 to Subpart ZZZZ of Part 63].

Business Use

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c. The permittee shall operate the emergency stationary RICE according to the requirements in 40 CFR 63.6640(f)(1) through (3). In order for the engine to be considered an emergency stationary RICE under 40 CFR 63, Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 63.6640(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 63.6640(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 63, Subpart ZZZZ and shall meet all requirements for non-emergency engines [40 CFR 63.6640(f)].

i. There is no time limit on the use of emergency stationary RICE in emergency situations [40 CFR 63.6640(f)(1)].

ii. The permittee may operate the emergency stationary RICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 63.6640(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 63.6640(f)(2) [40 CFR 63.6640(f)(2) and (f)(2)(i)].

iii. 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 ~~and emergency demand response~~ provided in 40 CFR 63.6640(f)(2). 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 [40 CFR 63.6640(f)(3)].

Commented [AA4]: KDAQ - please remove as 40 CFR 63.6640(f)(2)(ii) has been struck out.

d. The permittee shall be in compliance with the emission limitations and operating limitations that apply in 40 CFR 63, Subpart ZZZZ at all times [40 CFR 63.6605(a)].

e. At all times the permittee shall operate and maintain the emission unit, 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 any further efforts to reduce emissions if levels required by 40 CFR 63, Subpart ZZZZ 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 [40 CFR 63.6605(b)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 40-44 **Existing CI Emergency RICE <500 HP**

Emission Unit	Description	Manufacture Date	Maximum Continuous Rating (HP)	Fuel	Control Equipment
40	Cummins, Model 3304 (Brown Station Emergency Generator)	2000	135	Diesel	None
41	Caterpillar, Model 3306 (CT5 Emergency Generator)	2000	308		
42	Perkins Engine, Model DP150P3 (CT6 Emergency Generator)	1999	230		
43	Perkins Engine, Model DP150P3 (CT7 Emergency Generator)	1999	230		
44	Cummins, Model 681A5.9-F-1 (CT Area Fire Pump Engine)	1994	208		

APPLICABLE REGULATIONS:
401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**
   a. The permittee shall:
      i. Change oil and filter every 500 hours of operation or annually, whichever comes first, or according to an oil analysis program [40 CFR 63.6602 referencing Item 1.a. of Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(i)];

      ii. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first and replace as necessary [40 CFR 63.6602 referencing Item 1.b. of Table 2c to Subpart ZZZZ of Part 63];

      iii. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary and [40 CFR 63.6602 referencing Item 1.c. of Table 2 to Subpart ZZZZ of Part 63];

      iv. Minimize the engine's time spent at idle 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 non-startup emission limitations apply [40 CFR 63.6602 referencing Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(h)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. The permittee shall operate and maintain the stationary RICE according to the manufacturer's emission-related operating and maintenance instructions or the facility's developed 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 [40 CFR 63.6625(e) and 63.6640(a) referencing Item 9. of Table 6 to Subpart ZZZZ of Part 63].

c. The permittee shall operate the emergency stationary RICE according to the requirements in 40 CFR 63.6640(f)(1) through (3). In order for the engine to be considered an emergency stationary RICE under 40 CFR 63, Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 63.6640(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 63.6640(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 63, Subpart ZZZZ and shall meet all requirements for non-emergency engines [40 CFR 63.6640(f)].

i. There is no time limit on the use of emergency stationary RICE in emergency situations [40 CFR 63.6640(f)(1)].

ii. The permittee may operate the emergency stationary RICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 63.6640(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 63.6640(f)(2) [40 CFR 63.6640(f)(2) and (f)(2)(i)].

iii. 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 ~~and emergency demand response~~ provided in 40 CFR 63.6640(f)(2). 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 [40 CFR 63.6640(f)(3)].

Commented [AA5]: KDAQ - please remove as 40 CFR 63.6640(f)(2)(ii) has been struck out.

d. The permittee shall be in compliance with the emission limitations and operating limitations that apply in 40 CFR 63, Subpart ZZZZ at all times [40 CFR 63.6605(a)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 45-~~46~~ 48 & 63 New CI Emergency Fire Pump RICE

Emission Unit	Description	Model Year	Maximum Continuous Rating (HP)	Fuel	Control Equipment
45	John Deere, Model 6081HF001, 8.1 L displacement per cylinder (Steam Plant Emergency Fire Pump Engine #1)	April 2007	375	Diesel	None
46	John Deere, Model 6081HF001, 8.1 L displacement per cylinder (Steam Plant Emergency Fire Pump Engine #2)				
47	John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement; equipped with Clarke Fire Pump Engine – Model JX6H-UF50 (FGD Emergency Quench Water/Fire Pump Engine #1)	2007	485 (362 kW)	Diesel	None
48	John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement; equipped with Clarke Fire Pump Engine – Model JX6H-UF50 (FGD Emergency Quench Water/Fire Pump Engine #2)				
63	NGCC Emergency Fire Pump Engine	Projected March 2025	400		

Commented [AA7]: KDAQ - please move EU47 and EU48 here per April 2022 Section 502(b)(10) change notification.

Commented [AA8]: Approval deferred to 2030

APPLICABLE REGULATIONS:

401 KAR 60:005, Section 2(2)(lll), implementing **40 CFR 60, Subpart IIII**, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**
   a. The permittee shall meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII [40 CFR 63.6590(c)(7)].

   b. The permittee shall use diesel fuel certified to the standards in 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 [40 CFR 60.4207(b)].

   Compliance Demonstration:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

The permittee shall demonstrate compliance by using fuel supplier certification.

c. The permittee shall operate the emergency stationary ICE according to the requirements in 40 CFR 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing, ~~emergency demand response~~, and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and shall meet all requirements for non-emergency engines [40 CFR 60.4211(f)].

i. There is no time limit on the use of emergency stationary ICE in emergency situations [40 CFR 60.4211(f)(1)].

ii. The permittee may operate the emergency stationary ICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 60.4211(f)(2) [40 CFR 60.4211(f)(2) and (f)(2)(i)].

iii. 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 and emergency demand response provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), 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. The 50 hours per year for nonemergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met [40 CFR 60.4211(f)(3) and (f)(3)(i)]:

1. The engine is dispatched by the local balancing authority or local transmission and distribution system operator [40 CFR 60.4211(f)(3)(i)(A)];

2. 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 [40 CFR 60.4211(f)(3)(i)(B)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines [40 CFR 60.4211(f)(3)(i)(C)].

4. The power is provided only to the facility itself or to support the local transmission and distribution system [40 CFR 60.4211(f)(3)(i)(D)].

5. The permittee 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 permittee [40 CFR 60.4211(f)(3)(i)(E)].

2. Emission Limitations:

The permittee shall comply with the following emission standards for EU 45 and 46:

Pollutant	Emission Standard
NMHC + NO_X	7.8 g/HP-hr
CO	2.6 g/HP-hr
PM	0.40 g/HP-hr

[40 CFR 60.4205(c)]

The permittee shall comply with the following emission standards for EU 63:

Pollutant	Emission Standard
NMHC + NO_X	3.0 g/HP-hr
CO	2.6 g/HP-hr
PM	0.15 g/HP-hr

[40 CFR 60.4205(c)]

Compliance Demonstration:

a. The permittee shall demonstrate compliance with the emission standards by purchasing an engine certified to the emission standards listed above. The engine shall be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). In the absence of certification from the manufacturer, the permittee shall maintain records of performances tests conducted on the engines, or similar engines, which demonstrate the engines meet the emission standards and that the testing was conducted according to **3. Testing Requirements** [40 CFR 60.4211(c) and 401 KAR 52:020, Section 10].

b. The permittee shall operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer, over the entire life of the engine. In addition, the permittee shall only change those settings that are permitted by the manufacturer. The permittee shall also meet the requirements of 40 CFR Part~~s 89, 94, and/or~~ 1068, as they apply [40 CFR 60.4211(a) and 40 CFR 60.4206].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units ~~47~~ 49, 51-52 & 60 New Emergency CI RICE

Emission Unit	Description	Model Year	Maximum Continuous Rating	Fuel	Control Equipment
~~47~~	~~John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement (Emergency Quench Water Pump Engine #1) –Tier 2 engine~~	~~April 2007~~	~~485 HP (362 kW)~~		
~~48~~	~~John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement (Emergency Quench Water Pump Engine #2) –Tier 2 engine~~	~~April 2007~~	~~485 HP (362 kW)~~	Diesel	None
49	Generac Make: Doosan; Model: 390; 10 cylinder, 18.3 L total displacement –Tier 2, emergency engine	2010	752 HP (561 kW)		
51 & 52	2 Cummins QSK23-G7 NR2, Tier 2 certified emergency engines	2014	1220 HP each		
60	NGCC Plant Tier 2 certified emergency engine	Projected March 2025	~~2,682 HP~~ (2 MW)		

Commented [MZ9]: KU - Post comment => 47 and 48 should be moved to new fire pump section per 502(b)10 Change.

Commented [MZ11]: KDAQ - Can we just describe this as a **2 MW** unit instead of HP or BHP because those details may change? If not, please change to a **2,925 BHP** engine. Please understand, this will not change the emissions because this size of engine is more efficient resulting in diesel consumption rate of 133 gal/hr, whereas, the emissions and forms were based on 137 gal/hr.

Commented [AA10]: Approval deferred to 2030

APPLICABLE REGULATIONS:

401 KAR 60:005, Section 2(2)(lll), implementing **40 CFR 60, Subpart IIII**, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**

   a. ~~For Emission Units 47 and 48, the permittee shall meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII [40 CFR 63.6590(c)(7)].~~

   Commented [MZ12]: KU Post Comment - Should be deleted.

   b. For Emission Units 49, 51, 52 and 60 the permittee does not have to meet the requirements of 40 CFR 63, Subpart ZZZZ and 40 CFR 63, Subpart A except for the initial notification requirements of 40 CFR 63.6645(f) [40 CFR 63.6590(b)(i)].

   c. The permittee shall use diesel fuel certified to the standards in 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 [40 CFR 60.4207(b)].

   Compliance Demonstration:
   The permittee shall demonstrate compliance by using fuel supplier certification.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

d. The permittee shall operate the emergency stationary ICE according to the requirements in 40 CFR 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing, ~~emergency demand response,~~ and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and shall meet all requirements for non-emergency engines [40 CFR 60.4211(f)].

i. There is no time limit on the use of emergency stationary ICE in emergency situations [40 CFR 60.4211(f)(1)].

ii. The permittee may operate the emergency stationary ICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 60.4211(f)(2) [40 CFR 60.4211(f)(2) and (f)(2)(i)].

iii. 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 and emergency demand response provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), 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. The 50 hours per year for nonemergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met [40 CFR 60.4211(f)(3) and (f)(3)(i)]:

1. The engine is dispatched by the local balancing authority or local transmission and distribution system operator [40 CFR 60.4211(f)(3)(i)(A)];

2. 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 [40 CFR 60.4211(f)(3)(i)(B)].

3. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines [40 CFR 60.4211(f)(3)(i)(C)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. The power is provided only to the facility itself or to support the local transmission and distribution system [40 CFR 60.4211(f)(3)(i)(D)].

5. The permittee 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 permittee [40 CFR 60.4211(f)(3)(i)(E)].

2. Emission Limitations:

The permittee shall, for all units, comply with the emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 1039, Appendix I for all pollutants, and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007 [40 CFR 60.4205(b) referencing 40 CFR 60.4202(a)(2)].

Compliance Demonstration:

a. The permittee shall demonstrate compliance with the emission standards by purchasing an engine certified to the emission standards listed above. The engine shall be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). In the absence of certification from the manufacturer, the permittee shall maintain records of performances tests conducted on the engines, or similar engines, which demonstrate the engines meet the emission standards and that the testing was conducted according to **3. Testing Requirements** [40 CFR 60.4211(c) and 401 KAR 52:020, Section 10].

b. The permittee shall operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer, over the entire life of the engine. In addition, the permittee shall only change those settings that are permitted by the manufacturer. The permittee shall also meet the requirements of 40 CFR Part~~s 89, 94, and/or~~ 1068, as they apply [40 CFR 60.4211(a) and 40 CFR 60.4206].

3. Testing Requirements:

a. Testing shall conform to the requirements of 40 CFR 60.4212(a) through (d), as appropriate [40 CFR 60.4212].

b. Testing shall be conducted at such times as may be requested by the cabinet in accordance with 401 KAR 50:045, Section 4.

4. Specific Monitoring Requirements:

a. The permittee shall install a non-resettable hour meter prior to startup of the engine [40 CFR 60.4209(a)].

b. The permittee shall monitor hours of operation and fuel usage (Mgal) on a monthly basis [401 KAR 52:020, Section 10].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 55-57 Natural Gas Process Heaters

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel
55 (CT NG – 05)	NG Preheater NATCO S832-205D	2003	2.4 MMBtu/hr	Natural Gas
56 (CT NG – 06)	NG Preheater ETI Custom Built	2000	7.0 MMBtu/hr	
57 (CT NG – 07)	NG Preheater ETI Custom Built	2000	7.0 MMBtu/hr	

APPLICABLE REGULATIONS:
401 KAR 59:015, *New indirect heat exchangers*

401 KAR 63:002, Section (2)(4)(iiii), 40 C.F.R. 63.7480 to 63.7575, Tables 1 to 13 (**Subpart DDDDD**), *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*

1. **Operating Limitations:**
   a. For Emission Unit 55, the permittee shall complete a tune-up every 5 years as specified in 40 CFR 63.7540 [40 CFR 63.7500(a)(1) referencing Item 1. of 40 CFR 63, Subpart DDDDD, Table 3; 40 CFR 63.7500(e)].

   b. For Emission Units 56 and 57, the permittee shall complete a tune-up every 2 years as specified in 40 CFR 63.7540 [40 CFR 63.7500(a)(1) referencing Item 2. of 40 CFR 63, Subpart DDDDD, Table 3; 40 CFR 63.7500(e)].

   c. These units shall have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in 40 CFR 63, Subpart DDDDD, Table 3, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISI 50001 for at least one year between January 1, 2008 and the compliance date specified in 40 CFR 63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment shall include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in 40 CFR 63.7575 [40 CFR 63.7500(a)(1) referencing Item 4. of 40 CFR 63, Subpart DDDDD, Table 3]:
      i. A visual inspection of the boiler or process heater system [40 CFR 63.7500(a)(1) referencing Item 4.a. of 40 CFR 63, Subpart DDDDD, Table 3].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

ii. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints [40 CFR 63.7500(a)(1) referencing Item 4.b. of 40 CFR 63, Subpart DDDDD, Table 3].

iii. An inventory of major energy use systems consuming energy from the affected boilers and process heaters and which are under the control of the permittee [40 CFR 63.7500(a)(1) referencing Item 4.c. of 40 CFR 63, Subpart DDDDD, Table 3].

iv. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified [40 CFR 63.7500(a)(1) referencing Item 4.d. of 40 CFR 63, Subpart DDDDD, Table 3].

v. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified [40 CFR 63.7500(a)(1) referencing Item 4.e. of 40 CFR 63, Subpart DDDDD, Table 3].

vi. A list of cost-effective energy conservation measures that are within the facility's control [40 CFR 63.7500(a)(1) referencing Item 4.f. of 40 CFR 63, Subpart DDDDD, Table 3].

vii. A list of the energy savings potential of the energy conservation measures identified [40 CFR 63.7500(a)(1) referencing Item 4.g. of 40 CFR 63, Subpart DDDDD, Table 3].

viii. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments [40 CFR 63.7500(a)(1) referencing Item 4.h. of 40 CFR 63, Subpart DDDDD, Table 3].

d. At all times, the permittee shall 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. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that 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 [40 CFR 63.7500(a)(3)].

e. These units are not subject to the emission limits in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 13, or the operating limits in 40 CFR 63, Subpart DDDDD Table 4 [40 CFR 63.7500(e)].

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SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. Although these activities are designated as insignificant the permittee must comply with the applicable regulation. Process and emission control equipment at each insignificant activity subject to an opacity standard shall be inspected monthly and a qualitative visible emissions evaluation made. Results of the inspection, evaluation, and any corrective action shall be recorded in a log.

	Description	Generally Applicable Regulation
1.	Station fuel-oil tanks (2 @ 1,100,000 gallons each)	None
2.	#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973	None
3.	Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each)	None
4.	Unleaded gasoline storage tanks	None
5.	Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons)	None
6.	Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons)	None
7.	Burning of Off-Specification Used Oil for Energy Recovery	401 KAR 61:020
8.	Kerosene Tank (500 gallons)	None
9.	Distillate Oil and/or Propane Coal Belt Heaters	None
10.	Limestone Storage Pile	401 KAR 63:010
11.	Limestone Reclaim Maintenance Tunnel Exhaust Vent	401 KAR 59:010
12.	Sorbent Storage Silos (for SO_3 mitigation)	401 KAR 59:010
13.	Natural Gas Distillate tank (2,000 gallons)	None
14.	Diesel Fuel tanks for emergency generators (3 @ 391 gallons)	None
15.	Diesel Fuel tank for emergency fire pump (300 gallons)	None
16.	Liquid Hg Control Additives	None
17.	Diesel Fuel tank for emergency generator (837 gallons)	None
18.	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons)	None
19.	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons)	None
20.	Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons)	None
21.	Turbine oil reservoir for Unit 3 seal oil (150 gallons)	None
22.	Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons)	None
23.	Lab Fume Hood	None
24.	Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons)	None
25.	PAC Storage Silos	401 KAR 59:010
26.	Bottom Ash Transport	401 KAR 63:010
27.	Fly Ash Transport	401 KAR 63:010
28.	Gypsum Transport & Process Water System Solids	401 KAR 63:010
29.	Landfill Truck Loading and Unloading & Process Water System Solids	401 KAR 63:010
30.	Active Area of the CCR Landfill (Wind Erosion) & Process Water System Solids	401 KAR 63:010
31.	Slipstream Carbon Dioxide (CO_2) capture System – Research	401 KAR 63:010

Business Use

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SECTION C - INSIGNIFICANT ACTIVITIES (CONTINUED)

32. Bottom Ash Handling including storage pile (associated with CCR landfill operations)	401 KAR 63:010
33. Fly Ash Handling including load out to trucks (associated with CCR landfill operations)	401 KAR 63:010
34. Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)	401 KAR 63:010
35. Fly Ash Storage Silos (2) (associated with CCR landfill operations)	401 KAR 63:010, 401 KAR 59:010
36. Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)	401 KAR 63:010
37. NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)	None
38. Diesel Fuel Tanks for emergency generators (2 @ 900 gallons)	None
39. Diesel Fuel Tanks (500, 2000, 3@ 550, 1,100 gallons) T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)	None
40. Mobile Diesel Fuel Tank (251 gallons/square tank) T-39 (Stored in CT Warehouse when not in use)	None
41. Lube Oil System with Demister Vents	None
42. Inherent Diesel Storage Tanks for NGCC Units (1 @ 4,000 gallons for 2 MW Emergency Generator; 1 @ 440 gallons for Emergency Fire Pump Engine)	401 KAR 52:020
43. HVAC Heaters (Total Heat Input < 10 MMBtu/hr)	None
44. Unit 3 Propylene Glycol Tank (3,000 gal)	None
45. Hydroelectric Building Lube Oil Tanks (T-31 and T-32)	None
46. CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)	None
47. Unit 3 Hydrazine Monohydrate Tote (180 gal)	None
48. Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)	401 KAR 59:010

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SECTION H - ALTERNATE OPERATING SCENARIOS

Emission Unit 3 **Indirect Heat Exchanger**

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel	Controls
3	Pulverized coal- dry bottom-tangentially-fired indirect heat exchanger	July 19, 1971	5,300 MMBtu/hr	Coal, No. 2 Fuel Oil for startup and stabilization	Pulse Jet Fabric Filter (installed 2015) Low NO_X burners (installed 1992) Wet FGD (installed 2010), SCR (installed 2012) Dry sorbent injection for sulfuric acid mist control (installed 2013) Dry sorbent injection system using powdered activated carbon (installed 2015) Liquid additives for mercury control (installed 2015)

APPLICABLE REGULATIONS:

401 KAR 51:160, *NO_X requirements for large utility and industrial boilers*
401 KAR 51:210, *CAIR NO_X annual trading program* (See Section K~~1~~)
401 KAR 51:220, *CAIR NO_X ozone season trading program* (See Section K)
401 KAR 51:230, *CAIR SO_2 trading program* (See Section K)
401 KAR 52:060, *Acid rain permits*, incorporating the Federal Acid Rain provisions as codified in **40 CFR Parts 72 to 78** (see Section J)
401 KAR 61:015, *Existing indirect heat exchangers*
401 KAR 63:002, Section 2(4)(yyyyy), implementing **40 CFR 63, Subpart UUUUU**, *National Emission Standards for Hazardous Air Pollutants, Coal- and Oil-Fired Electric Utility Steam Generating Units*
40 CFR Part 64, *Compliance Assurance Monitoring*
40 CFR 97, Subpart AAAAA, *CSAPR NO_X Annual Trading Program*
40 CFR 97, Subpart CCCCC, *CSAPR SO_2 Group 1 Trading Program*
40 CFR 97, Subpart ~~GGGGG~~EEEEE, *CSAPR NO_X Ozone Season Group ~~3~~ 2 Trading Program*

Commented [MZ52]: KDAQ - In Trimble County's 2022 permit (V-22-028), Section K only says "CSPAR implementation is no in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule". No other words/requirements. Suggest the same for this permit.

Commented [WJ53]: KDAQ - See comments in Section L.

ADDITIONAL REQUIREMENTS:

Consent Decree filed on March 17, 2009 in U.S. District Court for the Eastern District of Kentucky, Central Division, Lexington, *United States of America v. Kentucky Utilities Company,* Civil Action No. 5:07-CV-0075-KSF ("Consent Decree").

1. **Operating Limitations:**
   a. The total heat input to the emission unit shall be no greater than 5,300 MMBtu/hr. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 92].

      Compliance Demonstration:
      To demonstrate compliance with this requirement the permittee shall calculate the hourly heat input rate using the hourly mass coal burned rate and weekly composite fuel sampling analysis data collected.

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

b. By no later than December 31, 2012, the permittee shall install an SCR for the emission unit [Consent Decree, Paragraph 5].

c. By no later than December 31, 2010, the permittee shall install an FGD on the emission unit [Consent Decree, Paragraph 19].

d. The permittee shall conduct periodic performance tune-ups of the EGUs, as specified in 40 CFR 63.10021(e)(1) through (9). For the first tune-up, the burner inspection may be performed any time prior to the tune-up or may be delayed until the next scheduled EGU outage provided the requirements of 40 CFR 63.10005 are met. Subsequently, the permittee shall perform an inspection of the burner at least once every 36 calendar months unless the EGU employs neural network combustion optimization during normal operations in which case the permittee shall perform an inspection of the burner and combustion controls at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the tune-up work practice requirements shall be performed within 30 days after the re-start of the affected unit [40 CFR 63.9991(a)(1) referencing Item 1. Of Table 3 to Subpart UUUUU of Part 63, 40 CFR 63.10006(i), and 40 CFR 63.10021(e)].

   i. As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows [40 CFR 63.10021(e)(1)]:

      1. Burner or combustion control component parts needing replacement that affect the ability to optimize NO_x and CO shall be installed within 3 calendar months after the burner inspection [40 CFR 63.10021(e)(1)(i)].

      2. Burner or combustion control component parts that do not affect the ability to optimize NO_x and CO may be installed on a schedule determined by the operator [40 CFR 63.10021(e)(1)(ii)].

   ii. As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type [40 CFR 63.10021(e)(2)].

   iii. As applicable, observe the damper operations as a function of mill and/or cyclone loading, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors [40 CFR 63.10021(e)(3)].

   iv. As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors [40 CFR 63.10021(e)(4)].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

v. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary [40 CFR 63.10021(e)(5)].

vi. Optimize combustion to minimize generation of CO and NO_x. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_x optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles [40 CFR 63.10021(e)(6)].

vii. While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_x in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). The permittee may use portable CO, NO_x, and O_2 monitors for this measurement. EGUs employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system [40 CFR 63.10021(e)(7)].

viii. Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in 40 CFR 63.10021(e)(1) through (e)(9) including [40 CFR 63.10021(e)(8)]:

1. The concentrations of CO and NO_x in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems [40 CFR 63.10021(e)(8)(i)].

2. A description of any corrective actions taken as a part of the combustion adjustment [40 CFR 63.10021(e)(8)(ii)].

3. The type(s) and amount(s) or fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period [40 CFR 63.10021(e)(8)(iii)].

ix. ~~The permittee shall report each instance in which an applicable emissions limit or operating limit in 40 CFR 63, Subpart UUUUU, Tables 1 through 4 were not met or the permittee failed to conduct a required tune-up. These instances are deviations from the requirements of 40 CFR 63, Subpart UUUUU. These deviations shall be reported according to 40 CFR 63.10031.~~ Prior to January 1, 2024, report the tune-up date electronically, in a PDF file, in your semiannual compliance report, as specified in 40

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

CFR 63.10031(f)(4) and (6) and, if requested by the Administrator, in hard copy, as specified in 40 CFR 63.10031(f)(5). On and after January 1, 2024, report the tune-up date electronically in your quarterly compliance report, in accordance with 40 CFR 63.10031(g) and section 10.2 of appendix E to this subpart. The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed. [40 CFR 63.10021(e)(9)].

Commented [MZ54]: KDAQ - See 85 FR 55759, Sept. 9, 2020]

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements(l) and (m)** and **6. Specific Reporting Requirements(e)(i)(4)**.

e. The permittee shall be in compliance with the emission limits and operating limits in 40 CFR 63, Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, the permittee shall meet the work practice requirements, items 3 and 4, in Table 3 to 40 CFR 63, Subpart UUUUU during periods of startup or shutdown [40 CFR 63.10000(a)].

f. During startup:
   i. The permittee has the option of complying using either of the following work practice standards:
      1. If complying using paragraph (1) of the definition of "startup" in 40 CFR 63.10042, the permittee shall operate all continuous monitoring systems (CMS) during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends with any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the permittee shall use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the unit converts to firing coal, residual oil, or solid oil-derived fuel, the permittee shall engage all of the applicable control technologies except dry scrubber and SCR. The permittee shall start dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee shall comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR 63, Subpart UUUUU. The permittee shall keep records during startup periods. The permittee shall provide reports concerning activities and startup periods, as specified in 40 CFR 63.10011(g) and 63.10021(h) and (i). If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i).

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

2. If complying using paragraph (2) of the definition of "startup" in 40 CFR 63.10042, the permittee shall operate all CMS during startup. The permittee shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the permittee shall use one or a combination of the clean fuels defined in 40 CFR 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The permittee shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. The permittee shall meet the startup period work practice requirements as identified in 40 CFR 63.10020(e). Once the unit starts firing coal, residual oil, or solid oil-derived fuel, the permittee shall vent emissions to the main stack(s). The permittee shall comply with the applicable emission limits beginning with the hour after startup ends. The permittee shall engage and operate particulate matter control(s) within 1 hour of first firing coal, residual oil, or solid oil-derived fuel. The permittee shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than 40 CFR 63, Subpart UUUUU that require operation of the control devices.

ii. If the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, the permittee shall comply with the limit at all times; otherwise, the permittee shall comply with the applicable emission limit at all times except for startup and shutdown periods.

iii. The permittee shall collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (e). The permittee shall keep records during startup periods, as provided in 40 CFR ~~63.10031 and~~ 63.10021(h) and 63.10032. The permittee shall provide reports concerning activities and startup periods, as specified in 40 CFR 63.10011(g), 63.10021(i), and 63.10031. If you elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, you must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) [40 CFR 63.9991(a)(1) referencing Item 3. of Table 3 to Subpart UUUUU of Part 63].

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements(l) and (m)** and **5. Specific Recordkeeping Requirements(n)**.

g. During shutdown: The permittee shall operate all CMS during shutdown (as defined in 40 CFR 63.10042). The permittee shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

i. While firing coal, residual oil, or solid oil-derived fuel during shutdown, the permittee shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee shall operate controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than 40 CFR 63, Subpart UUUUU and that require operation of the control devices.

ii. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in 40 CFR 63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

iii. The permittee shall comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time the permittee shall meet this work practice. The permittee shall collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee shall keep records during shutdown periods, as provided in 40 CFR 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The permittee shall provide reports concerning activities and shutdown periods, as specified in 40 CFR 63.10011(g), 63.10021(i), and 63.10031 [40 CFR 63.9991(a)(1) referencing Item 4. of Table 3 to Subpart UUUUU of Part 63].

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements(l) and (m)** and **5. Specific Recordkeeping Requirements(n)**

h. At all times, operate and maintain the 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. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA 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. [40 CFR 63.10000(b)].

i. Following the construction, commissioning, and commencement of normal operation of EU58 (Unit 12 Combustion Turbine), the permittee shall cease operation of EU03 (Unit 3 Boiler). [To preclude 401 KAR 51:017]

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Compliance Demonstration:
Compliance shall be demonstrated according to **6. Specific Reporting Requirements (g)**.

2. Emission Limitations:

a. Emissions shall not exceed 40 percent opacity except:

i. A maximum of 60 percent opacity shall be permissible for not more than 1 six-minute period in any sixty 60 consecutive minutes;

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

ii. For emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions, provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [401 KAR 61:015, Section 4(3)]

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use the performance tests required by **3. Testing Requirements(a)**.

b. Particulate matter (PM) emissions shall not exceed 0.128 lb/MMBtu based on a three-hour average [401 KAR 61:015, Section 4(1) and Section 4(4)].

Compliance Demonstration:
Compliance with the limit in **2. Emission Limitations(c)** shall constitute compliance with this limit.

c. The permittee shall continuously operate the PJFF for the emission unit to achieve a PM emission rate no greater than 0.030 lb/MMBtu. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 30A].

Compliance Demonstration:
Compliance with this requirement shall be demonstrated by an annual stack test in accordance with **3. Testing Requirements(b)**. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 30A].

d. Sulfur dioxide (SO_2) emissions from the emission unit shall not exceed 5.15 lb/MMBtu based on a 24-hour average [401 KAR 53:010 and 401 KAR 61:015, Section 5(1)].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a SO_2 CEMS. Compliance with the 5.15 lb/MMBtu limit, based on a 24-hour average, assures compliance with the SO_2 limit in 401 KAR 61:015.

e. Annually, on a calendar year basis, SO_2 emissions from the emission unit shall not exceed 2,300 tons per calendar year. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 22].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a SO_2 CEMS in accordance with the reference methods in 40 CFR Part 75. The permittee shall not use SO_2 allowances to comply with this limit [Consent Decree, Paragraph 24].

f. The permittee shall commence continuous operation of the FGD so as to achieve and thereafter maintain a **30-day Rolling Average Emission Rate** for SO_2 of no greater than 0.100 lb/MMBtu or a **30-day Rolling Average SO_2 Removal Efficiency** of not lower than 97%. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 20].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a SO_2 CEMS, in

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

accordance with the reference methods in 40 CFR Part 75, upstream and downstream of the wet flue gas desulfurization system. The permittee may not use SO_2 allowances to comply with this limit [Consent Decree, Paragraph 24].

g. Emissions of nitrogen oxides from the emission unit shall not exceed 0.070 lb/MMBtu based on a **30-day Rolling Average Emission Rate** except as otherwise provided herein. If the dispatch (including startup, shutdown, and/or load ramping) of the emission unit requires operation of the unit at a load level that results in flue gas temperature so low that it becomes technically infeasible to continuously operate the SCR, despite best efforts by the permittee to do so, the nitrogen oxide emission rate shall not exceed 0.080 lb/MMBtu on a **30-day Rolling Average Emission Rate** [Consent Decree, Paragraphs 6 and 7].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a NO_X CEMS in accordance with the reference methods in 40 CFR Part 75. The calculations to demonstrate compliance with the 0.070 lb/MMBtu NO_X limit does not include dispatch events (startup, shutdown, and/or load ramping). The calculations to demonstrate compliance with the 0.080 lb/MMBtu NO_X limit does include dispatch events. The permittee shall use SCR operational data, as required by **5. Specific Recordkeeping Requirements(f)**, to demonstrate the use of the thirty (30)-day rolling average 0.080 lb/MMBtu limit. The permittee shall not use NO_X allowances to comply with this limit.

h. Emissions of sulfuric acid mist (SAM) from Emission Unit 3 shall not exceed 473.1 tons per year based on a twelve (12)–month rolling total. This is a voluntary federally-enforceable limit to preclude 401 KAR 51:017.

Compliance Demonstration:
To demonstrate compliance with this limit the permittee shall determine monthly SAM emissions from Emission Unit 3 and add the total to the previous 11-month SAM emissions total. The permittee shall maintain a log onsite of the 12-month rolling total SAM emissions. Monthly SAM emissions shall be determined by:

i. SAM emissions from fuel oil during startup:

$$SAM_{Fuel\ Oil}\left(\frac{\text{tons}}{\text{month}}\right) = \frac{Fuel\ Oil\ Usage\left(\frac{10^3\ \text{gal}}{\text{month}}\right) \times EF\left(\frac{\text{lb}\ SO_3}{10^3\ \text{gal}}\right)}{2000\left(\frac{\text{lb}}{\text{ton}}\right)} \times 1.225\left(\frac{\text{lb}\ H_2SO_4}{\text{lb}\ SO_3}\right)$$

Where, EF = the most recent AP-42 emission factor, currently 5.7S lb/10^3 gallons, where S is the monthly average weight percent of sulfur in the fuel oil.

ii. SAM emissions from burning coal:

$$SAM_{FGD} = \frac{Heat\ Input_{FGD}\left(\frac{\text{MMBtu}}{\text{month}}\right) \times EF_{FGD}\left(\frac{\text{lb}\ SO_3}{\text{MMBtu}}\right)}{2000\left(\frac{\text{lb}}{\text{ton}}\right)} \times 1.225\left(\frac{\text{lb}\ H_2SO_4}{\text{lb}\ SO_3}\right)$$

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

Where, EF_{FGD} = the most recent SAM stack test emission factor in lb/MMBtu and $Heat\ Input_{FGD}$ is the total monthly heat input from Emission Units 3 while exiting through the FGD stack. The stack test emission factor will be established according to the testing required by **3. Testing Requirements(c)**.

i. Emissions from Emission Unit 3 shall not exceed the limitations in the table below [40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of Part 63]. If the permittee elects to comply with these emission limitations using emissions averaging, emissions averaging shall be conducted according to 40 CFR 63.10009 and 40 CFR 63.10022.

Pollutant	Emission Limit	Compliance Demonstration
PM	0.030 lb/MMBtu **OR** 0.30 lb/MWh	Quarterly stack testing **OR** PM CEMS. [Table 5., Item 1; and Table 7. also 40 CFR 63.10005.]
OR		
Total non-Hg HAP Metals	0.000050 lb/MMBtu **OR** 0.50 lb/GWh	Quarterly stack testing [Table 5., Item 2; and Table 7. also 40 CFR 63.10005.]
OR		
All of these: Antimony	0.80 lb/TBtu **OR** 0.0080 lb/GWh	Quarterly stack testing for each [Table 5., Item 2; and Table 7. also 40 CFR 63.10005.]
Arsenic	1.1 lb/TBtu **OR** 0.020 lb/GWh	
Beryllium	0.20 lb/TBtu **OR** 0.0020 lb/GWh	
Cadmium	0.30 lb/TBtu **OR** 0.0030 lb/GWh	
Chromium	2.8 lb/TBtu **OR** 0.030 lb/GWh	
Cobalt	0.80 lb/TBtu **OR** 0.0080 lb/GWh	
Lead	1.2 lb/TBtu **OR** 0.020 lb/GWh	
Manganese	4.0 lb/TBtu **OR** 0.050 lb/GWh	
Nickel	3.5 lb/TBtu	

Commented [MZ56]: KU - Table 5 has been revamped. eCFR :: 40 CFR Part 63 Subpart UUUUU -- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

Pollutant	Emission Limit	Compliance Demonstration
	OR 0.040 lb/GWh	
Selenium	5.0 lb/TBtu **OR** 0.060 lb/GWh	
AND		
HCl	0.0020 lb/MMBtu **OR** 0.020 lb/MWh	Quarterly stack testing **OR** HCl/HF CEMS. [Table 5., Item 3; and Table 7. also 40 CFR 63.10005.]
OR		
SO_2	0.20 lb/MMBtu **OR** 1.5 lb/MWh	SO_2 CEMS. [Table 5., Item 3; and Table 7.]
AND		
Hg	1.2 lb/TBtu, **OR** 0.013 lb/GWh	Hg CEMS. [Table 5., Item 4; and Table 7. also 40 CFR 63.10005.] **OR** Sorbent Trap Monitoring. [Table 5., Item 4; and Table 7. also 40 CFR 63.10005.]

3. Testing Requirements:

a. The permittee shall determine the opacity of emissions from the stack by U.S. EPA Reference Method 9 at least once every 14 operating days, or more frequently if requested by the Division or required by this permit [401 KAR 50:055].

b. The permittee shall conduct a stack test for PM on the stack servicing this unit at least once each calendar year, with each stack test conducted at least 6 months apart. The reference methods and procedures for determining compliance with the PM emission rates shall be those specified in 40 CFR 60, Appendix A, Method 5 (with or without the Method 5 adjustment specified in 40 CFR 63, Subpart UUUUU), 5B, or 17, or an alternative method requested by the permittee, and approved for use by EPA. Each test shall consist of three separate runs performed under representative operating conditions and not during periods of startup, shutdown, or malfunction. The sampling time for each run shall be at least 120 minutes and volume of each run shall be 1.70 dry standard cubic meters (sixty (60) dry standard cubic feet). The permittee shall calculate the PM emission rates from the stack test results in accordance with 40 CFR 60.8(f). This is a permanent federally-enforceable testing requirement [Consent Decree, Paragraph 32 and 401 KAR 50:055].

c. The permittee shall conduct annual performance tests (at least 180 days apart), operating under the conditions established for **4. Specific Monitoring Requirements(k)**, to determine the SAM emission factor [401 KAR 50:055].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

d. During the initial SAM performance testing the permittee established the control device's operating parameters that are used as an indicator of SAM emissions, according to **4. Specific Monitoring Requirements(k)**. There may be short-term exceedances during the testing period required to establish or reestablish the operating parameter indicator ranges. These exceedances will not be considered noncompliance periods since the testing is required to establish a permit requirement. The Test Protocol form required by Section G(5)(a) shall detail the method and monitoring to be used to establish the correlation between the control device operating parameters and SAM emissions. The test report shall detail the results of the correlation testing, including the operating parameter indicator ranges to be used [401 KAR 50:055 and 40 CFR 64.6(c)].

e. If the emission unit reports PM exceedances, or SAM excursions for 5% or more of its operating hours during any calendar quarter, then the permittee shall conduct performance testing for PM or SAM emissions, as applicable, during the following calendar quarter while operating under representative conditions. PM emissions shall be determined according to 40 CFR 60, Appendix A, Method 5 (with or without the Method 5 adjustment specified in 40 CFR 63, Subpart UUUUU), 5B, or 17, or an alternative method approved by EPA. The SAM emission factor shall be re-established according to the method in **3. Testing Requirements(d)**. This requirement may be waived if the permittee can demonstrate to the satisfaction of the Division that the cause of the exceedance has been identified and corrected [40 CFR 64.6].

f. For EGUs using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under 40 CFR 63.10000(c), the permittee shall conduct all applicable performance tests according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007 at least every year [40 CFR 63.10006(a)].

g. For affected units meeting the LEE requirements of 40 CFR 63.10005(h), the permittee shall repeat the performance test once every 3 years (once every year for Hg) according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur [40 CFR 63.10006(b)]:
   i. For all pollutant emission limits except for Hg, the permittee shall conduct emissions testing quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1) [40 CFR 63.10006(b)(1)].

   ii. For Hg, the permittee shall install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with 40 CFR 63, Subpart 63, Appendix A, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the permittee shall conduct Hg emissions testing quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1). To reestablish LEE status, 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria is required [40 CFR 63.10006(b)(2)].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

h. Except where 40 CFR 63.10006(a) or (b) apply, or where the permittee installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the permittee shall conduct all applicable periodic test for filterable PM, individual, or total HAP metals emission according to Table 5 to 40 CFR 63, Subpart UUUUU, 40 CFR 63.10007, and 40 CFR 63.10000(c), except as otherwise provided in 40 CFR 63.10021(d)(1) [40 CFR 63.10006(c)].

i. Except where 40 CFR 63.10006(b) applies, EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the permittee shall conduct all applicable periodic HCl emissions tests according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007 at least quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1) [40 CFR 63.10006(d)].

j. Time between performance tests performed for 40 CFR 63, Subpart UUUUU [40 CFR 63.10006(f)].
   i. Notwithstanding the provisions of 40 CFR 63.10021(d)(1), and the requirements listed in 40 CFR 63.10006(g) and (h), and the requirements of 40 CFR 63.10006(f)(3), the permittee shall complete performance tests for the EGU as follows: [40 CFR 63.10006(f)(1)].
      1. At least 45 calendar days, measured from the test's end date, shall separate performance tests conducted every quarter [40 CFR 63.10006(f)(1)(i)];

      2. For annual testing [40 CFR 63.10006(f)(1)(ii)]:
         A. At least 320 calendar days, measured from the test's end date, shall separate performance tests [40 CFR 63.10006(f)(1)(ii)(A)];

         B. At least 320 calendar days, measured from the test's end date, shall separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests [40 CFR 63.10006(f)(1)(ii)(B)];

         C. At least 230 calendar days, measured from the test's end date, shall separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests and [40 CFR 63.10006(f)(1)(ii)(C)];

      3. At least 1,050 calendar days, measured from the test's end date, shall separate performance tests conducted every 3 years [40 CFR 63.10006(f)(1)(iii)].

   ii. For units demonstrating compliance through quarterly emission testing, the permittee shall conduct a performance test in the 4th quarter of a calendar year if the EGU has skipped performance tests in the first 3 quarters of the calendar year [40 CFR 63.10006(f)(2)].

   iii. If the EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, the permittee shall complete an additional performance test in that period as follows [40 CFR 63.10006(f)(3)]:
      1. At least 15 calendar days shall separate two performance tests conducted in the same quarter [40 CFR 63.10006(f)(3)(i)].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

2. At least 107 calendar days shall separate two performance tests conducted in the same calendar year [40 CFR 63.10006(f)(3)(ii)].

3. At least 350 calendar days shall separate two performance tests conducted in the same 3 year period [40 CFR 63.10006(f)(3)(iii)].

k. Performance tests conducted for 40 CFR 63, Subpart UUUUU shall be conducted according to 40 CFR 63.10007 and Table 5 to 40 CFR 63, Subpart UUUUU [40 CFR 63.10005(b) and 63.10006].

4. Specific Monitoring Requirements:

a. Continuous emission monitoring systems (CEMS) shall be installed, calibrated, maintained, and operated for measuring PM emissions, SO_2 emissions, oxygen or carbon dioxide emissions, and NO_x emissions. The continuous emission monitoring systems shall comply with 401 KAR 61:005, Section 3 and the applicable Performance Specification in 40 CFR 60, Appendix B or 40 CFR 75, Appendix A [401 KAR 61:005, Section 3 and 401 KAR 52:020, Section 10].

b. The permittee shall sample and record the sulfur, ash, and heat content of the coal burned, as fired, on a daily basis. The daily grab samples shall be averaged to determine the weighted average value for each calendar week. Additionally, all sulfur data obtained in a calendar month shall be averaged to determine the weighted average sulfur content for each calendar month [401 KAR 61:015, Section 6(3)].

c. The permittee shall determine the sulfur content of fuel oil used during startup and determine a monthly average based on fuel supplier certification or a fuel contract [401 KAR 52:020, Section 10].

d. The hourly rate of each fuel burned (coal and fuel oil), the average electrical output, and the minimum and maximum hourly generation rate shall be measured and recorded daily [401 KAR 61:015, Section 6(3)].

e. The Division may provide a temporary exemption from the monitoring and reporting requirements of 401 KAR 61:005, Section 3, for a continuous monitoring system during any period of monitoring system malfunction, provided that the permittee shows, to the Division's satisfaction, that the malfunction was unavoidable and is being repaired as expeditiously as practicable [401 KAR 61:005, Section 3(4)].

f. To demonstrate compliance with the SO_2 emission limits, if any 24-hour average SO_2 value exceeds the standard (excluding periods of startup and shutdown), the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and make any necessary repairs or take corrective actions as soon as practicable [401 KAR 52:020, Section 10].

g. The permittee shall monitor and record the date, time, and duration for each startup and shutdown event [401 KAR 52:020, Section 10].

h. The permittee shall monitor the SCR inlet temperature and record the hourly average temperature [401 KAR 52:020, Section 10].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

i. The permittee shall monitor the wet FGD pump amps and pH and record the hourly averages [401 KAR 52:020, Section 10].

j. To assure compliance with the PM emission limit for the emission unit, the permittee shall [40 CFR 64.6(c)]:
   i. Install, calibrate, maintain and operate a PM CEMS according to Performance Specification 11 in Appendix B to 40 CFR 60;

   ii. The PM CEMS data shall be continuously monitored and recorded to determine hourly average PM emissions.

k. To assure compliance with the SAM emission limit, the permittee shall:
   i. Install, calibrate, and operate a metering system on the sorbent injection system to monitor the sorbent injection rate (lb/hr). The metering system shall be selected to have an accuracy of approximately ± 10% of the target operating range. Additionally, equipment shall be installed, calibrated, and operated as required by the sorbent injection system manufacturer, to monitor the parameters (e.g. unit load and FGD SO_2 inlet) that will be used to monitor the SAM control device operating parameters established by **3. Testing Requirements (d).**

   ii. Install, calibrate, and operate SO_2 CEMS, according to 40 CFR Part 75, at the inlet of the wet FGD and the outlet of the wet FGD stack to determine the average hourly SO_2 removal efficiency for the emission unit. The data shall be averaged to determine the average SO_2 removal efficiency for each operating hour of the day.

   iii. Continuously, once every 15 minutes, monitor and record the sorbent injection rate (lb/hr). The data shall be averaged to determine the average hourly rate for each operating hour of the day.

   iv. The indicator ranges shall be set during the performance test required by **3. Testing Requirements(d)**. An excursion shall be any hourly average that is outside the indicator range established during the performance test.

   v. For each excursion, the permittee shall initiate an investigation, take corrective action, and correct any revealed performance issues in the most expedient manner possible.

   vi. The sorbent injection rate monitoring equipment shall be periodically calibrated and inspected, according to manufacturer recommendations, at least annually. Sorbent injection rate (lb/hr) at or above the indicator ranges set during the testing required by **3. Testing Requirements** (d) are an indicator of the SAM emission control levels [40 CFR 64.6(c)].

l. The permittee shall comply with all applicable monitoring requirements of 40 CFR 63.10010, 40 CFR 63.10011, 40 CFR 63.10020, and 40 CFR 63.10021.

m. The permittee shall monitor and collect data according to 40 CFR 63.10020 and the site-specific monitoring plan required by 40 CFR 63.10000(d) [40 CFR 63.10020(a)].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

i. The permittee shall operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for ~~periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7)), and~~ required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in your site-specific monitoring plan. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable [40 CFR 63.10020(b)].

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ii. The permittee may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee shall use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associate control system [40 CFR 63.10020(c)].

iii. ~~Except for p~~Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities ~~including, as applicable, calibration checks and required~~excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with monitoring system malfunctions or monitoring system out-of-control periods ~~adjustments, failure to collect required data~~ is a deviation from the monitoring system requirements [40 CFR 63.10020(d)].

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of the heat, sulfur and ash content of each fuel on a weekly basis and determine the average sulfur content of each fuel on a monthly basis [401 KAR 52:020, Section 10].

b. The permittee shall maintain records of the amount and rate each fuel is burned, the average electrical output, and the minimum and maximum hourly generation rate on a daily basis [401 KAR 52:020, Section 10].

c. The permittee shall maintain records of the data collected by the continuous monitoring systems, including data necessary to convert monitoring data to the units of the applicable standard [401 KAR 52:020, Section 10 and 40 CFR 64.6(c)].

d. The permittee shall maintain records of the results of all compliance tests [401 KAR 52:020, Section 10].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

e. For each startup and shutdown event, the permittee shall maintain records of the date, time, and duration of each startup and shutdown event. The permittee shall also maintain records of the type of startup event that occurs (cold, warm, hot, etc.). [401 KAR 52:020, Section 10].

f. The permittee shall maintain records of the SCR, wet FGD, and PJFF operating parameters required to be monitored by **4. Specific Monitoring Requirements(h)** and **(i)** and **7. Specific Control Equipment Requirements (b)** [401 KAR 52:020, Section 10].

g. The permittee shall maintain records regarding the maintenance of the wet FGD, SCR, and PJFF [401 KAR 52:020, Section 10 and 40 CFR 64.6(c)].

h. The permittee shall maintain records of the causes and corrective actions taken associated with any exceedance or excursion identified in **4. Specific Monitoring Requirements(j)** and **(k)** [40 CFR 64.6(c)].

i. If 5 percent or more of a unit's operating hours in a calendar quarter report PM exceedances or SAM excursions, as applicable, in accordance with the compliance assurance monitoring in **4. Specific Monitoring Requirements(j)** and **(k)**, then the permittee shall develop and maintain a quality improvement plan (QIP) according to 40 CFR 64.8 [40 CFR 64.6(c)].

j. The permittee shall keep records according to 40 CFR 63.10032(a)(1) and (2). If required or electing to continuously monitor Hg and/or HCl and/or HF emissions, the permittee shall also keep the records required under 40 CFR 63, Subpart UUUUU, Appendix A and/or Appendix B and/or appendix C and/or appendix D [40 CFR 63.10032(a)].
   i. In accordance with 40 CFR 63.10(b)(2)(xiv), a ~~A~~ copy of each notification ~~and~~ or report submitted to comply with 40 CFR 63, Subpart UUUUU, including all records of all supporting for the ~~documentation supporting any~~ Initial Notifications of ~~or Notification of~~ Compliance Status, ~~or~~ semiannual compliance reports, or quarterly compliance reports submitted ~~according to the requirements in 40 CFR 63.10(b)(2)(xiv)~~ [40 CFR 63.10032(a)(1)].

   ii. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii) [40 CFR 63.10032(a)(2)].

k. For each CEMS and CPMS used for 40 CFR 63, Subpart UUUUU, the permittee shall keep records according to 40 CFR 63.10032(b)(1) through (4) [40 CFR 63.10032(b)].
   i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi) [40 CFR 63.10032(b)(1)].

   ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3) {40 CFR 63.10032(b)(2)].

   iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i) [40 CFR 63.10032(b)(3)].

   iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period [40 CFR 63.10032(b)(4)].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

l. The permittee shall keep the records required in Table 7 to 40 CFR 63, Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit applicable to the unit [40 CFR 63.10032(c)].

m. For each EGU subject to an emission limit, the permittee shall also keep the records in 40 CFR 63.10032(d)(1) through (3) [40 CFR 63.10032(d)].
   i. Records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used [40 CFR 63.10032(d)(1)].

   ii. If non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1) are combusted, the permittee shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2) is combusted, the permittee shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee shall keep a record which documents how the fuel satisfies the requirements of the petition process [40 CFR 63.10032(d)(2)].

   iii. For an EGU that qualifies as LEE under 40 CFR 63.10005(h), the permittee shall keep annual records that document that emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year [40 CFR 63.10032(d)(3)].

n. Regarding startup periods or shutdown periods [40 CFR 63.10032(f)]:
   i. If relying on paragraph (1) of the definition of "startup" in 40 CFR 63.10042 for the EGU, the permittee shall keep records of the occurrence and duration of each startup or shutdown [40 CFR 63.10032(f)(1)].

   ii. If relying on paragraph (2) of the definition of "startup" in 40 CFR 63.10042 for the EGU, the permittee shall keep records of [40 CFR 63.10032(f)(2)]:
      1. The determination of the maximum possible clean fuel capacity for each EGU [40 CFR 63.10032(f)(2)(i)].

      2. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU [40 CFR 63.10032(f)(2)(ii)].

      3. The information required in 40 CFR 63.10020(e) [40 CFR 63.10032(f)(2)(iii)].
         A. During each period of startup, the permittee shall record for each EGU [40 CFR 63.10020(e)(1)]:
            I. The date and time that clean fuels being combusted for the purpose of startup begins [40 CFR 63.10020(e)(1)(i)];

            II. The quantity and heat input of clean fuel for each hour of startup [40 CFR 63.10020(e)(1)(ii)];

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

III. The gross output for each hour of startup [40 CFR 63.10020(e)(1)(iii)];

IV. The date and time that non-clean fuel combustion begins and [40 CFR 63.10020(e)(1)(iv)];

V. The date and time that clean fuels being combusted for the purpose of startup ends [40 CFR 63.10020(e)(1)(v)].

B. During each period of shutdown, the permittee shall record for each EGU [40 CFR 63.10020(e)(2)]:

I. The date and time that clean fuels being combusted for the purpose of shutdown begins [40 CFR 63.10020(e)(2)(i)];

II. The quantity and heat input of clean fuel for each hour of shutdown [40 CFR 63.10020(e)(2)(ii)];

III. The gross output for each hour of shutdown [40 CFR 63.10020(e)(2)(iii)];

IV. The date and time that non-clean fuel combustion ends and [40 CFR 63.10020(e)(2)(iv)];

V. The date and time that clean fuels being combusted for the purpose of shutdown ends [40 CFR 63.10020(e)(2)(v)].

C. For PM or non-mercury HAP metals work practice monitoring during startup periods, the permittee shall monitor and collect data according to 40 CFR 63.10020(e)(3) and the site-specific monitoring plan required by 40 CFR 63.10010(l) [40 CFR 63.10020(e)(3)].

o. The permittee shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment [40 CFR 63.10032(g)].

p. The permittee shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation [40 CFR 63.10032(h)].

q. The permittee shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown [40 CFR 63.10032(i)].

r. Records kept for 40 CFR 63, Subpart UUUUU shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). As specified in 40 CFR 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). Records can be kept off site for the remaining 3 years [40 CFR 63.10033].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

6. Specific Reporting Requirements:

a. For each continuous monitoring system, as applicable, the permittee shall submit, in writing to the cabinet, for every calendar quarter, a written report of excess emissions including the nature and cause of the excess emission, if known, as follows [401 KAR 61:005, Section 3(15), 40 CFR 64.6(c)]. The PM Consent Decree data shall be reported in the Semi-Annual Reports [Consent Decree, Paragraph 36]:

i. The averaging period used for data reporting shall correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the applicable pollutant and source category, and quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter;

ii. For PM measurements, the summary shall be based on 24-hour rolling averaging, and 6-hour rolling averaging times OR hourly rolling averages.

iii. For gaseous measurements, the summary shall consist of hourly averages expressed in the units of the applicable standard;

iv. The permittee shall submit any deviations from the sorbent injection rate (lb/hr) indicator ranges. This data or a negative declaration shall be reported semi-annually;

v. Report in the semi-annual reports deviations or a negative declaration of exceedances of the SO_2 emissions from Unit 3 that are above the 0.100 lb/MMBtu 30-day rolling average emission rate limit and below the 97% 30-day rolling average SO_2 removal efficiency limit;

vi. Except for zero and span checks, the date and time of each hourly period during which the continuous monitoring system was not operating, including proof of continuous monitoring system performance during system repairs and the nature of the repairs of adjustments;

vii. If excess emissions have not occurred and the continuous monitoring systems have not been inoperative, repaired or adjusted, this information shall be included in the report; and

viii. All data must be retained for 5 years, but the source shall maintain a file onsite for a minimum of 2 years from the date of collection of the data or submission to the cabinet of:

1. All information reported in the quarterly summaries; and

2. All other data collected by the continuous monitoring systems, including data necessary to convert monitoring data to the units of the applicable standard.

b. The permittee shall submit in the semi-annual report the following information regarding the compliance assurance monitoring for SAM emissions in **4. Specific Monitoring Requirements(k)**:

i. Number of exceedances or excursions;

ii. Duration of each exceedance or excursion;

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

iii. Cause of each exceedance or excursion;

iv. Corrective actions taken on each exceedance or excursion;

v. Number of monitoring equipment downtime incidents;

vi. Cause of each monitoring equipment downtime incident; and

vii. Description of actions taken to implement a quality improvement plan (according to the method in 40 CFR 64.8); and upon completion of the quality improvement plan, documentation that the plan was completed and reduced the likelihood of similar excursions or exceedances [40 CFR 64.9(a)].

c. The permittee shall report exceedances that occur as a result of startup on a semi-annual basis. The report shall include the type of start-up and whether or not the duration of the startup exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the startup exceeded recommended or typical durations [401 KAR 52:020, Section 10].

d. The permittee shall report the SAM emissions 12-month rolling totals on a semi-annual basis according to **Section F – Monitoring, Recordkeeping, and Reporting Requirements** [401 KAR 52:020, Section 10].

e. The permittee shall submit a semiannual compliance report which shall contain [40 CFR 63.10031(~~a~~c) referencing Item ~~1~~9. of Table 8 to Subpart UUUUU of Part 63]:
   i. The compliance report shall contain the information required in 40 CFR 63.10031(c)(1) through (~~9~~10).
      1. The information required by the summary report located in 40 CFR 63.10(e)(3)(vi) [40 CFR 63.10031(c)(1)].

      2. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or the permittee's basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure [40 CFR 63.10031(c)(2)].

      3. Indicate whether new types of fuel were burned during the reporting period. If new types of fuel were burned, the permittee shall include the date of the performance test where that fuel was in use [40 CFR 63.10031(c)(3)].

      4. Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed [40 CFR 63.10031(c)(4)].

      5. If relying on paragraph (2) of the definition of "startup" in 40 CFR 63.10042 for the EGU, for each instance of startup or shutdown the permittee shall [40 CFR 63.10031(c)(5)]:

Commented [MZ58]: KDAQ - Need to add 63.10031(a), similar to Trimble's permit.

e. For Emission Unit 03, the permittee shall submit each of the following reports that apply: [40 CFR 63.10031(a)]
i. If the permittee elects to monitor Hg emissions continuously, the permittee shall meet the electronic reporting requirements of Appendix A to 40 CFR 63, Subpart UUUUU. [40 CFR 63.10031(a)(1)]
ii. In regards to PM CEMS, the permittee shall meet the electronic reporting requirements of Appendix C to 40 CFR 63, Subpart UUUUU. Electronic reporting of hourly PM emissions data shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial PM CEMS correlation test. [40 CFR 63.10031(a)(3)]
iii. In regards to SO2 CEMS, the permittee shall use the ECMPS Client Tool to submit the information required in 40 CFR 63.10031(a)(5)(i) through (iii) to EPA (except where it is already required to be reported or has been previously provided under the Acid Rain Program or another emissions reduction program that requires the use of 40 CFR part 75. [40 CFR 63.10031(a)(5)]
iv. PDF reports for all RATAs of Hg, HCl, HF, and/or SO2 monitoring systems completed prior to January 1, 2024, and for correlation tests, RRAs and/or RCAs of PM CEMS completed prior to January 1, 2024, according to 40 CFR 63.10031(f)(1) and (6) and Table 8 to 40 CFR 63, Subpart UUUUU. [40 CFR 63, Subpart UUUUU, Table 8, Item 7.]
v. Quarterly reports, in PDF files, that include all 30-boiler operating day rolling averages in the reporting period derived from the PM CEMS, according to 40 CFR 63.10031(f)(2) and (6). [40 CFR 63, Subpart UUUUU, Table 8, Item 8.]

Commented [MZ59]: KDAQ - Also need to add the following:

f. For Emission Unit 03, the final quarterly averages report in PDF files shall cover the fourth calendar quarter of 2023. Starting with the first quarter of 2024, the permittee shall report all 30-boiler operating day rolling averages for PM CEMS, Hg CEMS, Hg sorbent trap systems, and SO2 CEMS (or 90-boiler operating day rolling averages for Hg systems), in XML format, in the quarterly compliance reports required under 40 CFR 63.10031(g). The quarterly compliance reports shall be submitted no later than 60 days after the end of each calendar quarter. [40 CFR 63, Subpart UUUUU, Table 8, Item 8.]

g. For Emission Unit 03, the permittee shall submit semi-annual compliance reports according to the requirements in 40 CFR 63.10031(b)(1) through (5) [40 CFR 63.10031(b)]. The report shall contain the information required in 40 CFR 63.10031(c)(1) through (10) [40 CFR 63.10031(c)] and excess emissions and monitor downtime summary report described in 40 CFR 63.10(e)(3)(vi) [40 CFR 63.10031(d)]. The final semiannual compliance report shall cover the reporting period from July 1, 2023 through December 31, 2023 [40 CFR 63.10031(b)(6)].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

A. Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of 40 CFR 63.10032(f) [40 CFR 63.10031(c)(5)(i)].

B. Include the information required to be monitored, collected, or recorded according to the requirements of 40 CFR 63.10020(e) [40 CFR 63.10031(c)(5)(ii)].

~~C. If using CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO_2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values [40 CFR 63.10031(c)(5)(iii)].~~

~~D. If using a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter [40 CFR 63.10031(c)(5)(iv)].~~

~~E. If using a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation [40 CFR 63.10031(c)(5)(v)].~~

6. Emergency bypass information annually from EGUs with LEE status [40 CFR 63.10031(c)(6)].

7. A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If stack tests are conducted once every 3 years to maintain LEE status, consistent with 40 CFR 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in 40 CFR 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions [40 CFR 63.10031(c)(7)].

8. A certification [40 CFR 63.10031(c)(8)].

9. If there was a deviation from any emission limit, work practice standard, or operating limit, the permittee shall also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation [40 CFR 63.10031(c)(9)].

~~9.~~10. If you had any process or control equipment malfunction(s) during the reporting period, you must include the number, duration, and a brief description for each type of malfunction which occurred during the semiannual reporting period which caused or may have caused any applicable emission limitation to be exceeded [40 CFR 63.10031(c)(10)].

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

ii. Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in paragraph (c) of this section must include the excess emissions and monitor downtime summary report described in 40 CFR 63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR 63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and you must, instead, include in the quarterly compliance reports described in paragraph (g) of this section the applicable data elements in section 13 of appendix E to this subpart for any "deviation" (as defined in 40 CFR 63.10042 and elsewhere in this subpart) that occurred during the calendar quarter. If there were no deviations, you must include a statement to that effect in the quarterly compliance report~~If there are no deviations from any emission limitation (emission limit and operating limit) applicable to the EGU and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR 63, Subpart UUUUU, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period~~ [40 CFR 63.10031(~~a~~d)~~ referencing Item 1.b. of Table 8 to Subpart UUUUU of Part 63~~].

iii. Each affected source that has obtained a title V operating permit pursuant to part 70 or part 71 of this chapter 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 semiannual compliance report pursuant to paragraphs (c) and (d) of this section, or two quarterly compliance reports covering the appropriate calendar half pursuant to paragraph (g) of this section, 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(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority~~If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report shall contain the information in 40 CFR 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report shall contain the information in 40 CFR 63.10031(c)~~ [40 CFR 63.10031(~~a~~e)~~ referencing Item 1.c. of Table 8 to Subpart UUUUU of Part 63~~].

iv. ~~If there was a malfunction during the reporting period, the compliance report shall 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~~ Starting with a report for the first calendar quarter of 2024, you must use the ECMPS Client Tool to submit quarterly

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of appendix E to this subpart. For each stack test summarized in the compliance report, you must also submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter [40 CFR 63.10031(g)].

v. On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR 63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each Notification [40 CFR 63.10031(h)].

vi. If you have elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each startup and shutdown report [40 CFR 63.10031(i)].

vii. If you elect to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with this subpart and have begun recording valid data from the PM CEMS prior to November 9, 2020, you must use the ECMPS Client Tool to submit a detailed report of your PS 11 correlation test (see appendix B to part 60 of this chapter) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, you must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, you must submit the PDF report according to section 7.2.4 of appendix C to this subpart. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report [40 CFR 63.10031(j)].

~~iv.~~viii. If you elect to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, you must submit quarterly reports of your QA/QC activities (e.g., calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report [40 CFR 63.10031(k)].

f. The permittee shall submit reports to U.S. EPA as required by 40 CFR 63.10031(f).

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SECTION H - ALTERNATE OPERATING SCENARIOS (CONTINUED)

g. The permittee shall certify that EU03 (Unit 3 Boiler) ceased operation upon commencement of normal operation of EU58 (Unit 12 Combustion Turbine). This certification shall be made in the semiannual monitoring report submitted according to **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for the six-month period during which EU58 commenced normal operation. [401 KAR 52:020, Section 10]

Commented [AA60]: Approval deferred to 2030

h. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. <u>Specific Control Equipment Operating Conditions</u>:

a. The wet FGD and SCR shall be operated to maintain compliance with permitted emission limitations, and in accordance with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. The permittee shall continuously operate the PJFF to maximize PM emission reductions at all times when the unit is in operation, provided that such operation of the PJFF is consistent with the technological limitations, manufacturer's specifications and good engineering and maintenance practices for the PJFF. Except as required during correlation testing under 40 CFR 60, Appendix B, Performance Specification 11, and Quality Assurance Requirements under Appendix F, Procedure 2, the permittee shall, at a minimum:

i. Monitor stack PM CEMS output to ensure that the PJFF is operating properly;

ii. Promptly repair, replace, or remove leaking bags identified through monitoring or inspection; and;

iii. Inspect the PJFF casing, ductwork, and expansion joins for openings or leakage and make any necessary repairs during the next scheduled Unit outage or unscheduled Unit outage of sufficient length. [Consent Decree, Paragraph 29A and 401 KAR 52:020, Section 10]

c. The permittee shall continuously operate the wet FGD whenever the emission unit is in operation. This is a permanent federally-enforceable operating requirement [Consent Decree, Paragraph 20].

d. The permittee shall continuously operate the existing low NO_x burners and over-fire air for the emission unit. This is a permanent federally-enforceable operating requirement [Consent Decree, Paragraph 8].

~~e. The permittee shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment [40 CFR 63.10023~~10032~~(g)].~~

Commented [MZ61]: KDAQ - This is already referenced above.

f. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION K - CLEAN AIR INTERSTATE RULE (CAIR)

1. **Statutory and Regulatory Authority:**
In accordance with KRS 224.10-100, the Kentucky Energy and Environmental Cabinet issues this permit pursuant to 401 KAR 52:020, Title V permits, 401 KAR 51:210, CAIR NO_X annual trading program, 401 KAR 51:220, CAIR NO_X ozone season trading program, and 401 KAR 51:230, CAIR SO_2 trading program.

2. **Permit Requirements:**
This CAIR Permit covers CAIR Units 3 and 5-11 (Emission Units 3 and 23-29) at the E.W. Brown plant (ORIS Code: 001355). Unit 3 is a coal-fired based load electric generating unit. Units 5-11 are natural gas- or distillate oil-fired peaking combustion turbines. The CAIR application for ten electrical generating units was submitted to the Division and received on July 3, 2007. The standard requirements and special provisions set forth in the application are hereby incorporated into and made part of this CAIR Permit. [401 KAR 51:210, 401 KAR 51:220, and 401 KAR 51:230]

3. **Compliance Plan:**
(a) The permittee shall operate in compliance with the requirements contained in the CAIR application and incorporated into this permit [40 CFR 96.106, 40 CFR 96.206, 40 CFR 96.306].

(b) The permittee shall not sell, trade, or transfer any NO_X allowances allocated to Emission Unit 03 that would otherwise be available for sale, trade, or transfer as a result of the actions taken by the permittee to comply with the Consent Decree. The NO_X allowances allocated to Emission Unit 03 (CAIR Unit 3) may be used by the permittee only to meet its own federal and/or state Clean Air Act regulatory requirements for Emission Unit 03. This is a permanent federally enforceable limit. [Consent Decree, Paragraph 12]

(c) For each calendar year beginning with 2009 and continuing through calendar year 2020, the permittee shall surrender to EPA, or transfer to a non-profit third party, Surplus NO_X Allowances. This is a permanent federally enforceable limit. [Consent Decree, Paragraph 13]

(d) Nothing shall preclude the permittee from selling or transferring NO_X allowances allocated to Emission Unit 03 (CAIR Unit 3) that become available for sale or trade solely as a result of the achievement and maintenance of a NO_X emission rate below a 30-day rolling average emission rate for NO_X of 0.070 lb/MMBtu [Consent Decree, Paragraph 17].

Commented [WJ71]: KDAQ - Can these items of Section K be removed, similar to the Section K found in LG&E Trimble County Title V operating permit (V-22-028)?

CSAPR implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule.

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SECTION L - CROSS-STATE AIR POLLUTION RULE

Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions at this source, are identified in the following tables. These units are subject to the requirements for the CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season ~~Group 3~~Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program

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
Unit ID: Emission Unit 3 (Unit 3)					
SO_2	X		----------		
NO_X	X	----------			
Heat input	X		----------		
Unit ID: Emission Unit 23 (Unit 9); Emission Unit 24 (Unit 10); Emission Unit 25 (Unit 8); Emission Unit 26 (Unit 11); Emission Unit 27 (Unit 6); Emission Unit 28 (Unit 7); Emission Unit 29 (Unit 5)					
SO_2		X	----------	~~X~~	
NO_X		----------	X		
Heat input	X		----------		
Unit ID: Emission Unit 58 (Unit 12, non-peaking natural-gas fired combustion turbine with natural gas-fired duct burners)					
SO_2		X			
NO_X	X				
Heat input		X			

Commented [WJ72]: KDAQ - We should have caught it in the application; but we are not using LME for SO2 on the simple cycle CTs. We have always been using 40 CFR 75 Appendix D.

Commented [WJ73]: KDAQ - Please remove "------" from the table.

Commented [AA74]: Approval deferred to 2030

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

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 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(30) (CSAPR NO_x Annual Trading Program), 40 CFR 97.1030 through 40 CFR 97.1035 (CSAPR NO_x Ozone Season Group 3 Trading Program), and 401 KAR 51:260 Section 3(25) through 401 KAR 51:260, Section 3(30) (CSAPR SO_2 Group 1 Trading Program). The monitoring, recordkeeping, and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR 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: http://www.epa.gov/airmarkets.

3. Owners and operators that want to use an alternative monitoring system shall submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR 75, Subpart E, 40 CFR 75.66, 401 KAR 51:240, Section 3(30) (CSAPR NO_X Annual Trading Program), 40 CFR 97.1035 (CSAPR NO_X Ozone Season Group 3 Trading Program), and/or 401 KAR 51:260, Section 3(30) (CSAPR SO_2 Group 1 Trading Program). 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/part-75-petition-responses.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirements under 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(29) (CSAPR NO_x Annual Trading Program), 40 CFR 97.1030 through 40 CFR 97.1034 (CSAPR NO_x Ozone Season Group 3 Trading Program), and/or 401 KAR 51:260, Section 3(25) through 401 KAR 51:260, Section 3(29) (CSAPR SO_2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 401 KAR 51:240, Section 3(30) (CSAPR NO_x Annual Trading Program), 40 CFR 97.1035 (CSAPR SO_2 Group 1 Trading Program), and 401 KAR 51:260, Section 3(30) (CSAPR NO_x Ozone Season Group 3 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the EPA's website at https://www.epa.gov/airmarkets/data-resources.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(29) (CSAPR NO_x Annual Trading Program), 40 CFR 97.1030 through 40 CFR 97.1034 (CSAPR NO_x Ozone Season Group 3 Trading Program), and 401 KAR 51:260, Section 3(25) through 401 KAR 51:260, Section 3(29) (CSAPR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B), may be used to add or change this unit's monitoring system description.

CSAPR NO_x Annual Trading Program requirements (401 KAR 51:240, Section 3(4))

a) 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 401 KAR 51:240, Section 3(10) through 401 KAR 51:240, Section 3(15).

Commented [MZ75]: KDAQ - Many changes are needed here because of the Federal Register changes that have occurred in June and July of 2023. See 88 FR 36890, June 5, 2023; 88 FR 49303, July 31, 2023.

Commented [WJ76R75]: KDAQ - This is the same as previously noted...
With the stay of the SIP disapprovals, KY is not applicable to the Group 3 trading program.
With the Interim Final Rule, published on August 4, 2023, KY EGUs are now back in 40 CFR 97 Subpart EEEEE and operating in a new "Expanded G2" NOx ozone season trading program per 52.38(b)(14).
So it seems like all GGGGG references should be changed to appropriate EEEEE/Expanded G2 references, including the first sentence (above) of Section L.

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a PPL company

March 25, 2025

Mr. Zachary Bittner
Permit Review Branch Manager
Kentucky Division for Air Quality
300 Sower Boulevard, 2nd Floor
Frankfort, KY 40601

RE: Title V Air Permit Revision Application for NGCC Unit 12
Kentucky Utilities Company – E.W. Brown Generating Station; Agency Interest #3148

Dear Mr. Bittner:

Kentucky Utilities Company (KU) currently operates the E.W. Brown Generating Station (Brown Generating Station) located outside of Harrodsburg, Kentucky in Mercer County. The facility is classified as a major source under the Title V Operating Permit Program and currently operates in accordance Title V Permit No. V-17-030 R1. KU submitted the renewal application on December 6, 2023, within the 6-month timeframe before expiration.

KU is proposing to install and operate a new 681 MW (gross) natural gas-fired combined cycle (NGCC) electric generating unit (EGU) (Unit 12) and all its associated auxiliary operations. KU will utilize and optimize the current electrical transmission system in conjunction with completing the NGCC Project to the extent feasible, as well as tap into an existing natural gas pipeline on the property to serve the new EGU. The proposed Unit 12 will be located within the existing Brown Station property near the location of the existing Unit 3 coal boiler, which will allow for considerable utilization of existing site infrastructure including transmission connectivity.

As the NGCC Project results in air emissions exceeding significance thresholds for PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4 mists, and GHG, it results in a *major modification* to an *existing major stationary source* and is subject to the New Source Review (NSR) permitting program. Pursuant to 401 KAR 51:017, Section 1, a project at an *existing major stationary* source located in an area designated as attainment or unclassifiable that meets the definition of a *major modification* is required to conduct a Prevention of Significant Deterioration (PSD) permitting review, including a Best Available Control Technology (BACT) analysis, a Source Impact Analysis, an Air Quality Analysis, and an Additional Impacts Analysis. Through this application containing all required elements under KAR 401 KAR 52:020 and 401 KAR 51:017, KU is seeking an initial issuance of a PSD construction permit and a significant permit revision to the Title V permit authorizing the planned installation and operation of the proposed NGCC Project.

Unit 12 will consist of one natural gas-fired gas combustion turbine, a steam turbine, and one heat recovery steam generator with natural gas-fired duct burners arranged in a one-on-one configuration. Unit 12 will utilize dry-low-NO_X combustors in the gas turbine and low-NO_X duct burners in the HRSG. It will also be equipped with an oxidation catalyst and Selective Catalytic Reduction as add-on control systems to reduce stack NO_X, CO, hydrocarbons, and organic hazardous air pollutant emissions. The use of a highly efficient combined cycle 1 x 1 gas turbine and HRSG unit will also minimize greenhouse gas emissions by extracting

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the maximum amount of usable energy from the fuel gas, thus minimizing the amount of natural gas required to be combusted to generate electricity.

The state-of-the-art technology design features, as well as the selected control measures, set the BACT emission limits and operational restrictions for the regulated NSR pollutants.

An evaluation of ambient air impacts due to the NGCC Project in the area surrounding the existing Brown Station, which is designated as a Class II area, and regional Class I areas within 300 km, require use of air dispersion modeling. The Class II analyses supporting this Project demonstrate that the Project will not cause or contribute to an exceedance of any NAAQS or any Class II PSD Increments. In the Class I analysis, compliance is demonstrated for Class I PSD Increment. Additionally, per Federal Land Manager (FLM) guidance, no Air Quality Related Values (AQRV) analysis would be required. An Additional Impacts Analysis, consisting of an assessment of growth associated with the proposed project, an assessment of potential impacts of the proposed Project on soils and vegetation, and a Class II visibility analysis, also demonstrates no adverse impacts.

The NGCC EGU will also be subject to Federal New Source Performance Standards (NSPS) codified in 40 CFR Part 60 and National Emission Standards for Hazardous Air Pollutants (NESHAP) codified in 40 CFR Part 63. These NSPS and NESHAP standards require certain operating practices and emission controls for emission source categories, which will serve to mitigate air emissions from the proposed NGCC Unit.

Compliance with State and Federal preconstruction air permitting requirements, NSPS and NESHAP emission controls requirements, Class II area dispersion modeling, and additional impact analyses ensure that the NGCC Project will have no significant air quality impacts. Coupled with these air quality conclusions, the planned project will bring a major new capital investment to the Brown Generating Station and help ensure that it remains a critical asset for the company to meet the energy needs of its customers for several decades. We look forward to working in cooperation with Kentucky Division for Air Quality (Division) personnel to help ensure the timely and successful completion of this permit action. To support the project procurement timeline, KU is requesting to obtain the Proposed Permit authorizing construction for the project by **January 1, 2026**.

If you or any other Division staff have any questions or need additional information as you initiate your review of the application, please do not hesitate to contact me at (502) 627-2791 or brandan.burfict@lge-ku.com.

Sincerely,

Signed by:
[signature]
[illegible]

Brandan Burfict
Sr. Manager, Environmental Generation and Gas Operations

Enclosure

cc: Mr. Philip Imber, Director, Environmental Compliance, PPL
Mr. Jason Wilkerson, Principal Engineer, LG&E and KU
Mr. Steven Turner, Vice President Power Production, LG&E and KU
Mr. Greg Wilson, General Manager, E.W. Brown Station, LG&E and KU
Mr. Michael Zimmer, P.E., Principal Consultant, Trinity Consultants
Mr. Harrison Rae, Senior Consultant, Trinity Consultants

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PSD PERMIT APPLICATION

NGCC EGU Project / Harrodsburg, KY

a PPL company

Kentucky Utilities Company / E.W. Brown Generating Station

Prepared By:

Michael Zimmer, P.E. – Principal Consultant
Harrison Rae - Senior Consultant

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March 24, 2025

Project 241801.0161

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1. APPLICATION SUMMARY

Kentucky Utilities Company (KU) currently operates the E.W. Brown Generating Station (Brown Station) located outside of Harrodsburg, Kentucky in Mercer County. The facility is classified as a major source under the Title V Operating Permit Program, Prevention of Significant Deterioration (PSD) construction permitting program, and National Emissions Standards for Hazardous Air Pollutants (NESHAP) federal regulatory program. The Brown Station currently operates in accordance with Title V Permit No. V-17-030 R1, issued by the Kentucky Division for Air Quality (Division) on June 8, 2019, and most recently revised on July 16, 2021. KU submitted the renewal application on December 6, 2023, within the 6-month timeframe before expiration.

1.1 Project Overview and Purpose

KU is proposing to install and operate a one-on-one (1x1) Natural Gas Combined Cycle Turbine (NGCC) electric generating unit (EGU) with integrated NG duct burners (DB or DBs) at the E.W. Brown Generating Station (herein labeled as the NGCC EGU Project) to produce steam for the generation of electricity. The maximum gross power design rating is approximately 681 MW-g. KU will utilize and optimize the current electrical transmission system in conjunction with completing the NGCC EGU Project to the extent feasible, as well as tap into an existing natural gas pipeline on the property to serve the new NGCC EGU. The proposed NGCC EGU will be located within the existing Brown Station property near the location of the existing Unit 3 coal boiler, which will allow for considerable utilization of existing site infrastructure including transmission connectivity.

This project includes the following ancillary equipment:

- Auxiliary boiler
- Fuel gas (dewpoint) preheater
- Cooling tower
- Emergency generator/engine
- Emergency firewater pump engine
- Process vents
- SF6 circuit breaker
- Haul roads
- Natural gas piping fugitives
- Storage tanks

This project is defined as a major modification to an existing major stationary source and is subject to the New Source Review (NSR) permitting program.

Pursuant to 401 KAR 51:017, Section 1, a project at an existing major stationary source located in an area designated as attainment or unclassifiable that meets the definition of a *major modification* [refer to 401 KAR 51:001 Section 1(114)] is required to conduct a PSD permitting review, including a Best Available Control Technology (BACT) analysis (401 KAR 51:017 Section 8), a Source Impact Analysis (401 KAR 51:017 Section 9), an Air Quality Analysis (401 KAR 51:017 Section 11), and an Additional Impacts Analysis (401 KAR 51:017 Section 13). Through this application containing all required elements under Kentucky Administrative Regulations (KAR) 401 KAR 52:020 and 401 KAR 51:017, KU is seeking an initial issuance of a PSD construction permit and a significant permit revision (SPR) to the Title V permit authorizing the planned installation and operation of the proposed NGCC EGU Project.

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1.2 Project Schedule

KU is targeting for commercial operation of new NGCC Unit to begin no later than June 1, 2030. Given the time needed for construction and commissioning, the anticipated start of construction will be June 22, 2026. Additional time will be needed for KU to finalize contracts with major equipment suppliers for the project well ahead of this construction target date and these contracts generally cannot be finalized until the air construction permit is obtained due to the financial commitments involved. Therefore, to satisfy KU's mandate and obligations to provide safe, reliable electrical power to the market, it is important that construction authority for this project be obtained in a timely manner. KU will be seeking opportunities to proactively engage with Division staff and is committed to providing information and/or responses to any questions promptly to allow the agency's review and processing of this application and development of an amended Title V permit to proceed smoothly on a timely basis. KU's requests to obtain the Proposed Permit by **January 1, 2026**.

1.3 Brown Station Background

Brown Station is classified as a major source under the Title V permit program and is an existing major stationary source under the PSD program.

Brown Station is an electrical generating power plant that began operation in the 1950s. The primary emission unit at the plant is one coal-fired utility boiler (Unit 3). Seven combustion turbines are also present that are used to provide peaking power. Previously, there were three large coal-fired utility boilers at the plant. However, KU submitted a minor permit revision to the Division on March 13, 2019, to retire Units 1 and 2. They were officially retired on March 1, 2019.

Unit 3 began service in 1971 and is still in operation. Unit 3 is a pulverized coal, dry bottom, tangentially-fired boiler. It has a heat input capacity of 5,300 MMBtu/hr and a nameplate power output rating of 464 MW. Air pollution controls on Unit 3 consist of low NO_X burners (LNBs), Selective Catalytic Reduction (SCR), a powdered activated carbon (PAC) injection system, a dry sorbent injection (DSI) system (and/or liquid additive system), a pulse-jet fabric filter (PJFF) baghouse, and a wet flue gas desulfurization (WFGD) unit.

In addition to the potential 464 MW generated from Unit 3; the Brown Generating Station also has a 33 MW hydroelectric plant, a 10 MW solar facility, and 981 MW of capacity from seven simple-cycle natural gas-fired combustion turbines (CT).

1.3.1 Existing Permitted Emission Units

Brown Station's current Title V Permit authorizes the operation of the following emission units/activities:

- EU03 – Pulverized coal- dry bottom- tangentially-fired indirect heat exchanger
- EU07 & EU35 – Fugitive Emissions (consisting of one (1) track hopper, five (5) conveyors, and paved and unpaved roadways)
- EU35 – Paved and Unpaved Roadways
- EU09 – Fugitive Coal Handling Operations (consisting of one (1) track hopper, four (4) conveyors, and one (1) coal stockpile)
- EU13 & EU16 – Coal Handling Operations (consisting of three (3) conveyors, and coal crushing)
- EU38 – Cooling Tower 3

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- EU23 – Combustion Turbine (Unit 9)
- EU24 – Combustion Turbine (Unit 10)
- EU25 – Combustion Turbine (Unit 8)
- EU26 – Combustion Turbine (Unit 11)
- EU27 – Combustion Turbine (Unit 6)
- EU28 – Combustion Turbine (Unit 7)
- EU29 – Combustion Turbine (Unit 5)
- EU30, EU31, EU32, EU33, & EU34 – Limestone Handling (consisting of two (2) limestone truck dump stations, one (1) limestone stacking tube, and two (2) limestone reclaim conveyors)
- EU39 – Existing 4SLB SI Emergency RICE (Dix Dam Crest Gate Emergency Generator)
- EU40 – Existing CI Emergency RICE <500 HP (Brown Station Emergency Generator)
- EU41 – Existing CI Emergency RICE <500 HP (CT5 Emergency Generator)
- EU42 – Existing CI Emergency RICE <500 HP (CT6 Emergency Generator)
- EU43 – Existing CI Emergency RICE <500 HP (CT7 Emergency Generator)
- EU44 – Existing CI Emergency RICE <500 HP (CT Area Fire Pump Engine)
- EU45 – New CI Emergency Fire Pump RICE (Steam Plant Emergency Fire Pump Engine #1)
- EU46 – New CI Emergency Fire Pump RICE (Steam Plant Emergency Fire Pump Engine #2)
- EU47 – New Emergency CI RICE (Emergency Quench Water Pump Engine #1)
- EU48 – New Emergency CI RICE (Emergency Quench Water Pump Engine #2)
- EU49 – New Emergency CI RICE (Doosan Model 390)
- EU51 & EU52 – New Emergency CI RICE (Two (2) Cummins QSK23-G7 NR2 emergency engines)
- EU50 – CCR Landfill Operations and Haul Trucks
- EU55, EU56, & EU57 – Natural Gas Process Heaters (consisting of three (3) natural gas preheaters)
- Insignificant Activities (IA)

1.4 Air Permitting Program Applicability

Mercer County is currently designated as an attainment or unclassified area for all criteria pollutants with respect to the National Ambient Air Quality Standards (NAAQS).[1] The facility is currently classified as an existing major stationary source under the PSD permitting program. Since the NGCC Project will be constructed and operated within the existing Brown Generating Station property, it will have the same standard industrial classification (SIC) code as existing operations and will be under the same common control and/or ownership, the NGCC Project will be considered a *modification* to an existing major stationary source. Therefore, the applicability of the PSD permitting program is evaluated for the NGCC Project to assess the PSD triggering status of the overall project emissions increase.

[1] 40 CFR 81.318

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Table 1-1 provides a summary of emission increases of regulated NSR pollutants associated with the proposed project.

Table 1-1. Project Emission Increases and PSD Applicability

Pollutant	"Step 1" Project Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Project Triggers PSD Review? (Yes/No)
PM	**102.0**	25	Yes
PM_{10}	**101.7**	15	Yes
$PM_{2.5}$	**100.7**	10	Yes
NO_X	**169.2**	40	Yes
CO	**148.9**	100	Yes
VOC	**67.2**	40	Yes
SO_2	27.2	40	No
H_2SO_4	**23.7**	7	Yes
Lead	0.001	0.6	No
GHG (as CO_2e)	**2,321,537**	75,000	Yes

As shown in the table, the pollutants triggering PSD permitting requirements include particulate matter (PM), PM 10 microns or less in diameter (PM_{10}), PM 2.5 microns or less in diameter ($PM_{2.5}$), oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), sulfuric acid (H_2SO_4) mists, and greenhouse gases (GHG). KU provides Best Available Control Technology (BACT) analyses for each pollutant triggering PSD permitting requirements within this application, with proposed BACT emission rates forming the basis of the emission calculations for each emission unit.

Emission units associated with the project will be subject to New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAP), and several Kentucky State Implementation Plan (SIP) air quality regulations. The facility is currently classified as a major source of hazardous air pollutants (HAPs) and will retain this classification following the completion of the project.

1.5 Air Quality Analysis

The modeling analyses performed for the project include an evaluation of ambient impacts due to the NGCC EGU Project in the area surrounding the existing Brown Station, which is designated as a Class II area, and regional Class I areas within 300 km. The Class II analyses provided in Volume 2 demonstrate that the project will not cause or contribute to an exceedance of any NAAQS or any Class II PSD Increments. In the Class I analysis also provided in Volume 2, compliance is demonstrated for Class I PSD Increment. Additionally, per Federal Land Manager (FLM) guidance, no Air Quality Related Values (AQRV) analysis is required. An Additional Impacts Analysis, consisting of an assessment of growth associated with the proposed project, an assessment of potential impacts of the proposed project on soils and vegetation, and a Class II visibility analysis, is also included in Volume 2 of this application.

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1.6 Summary of Application Contents

The permit application is organized as follows:

- Section 2 provides relevant background information about the Brown Generating Station and information about the proposed new Unit 12 NGCC operations.
- Section 3 discusses the emissions calculation methodologies used to define the potential emissions from the new emission units/ancillary equipment associated with the NGCC EGU Project and provides a summary of the total emissions by pollutant.
- Section 4 presents the methodology used to calculate project emission increases and net emissions increases, and the PSD applicability analysis.
- Section 5 provides a summary review of applicable regulatory requirements under state and federal air quality programs impacted by the NGCC EHU Project.
- Sections 6 through Section 8 provide a complete top-down BACT analysis.
- Section 9 provides a summary of proposed BACT.
- **Appendix A** contains both area and aerial maps that show the location of the Brown Generating Station relative to nearby geographic features, site arrangement drawings for the new NGCC Unit within the existing facility, and a process flow diagram showing both the new emission units being installed as part of the project.
- **Appendix B** provides an inventory of the existing and new proposed emission units at Brown Station; a derivation of potential emissions from the new emission units associated with the NGCC EGU Project; and a project emission increase summary for evaluating PSD applicability. The Division should use the Brown Station Emission Unit Index as a guide to identify the new emissions units (**bold green font**), EUs to be removed from the site in CY2025 that are un-related to the project (~~red, strikethrough font~~), and revisions to existing units that are unrelated to the project (light green highlight).
- **Appendix C** includes the DEP7007 series application forms required for processing of the application along with a copy of the acid rain program revision application for this project.
- **Appendix D** and **Appendix E** provide supporting BACT documentation.
- **Appendix F** provides a suggested permit incorporating the proposed operations.

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2. PROJECT DESCRIPTION

This section describes the NGCC EGU Project that will be installed and operated at the existing Brown Station.

2.1 Site Location

Brown Generating Station is located approximately 25 miles southwest of Lexington and 7.5 miles east-northeast of Harrodsburg, Kentucky (Mercer County) along the west shore of Lake Herrington in the Dix River Valley. The property encompasses an area of approximately 1,222 acres.

Figure A-1 in **Appendix A** shows the facility location and the surrounding area on a topographical map. The Universal Transverse Mercator (UTM) coordinates of the Brown Generating Station's center are (approximately) 701.319 kilometers (km) East and 4,184.791 km North (Zone 16, NAD83). As shown in Figure A-3 in **Appendix A**, the proposed NGCC Unit will be located on property currently owned by KU and occupied by KU's existing Brown Station. Whereas, Figures A-4 and A-5 depict a detailed site layout of the proposed NGCC Unit components relative to the existing site operations.

2.2 Background on Existing Site Operations and Emission Units

Brown Generating Station is an electrical generating power plant that began operation in the 1950s. The primary emission unit at the plant is one coal-fired utility boiler (Unit 3). Seven combustion turbines are also present that are used to provide peaking power. Previously, there were three large coal-fired utility boilers at the plant. However, KU submitted a minor permit revision to the Division on March 13, 2019, to retire Units 1 and 2. They were officially retired on March 1, 2019. Unit 1 was a dry bottom, wall-fired designed boiler with a heat input capacity of 1,260 MMBtu/hr and a nameplate power output rating of 114 MW. Unit 2 was a dry bottom, tangentially-fired boiler design with a heat input capacity of 1,733 MMBtu/hr and a nameplate power output rating of 180 MW.

Unit 3 began service in 1971 and is still in operation. Unit 3 is a pulverized coal, dry bottom, tangentially-fired boiler. It has a heat input capacity of 5,300 MMBtu/hr and a nameplate power output rating of 464 MW. Air pollution controls on Unit 3 consist of low NO_X burners (LNBs), Selective Catalytic Reduction (SCR), a powdered activated carbon (PAC) injection system, a dry sorbent injection (DSI) system (and/or liquid additive system), a pulse-jet fabric filter (PJFF) baghouse, and a wet flue gas desulfurization (WFGD) unit. The unit is equipped with PM, SO_2, NO_X, and CO_2 CEMS, a mercury emission monitor, and a flowrate monitor at the stack.

In addition to the potential 464 MW generated from Unit 3; the Brown Generating Station also has a 33 MW hydroelectric plant, a 10 MW solar facility, and 981 MW of capacity from seven simple-cycle GTs.

2.3 Proposed NGCC EGU Project

This section describes aspects of the proposed NGCC EGU Project associated with the NGCC EGU Project, including proposed operations and equipment.

2.3.1 NGCC EGU Project Overview

With this application, KU will install and operate a 1x1 NGCC Unit. KU will utilize and optimize the current electrical transmission system, as well as tap into an existing NG pipeline on the property to serve the new

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NGCC unit. The proposed NGCC unit will be capable of operating as a baseload unit, quickly and efficiently dispatched when renewables are not available, and dispatched when there is sudden high demand from customers.

KU plans to install the following:[2]

- One NG-fired GT (EU58) (7HA.03 gas turbine) equipped with NG-fired DBs in the HRSG arranged in a one-on-one configuration to a single steam turbine (ST) generator) with a gross power output of 681 MWh-g. The GT will have a maximum heat input capacity on NG of 4,525 MMBtu/hr when firing DBs and 3,969 MMBtu/hr when not firing DBs.
- One NG-fired Auxiliary Boiler (EU59) rated at 95.52 MMBtu/hr (HHV),
- One pipeline fuel gas (dewpoint) heater (EU60) rated at 15.65 MMBtu/hr
- One 2.18 MW emergency generator with diesel-fired engine (EU61),
- One 422-bhp emergency use diesel-fired fire pump engine (EU62),
- One 10-cell mechanical draft cooling tower (EU63),
- One turbine circuit breaker with 30 lb. SF6 circuit (EU64),
- One lube oil system with demister vents (EU65),
- Two diesel storage tanks, 9,733-gallon vessel for emergency generator engine and 300-gallon vessel for the fire pump engine (EU66 and EU67),
- Additional NGCC paved haul roads and traffic (EU68),
- NG piping fugitives (EU69), and
- One 93% sulfuric acid tank (EU70).

A process flow diagram showing the proposed NGCC EGU Project operations is provided in **Appendix A**, and each of the air emission units is discussed in the following subsections.

2.3.1.1 NGCC Equipment Details

2.3.1.1.1 Unit 12

As illustrated in Figure A-2 in **Appendix A**, in a combined cycle process, ambient air is drawn into the compressor section of the GT through an inlet air filtration system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity (RH) to further enhance the overall production capability of the GT. After the evaporative cooler (EC) section, air enters the compressor section where it is compressed and channeled to the fuel/mix combustion section of the GT.

The compressor section of the GT, commonly referred to as the gas generator section, generates emissions from the fuel combustion process. A transition duct within the GT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator section combustion gases expand through the stages of the power turbine where the thermodynamic energy is converted to mechanical power. This mechanical power is then transmitted through the rotation of the shaft to the generator of the GT, which is directly coupled to the power turbine. The generator takes this rotational power and converts it to electricity.

[2] The equipment ratings listed are based on preliminary engineering designs.

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The hot combustion gases that are produced in the GT are directed into the HRSG through an exhaust transition duct where waste heat is captured and converted into steam energy before the exhaust gases exit the vertical stack. The HRSG duct contains the natural gas-fired DBs, which will be used at times to increase the temperature of the exhaust in the HRSG to enable the production of additional steam on an as-needed basis. This installation will primarily use DBs in the summer months and thus provide supplemental heat input capacity with the goal of ensuring the same MW generation as the winter months.

The steam produced in the HRSG is used in the ST to produce additional electrical power. Once mechanical work from the steam is captured, the steam is exhausted, and condensed in a vacuum within a condenser. The condensate is reused as feed water to the HRSG, creating a closed-loop system.

The proposed NGCC Unit is designed for continuous operations. The GT will be capable of operating between a nominal minimum emissions compliance load (MECL) and 100-percent load. MECL is defined as the minimum steady-state load at which the combustion turbine can operate at any given ambient condition and maintain compliance with all emission limits.

2.3.1.1.2 Air Pollution Controls

The CT will utilize dry-low-NO_X combustors (DLN) with LNBs in the HRSG. The NGCC Unit will utilize oxidation catalysts and SCR as add-on controls to reduce stack NO_X, CO, VOC, and organic HAP emissions. GHG emissions will be minimized through the use of a highly efficient combined cycle GT and HRSG unit, with combustion of low-carbon fuel (i.e., NG). A bank of drift eliminators will be installed after the evaporative cooling media to ensure that no water droplets or solids particles from water enter the GT. Therefore, there will be no contribution of PM emissions from the evaporative cooling systems to the generating units.

2.3.2 NG-Fired Auxiliary Boiler (EU59)

The NG-fired Auxiliary Boiler will be permitted with a maximum heat input capacity of 95.52 MMBtu/hr. The combustion system will utilize LNBs with FGR. The Auxiliary Boiler will only serve multiple steam users and will consist of the following:

- HRSG freeze protection (only required with the unit off-line in cold weather conditions)
- Unit starts under warm or cold start conditions. The Auxiliary Boiler steam will provide sparging steam to the HRSG and condenser as well as seal steam for the ST. After the combined cycle unit is up and running auxiliary steam is furnished by the HRSG (cold reheat) and the Auxiliary Boiler can be taken out of service.

Under the expected dispatch, the Auxiliary Boiler is only expected to operate at 25% utilization or less during periods of time where the NGCC Unit is active. However, KU is requesting that it be permitted to allow for a full load continuous operation schedule up to 4,000 hours per year to provide maximum operational flexibility.

2.3.3 Fuel Gas (Dewpoint) Heater (EU60)

One NG-fired fuel gas (dewpoint) heater with a maximum heat input of 15.65 MMBtu/hr will be used to heat the pipeline NG that will be introduced to the combustion turbine. The unit will utilize LNBs and will be capable of operating up to 8,760 hours per year.

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2.3.4 Emergency Generator and Firewater Pump with Diesel-Fired Engine (EU61 and EU62)

The project will employ a 2.18 MW emergency generator and a 422-bhp diesel-fired compression ignition engine for emergency purposes to supply energy to the fire pump. Ultra-low sulfur fuel oil (ULSFO) fuel with a maximum sulfur content of 0.0015 weight percent (or 15 ppm) will be used in the engines. Potential emissions are based on operating 500 hr/yr in accordance EPA guidance, although there are no hourly limits on an emergency engine when operating for emergency purposes.

2.3.5 Cooling Tower (EU63)

Steam exiting the ST will be condensed via indirect heat transfer using cooling water provided by a mechanical draft, ten-cell, back-to-back counter-flow wet cooling tower. Cooling tower drift will be minimized to 0.001% of the design recirculation rate or less using inherent drift eliminators.

2.3.6 Circuit Breaker (EU64)

One turbine circuit breaker will be installed to serve the NGCC project. The turbine circuit breaker will contain up to 30 lbs of SF6, with a maximum SF6 leak rate of 0.5%.

2.3.7 Lube Oil System with Demister Vents (EU65)

The GT and ST will be equipped with an internal lube oil storage and distribution system. A small quantity of the lube oil present in the system will be vaporized due to the high operating temperatures inside the turbine systems, potentially resulting in VOC emissions from the lube oil systems. The GT will be equipped with a demister system to avoid lube oil loss to the atmosphere to the extent possible; however, a small quantity of lube oil will be emitted, as VOC from the lube oil demister vents.

2.3.8 Diesel Storage Tanks (EU66 and EU67)

All diesel storage tanks for the NGCC project are designed to support emergency operations. The emergency generator engine will utilize a 3,733-gallon tank, while the fire pump engine will be equipped with a 300-gallon tank.

2.3.9 NGCC Haul Roads (EU68)

The operation of the new emission units constructed as part of the NGCC EGU Project will necessitate an increased amount of delivery truck traffic. New paved roads will be used to transport various chemicals throughout Brown Station. The paved routes will mitigate fugitive emissions. Since natural gas will be delivered via pipeline, no natural gas truck deliveries are estimated, further mitigating fugitives. Chemicals delivered include aqueous ammonia, cooling tower chemicals, and water treatment chemicals.

2.3.10 Natural Gas Piping Fugitives (EU69)

Brown Station will be constructing new components to connect to a NG pipeline to provide the requisite fuel to all NG-fired units to be installed as part of the project. The construction of the onsite portion of the NG pipeline will include the installation of various equipment leak components which will be sources of fugitive emissions (proposed EU69). These piping components are potential sources of carbon dioxide, methane and VOC.

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2.3.11 Sulfuric Acid Storage Tank (EU70)

KU will install one 12,200-gallon storage tank storing an aqueous solution of sulfuric acid. The aqueous solution will contain approximately 93% by weight sulfuric acid. The sulfuric acid solution will be used as a water treatment chemical. Brown Station will consume up to 146,400 gallons of this 93% sulfuric acid solution per year.

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3. EMISSIONS CALCULATION METHODOLOGIES AND SUMMARY

This section summarizes the emission calculation methodologies for the emission sources that comprise the proposed NGCC EGU Project. Within each emissions unit section, the methods used to calculate emissions are discussed, followed by a summary of the emissions estimates for the specific unit and, in the case of the CTs, the mode of operation. The annual potential emissions for regulated NSR pollutants and HAPs from the new units in the NGCC EGU Project are summarized in Section 3 of **Appendix B**. The hourly and annual potential emissions of all affected units are documented in the DEP7007 N Forms provided in **Appendix C**. These potential emissions are used as the basis for determining applicability of the project with respect to certain regulatory requirements, which is discussed subsequently in Sections 4 and 5. A detailed set of documented emission calculations is presented in **Appendix B** of this application for all the new emission units that are part of the NGCC EGU Project.

3.1 Combustion Turbine Emissions

3.1.1 Unit 12 NGCC (EU58)

The primary emissions units for the NGCC Project are the NG-fired GT and NG-fired duct burning within the HRSG. The following subsections present the maximum hourly emissions during steady-state operations and startup/shutdown (SU/SD) events, as well as the total annual emissions including SU/SD emissions.

3.1.1.1 GT Emissions from Steady State Operations

Normal or steady-state operation of a GT is characterized as continuous operation at loads generally in the 35 to 100% range (over the range at which emissions compliance is achieved). The GT may be operated at base load (100% operating load for the current ambient conditions) up to 8,760 hr/yr. As detailed in Section 4 of **Appendix B**, KU has calculated annual steady-state potential emissions based on 8,760 hr/yr firing NG.

Heat input to a gas turbine varies as a function of the fuel (type, composition, and quality), ambient temperature, RH, and evaporative cooler operation. As explained in more detail in Section 4 of **Appendix B**, each individual CT can achieve a maximum heat input capacity when firing NG of 4,525 MMBtu/hr (operating at 100% of base load with DBs, ambient temperature is 20 °F, and combustion air RH is 80%)

3.1.1.1.1 NO_X, CO, VOC, PM, SO_2, and H_2SO_4 Steady-State Emissions

As documented in Section 4 in **Appendix B**, maximum hourly controlled and uncontrolled emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SO_2, and H_2SO_4 for the proposed gas turbines rely on the vendor operational data and KU's vendor guarantee requirements for the GT unit, which are listed in Table 3-1 below. Emission factors for these pollutants were calculated as the maximum hourly emissions rate divided by the maximum fuel volumetric consumption.[3]

[3] As discussed above, KU has conservatively chosen the maximum fuel heat input on NG as a basis for fuel consumption in the PTE calculations. To develop site-specific emission factors relative to the volume of fuel consumption, KU has chosen a site-specific NG HHV of 1,053 Btu/scf.

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Table 3-1. GT – Basis of Pollutant Emissions Rates

Pollutant	NG Emissions Basis	Maximum Steady-State Emission Rate Fired (lb/hr)	Maximum Steady-State Emission Rate Unfired (lb/hr)
NO_X	2 ppm_{vd} (15% O_2)	34.0	31.8
CO	2 ppm_{vd} (15% O_2)	20.7	19.4
VOC	2/1 ppm_{vd} (15% O_2)	11.9	5.6
$PM/PM_{10}/PM_{2.5}$	0.5 gr S/100 scf with 100% conversion to $(NH_4)_2SO_4$	22.6	18.0
SO_2	0.5 gr S/100 scf	6.1	5.4
H_2SO_4	0.5 gr S/100 scf	5.4	4.8

Source: Maximum rate based on BACT

The GT will continue to comply with these emission rates irrespective of ambient weather conditions at all loads above MECL. Any emissions resulting from SU/SD operations are described in Section 3.1.1.2. Information regarding inherent and add-on controls used in the GT/HRSG system was provided in Section 2.3.1.1.

PM emissions include the formation of ammonium salts [e.g., $(NH_4)_2SO_4$]. Given the presence of the oxidation catalyst system, formation of condensable PM (CPM) and sub-micron filterable PM is possible under certain conditions. One pathway is the sulfate formation from H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$, as well as the nitrate formation in the form of NH_4NO_3. All PM is assumed to be less than 2.5 µm in mean diameter.

Annual emissions of SO_2 from NG firing were based on a maximum pipeline sulfur content and additional factors to account for chemical conversions. For SO_2, the emissions are based on an expected maximum sulfur content for the pipeline gas of 0.5 grains (gr)/100 standard cubic feet (scf) and 100% conversion from sulfur to SO_2. In reality, the total SO_2 emissions will be less due to the fact that some SO_2 further converts to SO_3, which can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. For simplicity, the potential emissions of SO_2 do not account for these further reductions and thus the emission estimates are conservative, due to the unknown fates of fuel-bound sulfur given the HRSG, SCR and oxidation catalysts as well as the changing ambient temperatures.

3.1.1.1.2 Ammonia Emissions

Ammonia emissions from the SCR have been calculated assuming the ammonia slip post-SCR is no more than 5 ppmvd at 15% O_2.

3.1.1.1.3 Formaldehyde and HAP Emissions

Controlled formaldehyde emissions from NG are calculated based on an emissions guarantee of 91 parts per billion by volume, dry (ppbvd) at 15% O_2, which is equivalent to the applicable standard in NESHAP Subpart YYYY, 40 CFR §63.6100. This concentration was then converted to a lb/MMBtu emission factor based on a default dry F-factor (Fd) for NG combustion from EPA Reference Method (RM) 19. The

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uncontrolled emissions factors for formaldehyde were obtained from Table 3.1-3 (for NG) and Table 3.1-4 (for FO) of the U.S. EPA's AP-42 Chapter 3, Section 3.1 *Stationary Gas Turbines*.[4]

The CT's uncontrolled emission factors for HAPs emitted (other than acetaldehyde) via NG combustion were also based on Tables 3.1-3 and 3.1-4 of AP-42. The background document supporting this chapter provided controlled emissions factors when using a CO catalyst for acetaldehyde, acrolein, and benzene.[5] For other organic HAPs, KU applied a nominal VOC control efficiency (CE) afforded by the oxidation catalyst. See Sections 4.3.3 and 4.4.4 of **Appendix B** for additional details and for the derivation of organic HAP control efficiencies.

3.1.1.1.4 GHG Emissions

GHG emissions are estimated based on proposed equipment specifications (i.e., maximum heat input) as provided by the vendor and the default emission factors in the U.S. EPA's Greenhouse Gas Reporting Program (40 CFR 98, Subpart C, Tables C-1 and C-2 for NG). According to 40 CFR §52.21(b)(49)(ii), GHG emissions for PSD applicability must show carbon dioxide equivalent (CO_2e) emissions calculated by multiplying the mass of each of the GHGs by its associated global warming potential (GWP), which are specified in Table A-1 to Subpart A of 40 CFR Part 98. The GWPs chosen for this PSD analysis are those required to be used for GHG reporting under 40 CFR Part 98 beginning January 1, 2025.[6]

3.1.1.2 GT Emissions from SU/SD Operations

The GT equipment package has its own unique features that allow the NGCC to quickly achieve emissions compliance during a cold, warm, or hot start event. The following provides the underlying basis for the total event estimates:

- Cold Start (CS) is preceded by over 72 hours of shutdown (or any warming events). The minimum value of 72 hours is assumed, which allows for a conservatively high number of CS per year.
  - Expected maximum annual CS events = **10** events/yr over a 73-280-minute ramp up time. KU used **73** minutes per CS for conservatism.

- Warm Start (WS) or "non-cold startup" is preceded by a shutdown (or any warming events) between 8 and 72 hours. The minimum value of **8** hours is assumed, which allows for a conservatively high number of WS per year.
  - Expected maximum annual WS events = **50** events/yr over a 63-to 89-minute ramp up time. KU used **63** minutes per WS for conservatism.

- Hot Start (HS) is defined as taking place within 0 to 8 hours of the previous shutdown without any warming provisions. No idling time was incorporated prior to a HS to allow for a conservatively high number of HS per year.
  - Expected maximum annual HS events =**125** events/yr over a 33- to 54-minute ramp up time. KU used **33** minutes per HS for conservatism.

- A SD occurs for 12 minutes and the total number is the sum of all CS, WS, and HS events. KU used **12** minutes per SD.

[4] https://www.epa.gov/sites/default/files/2020-10/documents/c03s01.pdf

[5] https://www.epa.gov/sites/default/files/2020-10/documents/b03s01.pdf

[6] 89 FR 31802, https://www.federalregister.gov/d/2024-07413

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- Expected maximum annual SD events = **185** events/yr over 12 to 21 minutes until emissions cease. KU used **12** minutes per SD for conservatism.

NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and CO_2 emissions during SU/SD events vary from steady state emissions; however, emissions of other pollutants do not vary substantively during these events (compared to those during normal steady-state operations). Therefore, only emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and CO_2 are separately defined for SU/SD events. The total emissions for each event are provided in Section 4.6 in **Appendix B**. KU is conservatively estimating the maximum number of each type of startup and shutdown event.

3.1.1.3 NGCC Simulations for Annual Emissions

The calculations in Section 4 of **Appendix B** detail the methodologies used to determine the annual PTE from the GT, DBs, and/or SU/SD events. The calculations presented therein are representative of one of a single GT with or without DB firing.

The following Process IDs have been assigned to the GT:

- Process ID 1: NG Combustion in GT (steady-state) and DB firing (herein called "fired" mode)
- Process ID 2: NG Combustion in GT (steady-state) (herein called "un-fired")
- Process IDs 3-6: GT Startup/Shutdowns events

Each of the Process IDs above have been considered in the methodologies used to determine the worst-case annual emissions from the NGCC. KU evaluated the following scenarios to determine a "worst-case" emissions profile:

- Scenario 1
  - 8,760 hr/yr GT steady-state in fired mode
  - No SU/SD events
- Scenario 2
  - 8,760 hr/yr GT steady-state in un-fired mode
  - No SU/SD events
- Scenario 3
  - 7,470 hr/yr NG steady-state
    - 7,470 hr/yr = 8,760 hr/yr – (10 CS events * 1.22 hr/CS + 50 WS events * 1.05 hr/WS + 125 HS events * 0.55 hr/HS + 185 SD events * 0.2 hr/SD) – (10 CS events * 72 hrs downtime + 50 WS events * 8 hrs downtime + 125 HS events * 0 hrs downtime + 185 SD events * 0 hrs downtime)
  - Worst-case emissions from SUSD events, with minimum amount of time per event and minimum downtime between events

Table 3-2 below summarizes the annual emissions for NSR-regulated air pollutants from each of the three scenarios outlined above for one turbine. Annual emissions of additional pollutants are summarized in Section 4.8 of **Appendix B**.

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Table 3-2. Annual Emissions from Each Scenario (tpy)

Pollutant	Scenario 1	Scenario 2	Scenario 3
NO_X	149.1	139.3	151.4
CO	90.8	84.8	134.6
VOC	52.0	24.3	64.6
$PM/PM_{10}/PM_{2.5}$	98.9	78.6	86.6
SO_2	26.9	23.6	23.0
H_2SO_4	23.7	20.8	20.3
Lead	8.97E-04	N/A	7.65E-04
CO_2e	2,289,968	2,008,979	1,952,638

For the detailed annual emissions derivations for each of the three scenarios outlined above, refer to Section 4 of **Appendix B**.

For all other pollutants besides those with hourly emission rates based on vendor-provided data, KU used the reference emission factors described in Section 3.1.1.1, converted the reference emission factors to a fuel volume-based emission factor as needed, and multiplied by the annual NG steady-state operating hours detailed above to arrive at a final annual PTE.

3.2 NGCC EGU Project Ancillary Equipment

There are several emissions units that are part of the NGCC EGU Project which support the operation of the GT. Descriptions of the emissions calculations for the ancillary equipment are provided in the following subsections.

3.2.1 Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60)

Potential emissions from the Auxiliary Boiler and fuel gas (dewpoint) heaters are estimated based on KU's vendor requirements, pipeline NG specifications, and published AP-42 emissions factors. Annual potential emissions for the Auxiliary Boiler and fuel gas (dewpoint) heater are documented in Sections 5.4 and 6.3 of **Appendix B**.

3.2.2 Emergency Use Diesel-Fired Engines (EU61 and EU62)

The emergency diesel-fired engine for the emergency generator (EU61) and the emergency diesel-driven fire water pump engine (EU62) will meet the emissions requirements specified in Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII). Emissions of regulated NSR pollutants from the engines are based on either 40 CFR Part 60, Subpart IIII emissions limits – which points to U.S. EPA Tier 2 emissions limits for the generator and NSPS IIII Table 4 for the fire pump engine – or AP-42 emissions factors for criteria pollutants and HAPs.

Annual potential emissions based on these methodologies for the emergency generator are shown in Section 7.3 and annual potential emissions for the emergency fire water pump engine are shown in Section

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8.3 in **Appendix B**. Consistent with past KDAQ permitting practice, the PTE from these emergency-use engines is based on 500 hours per year of operation.[7]

3.2.3 Cooling Tower (EU63)

The 10-cell cooling tower to be installed as part of the NGCC EGU Project will be a source of PM emissions. As the water flows down through a cooling tower, the draft air picks up water droplets that can be emitted from the top of the tower (i.e., "drift loss"). Drift loss is minimized through the use of mist eliminators. PM emissions can result due to the presence of dissolved solids in the cooling tower water droplets that are released from the tower. As the cooling tower droplets disperse in the atmosphere, the liquid water evaporates, leaving behind solid particles in the form of PM.

The annual PTE of PM from the cooling tower has been estimated as a function of cooling water recirculation rate, drift loss, and TDS concentration in the recirculating water. The planned specifications for the new cooling tower require a cooling water recirculation rate of 95,000 gallons per minute (gpm), a drift loss rate through the mist eliminators of 0.001%, and a TDS concentration of 990 ppm.

Using these parameters, an aerodynamic particle size distribution was derived according to the methodologies presented in "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie.[8] The linear interpolation calculations used to develop the particle size distribution are outlined in Section 9.2 of **Appendix B**. This methodology derives scaling factors equal to the percentage of particles less than a target aerodynamic particle diameter to be applied to the filterable PM emission factor developed based on the parameters specified above.

The emission factors for PM, PM_{10}, and $PM_{2.5}$ developed using the methodologies above are summarized in Section 9.2.3 of **Appendix B**, and the annual PTE of the new cooling tower is summarized in Section 9.3 of **Appendix B.**

3.2.4 Circuit Breaker (EU64)

The circuit breaker may occasionally leak SF_6 to the atmosphere, where the pollutant acts as a greenhouse gas. Annual CO_2e emissions from the leaking of SF_6 from the circuit breaker have been calculated assuming a 0.5% leak rate per year[9] and a GWP of 23,500.

3.2.5 Lube Oil System (EU65)

A potential source of VOC emissions is the lube oil system used for the GT and ST. The GT and the ST will include a lubricating oil sump with a system capacity of approximately 10,000 gallons. The GT and ST will also be equipped with lubricating oil vents, which include electrostatic precipitators/demisters for lubricating oil mist control. Use of low-volatility/low-VOC oil and a low consumption rate of lubricating oil in the GT and ST will result in insignificant/negligible VOC emissions from storage of the lubricating oils. The working losses conservatively assume that all lube oil consumed/replaced will evaporate and contribute to VOC

[7] In a memo from EPA Air Quality and Planning Standards Director John S. Seitz to the regional directors of Air and Radiation, "Calculating Potential to Emit (PTE) for Emergency Generators", dated September 6, 1995, EPA formalized its position that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.

[8] "Calculating Realistic PM_{10} Emissions from Cooling Towers," Joe Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2 (April 20, 2004).

[9] 0.5% leak rate is BACT.

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emissions. Annual potential VOC emissions from the lube oil demister vents are shown in Section 11.2 of **Appendix B**.

3.2.6 Storage Tanks (EU66, EU67 and EU70)

All fuel storage tanks are considered sources of VOC emissions. Standing and working losses of VOCs were calculated for all storage tanks using TankESP®, which calculates working and breathing losses using the most current version of AP-42 Section 7.1. – *Organic Liquid Storage Tanks*.[10] Annual potential VOC emissions from the two FO storage tanks serving the emergency generator engine and fire water pump engine belly tanks are documented in Section 12.2.

In addition to the AP-42 Section 7.1 methodologies used by TankESP, stock properties for the 93% sulfuric acid solution have been calculated using interpolated partial pressure data from Perry's Chemical Engineer's Handbook (8th Edition) for the vapor species at the specified H_2SO_4 concentration. Annual potential H_2SO_4 emissions from the 93% sulfuric acid storage tank are documented Section 15.2 of **Appendix B**.

3.2.7 New Haul Roads (EU68)

Fugitive PM emissions potentially caused due to the increased vehicle traffic and altered roadways resulting from the need to deliver various chemicals and fuel for the new NGCC EGU project have been estimated using the methodologies of AP-42, Section 13.2.1 for Paved Roads. KU will use existing paved roadways throughout the plant and pave new roadways to accommodate the increased vehicle traffic. KU anticipates truck traffic for the delivery of the following:

- Aqueous ammonia;
- Cooling tower chemicals; and
- Water treatment chemicals.

Each of the deliveries corresponds to a discrete truck route. The average truck weight per truck route was calculated based on the expected usage of each chemical, truck refill capacity, and assumed empty truck weights. The total VMT per delivery truck route were measured based on conceptual drawings of the final paved roads post-project. The VMT-weighted average truck weight and total VMTs per truck route are summarized in Section 13 of **Appendix B**.

The PM, PM_{10}, and $PM_{2.5}$ emission factors were developed based upon Equation 1 in AP-42, Section 13.2.1:

$E = k(sL)^{0.91}(W)^{1.02}$
E = emission factor (lb/VMT)
k = particle size multiplier
sL = road surface silt content (g/m^2)
W = average vehicle weight (tons)

After deriving the emission factors for each of the four truck routes, an annual PTE was calculated by multiplying the emission factors by the calculated annual VMTs per delivery truck type. This emissions calculation methodology is further detailed in Section 13 of **Appendix B**.

[10] https://www.trinityconsultants.com/software/tanks/tankesp

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3.2.8 Natural Gas Piping Fugitives (EU69)

Section 14 of **Appendix B** details the emission calculation methodology used to estimate the annual PTE of VOC and CO_2e from leaks in the new NG piping components to be installed as part of the NGCC EGU Project. The new equipment leak components to be installed include valves, relief valves, flanges, vents, compressors, and sampling connections.

KU used emission factors published in EPA's "Protocol for Equipment Leak Emissions Estimates"[11] to calculate the annual VOC and CO_2e PTE from each type of component. The emission factors chosen are representative of oil and gas production operations and as such are appropriate to use for estimating NG transmission fugitive emissions. The emission factors for valves and flanges in gas service from Table 2-4 in EPA's Protocol were used for all valves and flanges to be installed. For the sampling connections and relief valves, KU used the emission factors for "Other" components in gas service. Per footnote c to Table 2-4 in EPA's Protocol, the "Other" equipment type was derived from "compressors, diaphragms, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents." As such, it is appropriate to apply the emission factor for the "Other" category to the sampling connections, relief valves, vents, and compressors.

The emission factors are representative of the total mass of leaking NG per hour per component (i.e., kg/hr/component). This emission factor can be applied to the emissions of either VOC or CO_2e by multiplying by an appropriate weight fraction. For pipeline quality NG, KU has estimated that the NG stream transmitted to the plant will contain approximately 84.7% by weight methane, 3.69% by weight CO_2, and 0.38% by weight VOC. Applying these weight fractions to the emission factors from EPA's Protocol, a set of VOC, CO_2, and methane emission factors were developed for each component type. Multiplying by the number of components and assuming 8,760 hr/yr of operation, the annual PTE of VOC and CO_2e was calculated as shown in Section 14.4 of **Appendix B**.

[11] Protocol for Equipment Leak Emissions Estimates (Document EPA-453/R-95/017, November 1995)

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4. NSR APPLICABILITY ASSESSMENT

This section addresses the methodology used to quantify the emissions increase from the proposed NGCC EGU Project and assesses applicability of the NSR permitting regulations.

4.1 PSD/Nonattainment NSR Applicability Background

The NSR program was designed to protect public health and welfare from the effects of air pollution and to preserve and/or improve air quality throughout the nation. The NSR program requires certain stationary sources of air pollution to obtain air pollution permits prior to beginning construction. Construction of new sources with emissions above statutory thresholds, and modifications of existing sources emitting above those thresholds or that increase emissions of regulated NSR pollutants by more than the major modification thresholds specified in the NSR regulations are subject to NSR permitting requirements.

The major source NSR regulations encompass two distinct programs that each have unique requirements for new or modified sources. The applicability of these two programs depends on the area's attainment status with respect to the NAAQS. The PSD program, based on requirements in Part C of Title I of the Clean Air Act (CAA), applies to pollutants for which the area is not exceeding the NAAQS (areas designated as attainment or unclassifiable) and to regulated NSR pollutants for which there are no NAAQS. The nonattainment NSR (NNSR) program, based on Part D of Title I of the CAA, applies to pollutants for which the area is not meeting the NAAQS (areas designated as nonattainment).

Brown Station is located in Mercer County, Kentucky, which has been designated by the U.S. EPA as an unclassified/attainment area for all criteria pollutants.[12] As such, only PSD permitting requirements are potentially applicable to the proposed project

4.2 PSD Program Source Classification

Kentucky has incorporated the requirements of the PSD permitting program into its SIP at 401 KAR 51:017.[13]

The PSD requirements apply to the construction of a new *major stationary source* (as defined in 401 KAR 51:001, Section 1(118)) **or** any project at an existing major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42 U.S.C. 7407 (d)(1)(A)(ii) and (iii) that is a major modification.

A stationary source is a major source if the PTE for a specific pollutant equals or exceeds the major source threshold for *regulated NSR pollutants*.[14] The regulated NSR pollutants of relevance for the types of emission units covered by the proposed project are NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, lead, and H_2SO_4 mists.

For projects involving increases in GHG emissions, the mechanism for triggering PSD review is different from other regulated NSR pollutants. For a project to trigger PSD review for GHGs, GHGs must first become

[12] https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-81/subpart-C/section-81.318 and https://www3.epa.gov/airquality/greenbook/anayo_ky.html

[13] 40 CFR 51.166(a)(1)

[14] *Regulated NSR Pollutant* defined in 401 KAR 51:001, Section 1(207)

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subject to regulation to be treated as a regulated NSR pollutant that can fall under the PSD requirements.[15] A physical change or change in the method of operation at a facility that results in an emissions increase of a non-GHG pollutant exceeding the significance thresholds **and** an emissions increase of GHG exceeding 75,000 tpy CO_2e (for the project alone and on a net basis considering contemporaneous emissions increases and decreases) would make the GHG emissions increase from the project subject to regulation and would require PSD review for the GHG emissions from the new units associated with the proposed project.[16]

The threshold for defining a facility as a major stationary source under the PSD permitting program is 250 tpy of any regulated NSR pollutant unless the facility belongs to one of 28 specially named source categories (List of 28), in which case the major stationary source threshold is 100 tpy.[17,18] Existing operations at Brown Station, classified under SIC Code 4911, "Electric Services", include "fossil fuel-fired steam electric plants," which is a named category on the List of 28. As such, the major source threshold for the PSD program is 100 tpy. The potential emissions of at least one regulated NSR pollutant currently exceeds 100 tpy; therefore, Brown Station is classified as an existing major stationary source under the PSD program.

4.3 PSD Applicability Analysis Methodology

4.3.1 Defining the Project

The proposed NGCC EGU Project involves the installation and operation of the new NGCC system and the addition of ancillary sources in support of these operations.

4.3.2 Existing versus New Emission Units

For purposes of calculating project-related emissions increases (labeled herein as project emissions increase or PEI), different calculation methodologies are used for existing and new units; therefore, it is important to clarify whether a source affected by the combined project is considered a new or existing emission unit.

401 KAR 51:001, Section 1(64) defines *emission units* as any part of a stationary source that emits or would have the PTE any regulated NSR pollutant and includes an electric utility steam generating unit (EUSGU). For purposes of this section, there are two types of emissions units:

> *(a) A **new emissions unit** is any emissions unit that is (or will be) newly constructed and that has existed for less than 2 years from the date such emissions unit first operated.*
>
> *(b) An **existing emissions unit** is any emissions unit that does not meet the requirements in paragraph (a) of this subsection or is a replacement unit.*

[15] *Subject to regulation* is defined in 401 KAR 51:001, Section 1(231), which cross-references the federal definition in 40 CFR 51.166(b)(48).

[16] The component of the "subject to regulation" definition relating to the 100,000 tpy CO_2e major source threshold was recently revoked by the U.S. Supreme Court in Utility Air Regulatory Group (UARG) v. Environmental Protection Agency (EPA) (No. 12-1146) ruling.

[17] 401 KAR 51:001, Section 1(118)

[18] Being a List of 28 source says nothing about whether a facility is classified as a minor or major source under PSD or whether it is subject to PSD permitting requirements. Being on the List of 28 imparts no particular regulatory requirements or permitting obligations. It only defines what the major source threshold is for a facility in an attainment area.

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All emissions units associated with the project are considered new emissions units. There are no existing emissions units being modified or affected by the project.

4.3.3 Two-Step Major Modification Determination Process

As Brown Station is classified as an existing major stationary source for PSD, if the proposed project meets the definition of a *major modification* (specific to each regulated NSR pollutant), then the full PSD permitting requirements apply for that pollutant. *Major modification* is defined at 401 KAR 51:001, Section 1(114):

> *"Major Modification"* means any physical change in or change in the method of operation of a major stationary source that would result in a significant emission increase [Step 1] and a significant net emissions increase of a regulated NSR pollutant [Step 2] … [Step 1 & Step 2 added]

Certain exemptions to the major modification definition exist that, if applicable, means a project does not require an emission increase assessment. The NGCC EGU Project does not qualify for any of the established exemptions.

Pursuant to 401 KAR 51:001, Section 1(219), *significant emissions increase* means, for a regulated NSR pollutant, an increase in emissions that is *significant* (as defined in 401 KAR 51:001, Section 1(218)) for that pollutant. For those pollutants with *significant emission increases*, the net creditable emission increases and decreases over the contemporaneous period (as defined in 401 KAR 51:001, Section 1(144)(c)) are estimated and the *net emissions increase* is calculated for comparison with the *significant* thresholds (as defined in 401 KAR 51:001, Section 1(218)).

Net emissions increase (NEI) is defined by 401 KAR 51:001, Section 1(144) as:

> *"Net Emissions Increase"* means, with respect to any regulated NSR pollutant … the amount by which the sum of the following exceeds zero:
>
> (i) *The increase in emissions … as calculated pursuant to* 401 KAR 51:017, Section 1(4). [for existing units, calculated by actual-to-projected actual [19] or actual-to-potential; for new units, calculated by actual-to-potential] [20, 21]
>
> (ii) *A*ny other increases and decreases in actual emissions…that are contemporaneous with the particular change and are otherwise creditable. Baseline emissions for calculating increases and decreases…shall be determined as provided…

[19] 401 KAR 51:017, Section 1(4)(a)1., Actual-to-projected-actual applicability test for projects that only involve existing emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

[20] 401 KAR 51:017, Section 1(4)(a)2., Actual-to-potential test for projects that only involve construction of new emissions units, states: A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit … and the baseline actual emissions … equals or exceeds the significant amount for that pollutant …

[21] 401 KAR 51:017, Section 1(4)(a)3., *Hybrid test for projects that involve multiple types of emission units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the methods specified in subparagraphs 1 and 2 of this paragraph as applicable … equals or exceeds the significant amount for that pollutant …*

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Step 1 is commonly referred to as the "project emission increases (PEI)" analysis as it accounts only for emissions related to the proposed project itself. If the emission increases estimated per Step 1 exceed the major modification thresholds, then the applicant may move to Step 2, commonly referred to as the 5-year netting analysis. The netting analysis includes all projects in the contemporaneous period for which a creditable emission increases or decreases occurred. If the resulting net emission increases exceed the major modification threshold, then NSR permitting requirements apply.

4.4 Components of Project Emission Increases

To calculate the PEI, the difference between a future emission level (either potential emissions or projected-actual-emissions) and the BAE must each be calculated. For new emission units, future emissions are based on the future annual potential emission rate of the unit considering inherent physical and operational constraints on the production capacity of the equipment and federally enforceable emissions/operating limitations, where applicable. Baseline actual emissions for new emission units are zero.

As stated previously, there are no existing emission units being modified or affected by the project.

4.5 Project Emission Increase Evaluation

As stated above, the proposed project involves only new emissions units. The procedure for calculating whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified. Pursuant to 401 KAR 51:017, Section 1(4)(a)(2),

> *(2)* **Actual-to-potential test for projects that involve only construction of new emissions units.** A significant emissions increase of a regulated NSR pollutant shall be projected to occur if the sum of the potential to emit from each new emissions unit following completion of the project equals or exceeds the significant amount for that pollutant.

Fugitive emissions are included in the annual emissions total for the PSD applicability determination since the facility is included in a source category specifically defined in 401 KAR 51:017 Section 7(1)(c).

For the PSD permitting program, "potential to emit (PTE)" is defined as the "maximum capacity of a stationary source to emit a pollutant under its physical or operational design."[22] Based on these considerations, annual potential emissions are calculated for each new emission unit based on representative emission factors for each unit type and used in the PSD applicability analysis.

4.6 Contemporaneous Netting Analysis

PSD regulations allow the calculation of creditable emission increases and decreases over a contemporaneous period for each pollutant for which a significant emissions increase will occur as a result of the project. There were no projects within the 5-year contemporaneous period at the Brown Plant which resulted in an emissions increase of any NSR-regulated air pollutants.

4.7 PSD Applicability Summary

For each relevant regulated NSR pollutant, Table 4-1 lists the PSD SER for comparison against the PEI from Step 1 of the PSD applicability analysis.

[22] 401 KAR 51:001, Section 1(190)(b)

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Table 4-1. NGCC EGU Project Emissions Increases Compared with PSD Significant Emission Rates

Pollutant	"Step 1" Project Emissions Increase (tpy)	PSD Significant Emission Rate[a] (tpy)	Project Triggers PSD Review? (Yes/No)
PM	**102.0**	25	Yes
PM_{10}	**101.7**	15	Yes
$PM_{2.5}$	**100.7**	10	Yes
NO_X	**169.2**	40	Yes
CO	**148.9**	100	Yes
VOC	**67.2**	40	Yes
SO_2	27.2	40	No
H_2SO_4	**23.7**	7	Yes
Lead	0.001	0.6	No
GHGs (as CO_2e)	**2,321,537**	75,000 [b]	Yes

a. 401 KAR 51:001, Section 1(218)(a) and (231).
b. For a project that causes a 75,000 tpy increase in CO_2e emissions and an increase above the SER for a non-GHG pollutant, GHGs become subject to regulation and are treated as a regulated NSR pollutant with a PSD SER of 0 tpy.

The Step 1 project emissions increase for lead and SO_2 will be less than their respective SERs. The Step 1 PEI for PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4 mists, and GHG exceed the SERs. Since there are no contemporaneous netting credits associated with these pollutants, PSD review under Sections 8 to 16 of 401 KAR 51:017 is required.

A detailed table documenting the potential emissions from new emission units is provided in Section 2 of **Appendix B**.

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5. APPLICABLE FEDERAL AND STATE REQUIREMENTS

Emission units constructed as part of the proposed NGCC EGU Project will be subject to certain federal and Kentucky air quality regulations. This section of the application summarizes the air permitting requirements and the key air quality regulations that will apply to emission units constructed or modified as part of these projects. Specifically, applicability to NSPS, pollutant- and category-specific NESHAP, Compliance Assurance Monitoring (CAM), Title V operating permit regulations, Acid Rain Program (ARP), Clean Air Interstate Rule (CAIR)/Cross-State Air Pollution Rule (CSAPR), and Kentucky SIP-specific regulations are addressed.

In **Appendix C**, the DEP7007 V Form identifies regulatory requirements for emission units cited below. As an optional supplement to the application, to assist in the Division's review of the application and development of an amended Title V permit, an edited version of the existing Title V permit for Brown Generating Station showing new and modified permit revisions that would encompass the proposed project is provided in **Appendix F**.

5.1 New Source Performance Standards

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA to establish federal emissions standards for source categories that cause or contribute significantly to air pollution. EPA is required to establish standards based on the best systems of emission reductions from technologies that have been adequately demonstrated, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in 40 CFR 60.

Any source subject to an NSPS is also subject to the general provisions of NSPS Subpart A, except as noted. A review of all NSPS that could potentially be applicable to any of the new emission units associated with the project is presented in this section. The list of category-specific NSPS that will apply to the affected emission units are as follows:

- 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units – Applies to the Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60)
- 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines – Applies to GT (EU58)
- 40 CFR 60 Subpart TTTTa – Standards of Performance for GHG Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units – Applies to GT (EU58)
- 40 CFR 60 Subpart IIII – Stationary Compression Ignition Combustion Engines – Applies to the 2.18 MW Diesel Emergency Generator Engine (EU61) and the Fire Pump Engine (EU62)

5.1.1 NSPS Subpart A – General Provisions (Applicable)

All affected sources subject to source-specific NSPS are subject to the general provisions of NSPS Subpart A unless specifically excluded by the source-specific NSPS. Subpart A requires initial notification, performance testing, recordkeeping and monitoring, provides reference methods (RMs), and mandates general control device requirements for all other subparts as applicable.

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5.1.2 NSPS Subpart D – Fossil Fuel-Fired Steam Generators > 250 MMBtu/hr (Not Applicable)

40 CFR 60 *Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators* (NSPS D), applies to fossil fuel-fired steam generating units with heat input capacities greater than 250 MMBtu/hr that have been constructed or modified since August 17, 1971.[23] The rule defines a fossil fuel-fired steam generating unit as:[24]

> *A furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.*

The GT and HRSG with NG-fired DBs (EU58) will not be subject to NSPS D because:

- The GT is not classified as a steam generating unit under this regulation and
- The HRSG with NG-fired DBs will be subject to NSPS Subpart KKKK instead and as such, are not subject to NSPS D.[25]

The Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60) are each implicitly not subject since their heat input capacity is less than 250 MMBtu/hr.

5.1.3 NSPS Subpart Da – Electric Utility Steam Generating Units > 250 MMBtu/hr (Not Applicable)

40 CFR *Subpart Da – Standards of Performance for Electric Utility Steam Generating Units* (NSPS Da), provides standards of performance for electric utility steam generating units with heat input capacities greater than 250 MMBtu/hr of fossil fuel (alone or in combination with any other fuel) for which construction, modification, or reconstruction commenced after September 18, 1978.[26] The term "steam generating unit" is defined under this regulation as:[27]

> *For units constructed, reconstructed, or modified after May 3, 2011, steam generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines…*

The GT and HRSG with NG-fired DBs (EU58) will not be subject to NSPS Subpart Da because:

- The GT is not classified as a steam generating unit under this regulation and
- The HRSG with NG-fired DBs will be subject to NSPS Subpart KKKK instead and as such, are not subject to NSPS Subpart Da.[28]

The Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60) are each implicitly not subject since their heat input capacity is less than 250 MMBtu/hr.

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[23] 40 CFR §60.40

[24] 40 CFR §60.41

[25] 40 CFR §60.40(e)

[26] 40 CFR §60.40Da(a)

[27] 40 CFR §60.41Da

[28] 40 CFR §60.40Da(e)

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5.1.4 NSPS Subpart Db – Steam Generating Units > 100 MMBtu/hr (Not Applicable)

40 CFR 60 *Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units* (NSPS Db), provides standards of performance for steam generating units with capacities greater than 100 MMBtu/hr for which construction, modification, or reconstruction commenced after June 19, 1984.[29] The term "steam generating unit" is defined under this regulation as:[30]

> *Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. This term includes anymunicipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.*

The GT and HRSG with NG-fired DBs (EU58) will not be subject to NSPS Subpart Db, because:

- The GT is not classified as a steam generating unit under this regulation and
- HRSGs with NG-fired DBs will be subject to NSPS Subpart KKKK instead and as such, are not subject to NSPS Subpart Db.[31]

The Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60) are each implicitly not subject to NSPS Db since their heat input capacity does not exceed 100 MMBtu/hr.

5.1.5 NSPS Subpart Dc – Small Steam Generating Units (Applicable)

40 CFR 60 *Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* (NSPS Dc), provides standards of performance for each steam generating unit for which construction, modification, or reconstruction commenced after June 9, 1989, and for which the maximum design heat input capacity is 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.[32] The term "steam generating unit" is defined under this regulation as:[33]

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

The GT and HRSG with NG-fired DBs (EU58) is not be subject to NSPS Subpart Dc because its heat capacity is well above the applicability threshold.

However, both the new NG-fired Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60), meet the definition of a steam generating unit and fall within the applicable heat input capacity range, and each is an

[29] 40 CFR §60.40b(a)

[30] 40 CFR §60.41b

[31] 40 CFR §60.40b(i)

[32] 40 CFR §60.40c(a)

[33] 40 CFR §60.41c

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affected facility after the applicability date.[34] Units subject to NSPS Subpart Dc that fire natural gas do not have to meet any applicable emission limits, testing, or monitoring requirements under this subpart, except for the requirement to monitor natural gas consumption on a monthly basis. Initial notifications of the dates of construction commencement, anticipated startup, actual startup, in addition to the design heat input capacity and the identification of fuels to be combusted must be submitted to the Division.

5.1.6 NSPS Subpart Kc – Volatile Organic Liquid Storage Vessels (Not Applicable)

40 CFR 60 Subpart Kc applies to each storage vessel with a capacity greater than or equal to 20,000 gallons that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after October 4, 2023. NSPS Subpart Kc defines "storage vessel" and "volatile organic liquids" as follows:

> *Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include 1) frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors; 2) subsurface caverns or porous rock reservoirs; or 3) process tanks.*
>
> *Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.*

The emergency generator storage tank (EU66) and fire pump engine belly tank (EU67) have capacities below the applicability threshold and are therefore not subject to NSPS Subpart Kc.

5.1.7 NSPS Subpart GG – Stationary Gas Turbines (Not Applicable)

40 CFR 60 *Subpart GG – Standards of Performance for Stationary Gas Turbines* (NSPS GG), applies to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the LHV of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[35]

The GT and HRSG with NG-fired DBs (EU58) will be a stationary gas turbine with a heat input above the threshold and constructed after the applicability date. However, pursuant to 40 CFR §60.4305(b), stationary combustion turbines regulated under NSPS KKKK are exempt from the requirements of NSPS GG. Therefore, NSPS GG does not apply.

5.1.8 NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines (Applicable)

40 CFR 60 *Subpart IIII - Standards of Performance for Stationary Compressions Ignition Internal Combustion Engines* (NSPS IIII) applies to owners or operators of stationary compression ignition (CI) internal combustion engines (ICE) manufactured after April 1, 2006 that are not fire pump engines, and fire pump engines manufactured after July 1, 2006 that commence construction after July 11, 2005.

[34] The Fuel Gas (Dewpoint) Heater is equipped with a water/glycol bath (i.e., the heat transfer medium) that indirectly heats the pipeline gas stream, which makes it subject to NSPS Dc.

[35] 40 CFR §60.330

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5.1.8.1 Emergency Generator (EU61)

The NGCC Project is provisioned to have a 2.18 MW rated emergency generator. Since the emergency diesel fired engine (approximately 2,923 bhp) serving the generator will be used for emergency purposes and cylinder displacement is less than 10 liters/cylinder, the engine will be subject to the emission limits in 40 CFR §§60.4205(b) and 60.4202(a)(2) and the fuel specifications of 40 CFR §60.4207.

Per 40 CFR §60.4205(b),

> *(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.*

Per 40 CFR §60.4202(a)(2),

> *(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.*
>
> > *(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.*

Starting with Model Year 2006, a new engine with a rated power greater than or equal to 130 kW but less than or equal to 560 kW, must meet the Tier 3 standard in Table 3 to Appendix I as specified in 40 CFR Part 1039. As the emergency generator's rated power output will be greater than 560 kW, it must meet the Tier 2 standards in Table 2 to Appendix I.[36]

Table 2 to Appendix I - Tier 2 Emission Standards contain the following applicable emission limits for model year 2006 or later units with rated power outputs greater than 560 kW:

- 6.4 grams per kilowatt hour (g/kW-hr) (equivalent to 4.8 g/hp-hr) of NMHC+ NO_X,
- 3.5 g/kW-hr (equivalent to 2.6 g/hp-hr) of CO, and
- 0.20 g/kW-hr (equivalent to 0.15 g/hp-hr) of PM.

Additionally, pursuant to 40 CFR §1039.105(b)(1) through (3), smoke from the engine may not exceed the following standards.

1. 20 percent during acceleration mode;
2. 15 percent during lugging mode; and
3. 50 percent during peaks in either the acceleration or lugging mode.

[36] https://www.ecfr.gov/current/title-40/part-1039#Appendix-I-to-Part-1039

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As provided in 40 CFR §60.4211(c), to demonstrate compliance with these emission standards, KU will purchase an emergency generator certified to the emission limits listed 40 CFR §60.4205(b) or more stringent, and will install and configure the engine according to the manufacturer's specifications. No performance testing is required.

KU will use diesel fuel that meets the requirements of 40 CFR §1090.305 for nonroad diesel fuel in accordance with 40 CFR §60.4207(b). This regulation states that the sulfur content must remain less than or equal to 15 ppm, and either the cetane index must be at least 40, or the aromatic content must be less than or equal to 35 volume percent.

Under NSPS IIII, KU will monitor hours of operation of the emergency generators using non-resettable hour meters and records per 40 CFR §60.4214(b) will be maintained. No other monitoring is required.

5.1.8.2 Emergency Fire Pump Engine (EU62)

The NGCC EGU Project is provisioned to have a nominal 422 hp fire pump engine that will combust ULSFO. The date of manufacture for the emergency fire pump engine and date of construction will occur after the dates specified above; therefore, the emergency fire pump engine will be subject to the provisions of NSPS IIII.

Since the proposed emergency fire pump engine will have a power rating of 422 hp and a displacement of less than 30 liters per cylinder, the emergency fire pump engine must comply with the emission standards in Table 4 of NSPS IIII for all pollutants [§60.4205(c)]. Specifically, the emergency fire pump engine must meet the following emissions standards for non-methane HC (NMHC)+NO_X and PM:[37]

- 3.0 grams per horsepower-hour (g/hp-hr) of NMHC+NO_X,
- 2.6 g/hp-hr for CO, and
- 0.15 g/hp-hr of PM.

As documented in the emissions calculations provided in Section 8 of **Appendix B**, the proposed emergency fire pump engine will meet these emissions limits.

As provided in 40 CFR §60.4211(c), to demonstrate compliance with these emission standards, KU will purchase an emergency fire pump engine certified to the emission limits listed in Table 4 of NSPS IIII or more stringent, and will install and configure the engine according to the manufacturer's specifications. No performance testing is required.

Effective October 1, 2010, only diesel fuel that meets the requirements set forth in 40 CFR §1090.305 may be used in accordance with 40 CFR §60.4207(b). This regulation states that the sulfur content must remain less than or equal to 15 ppm, and either the cetane index must be at least 40, or the aromatic content must be less than or equal to 35 volume percent.

Under NSPS IIII, KU will monitor the emergency fire pump engine hours of operation using a non-resettable hour meter and records per §60.4214(b) will be maintained. No other monitoring is required.

[37] NSPS IIII does not establish CO emission limits for fire pump engines manufactured after 2008 for engines at this size.

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5.1.9 NSPS Subpart KKKK – Stationary Combustion Turbines (Applicable)

40 CFR 60 *Subpart KKKK – Standards of Performance for Stationary Combustion Turbines* (NSPS KKKK) establishes emissions limits for a combustion turbine and associated HRSG that commenced construction, modification, or reconstruction after February 18, 2005, and have a heat input from the GT at peak load equal to greater than 10.7 gigajoules (10 MMBtu/hr) based on the HHV of the fuel. HRSGs with DBs regulated under NSPS KKKK are exempt from the requirements of NSPS D, Da, Db, and Dc. Also, because the GT is subject to NSPS KKKK, it is exempt from NSPS GG.

The affected facility under NSPS KKKK is a stationary combustion turbine, which is defined by 40 CFR §60.4420 as follows:

> *All equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and subcomponents comprising any simple cycle stationary combustion turbine, any regenerative/ recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability.*

The GT and HRSG with NG-fired DBs (EU58) will be a combustion turbine with a heat input above the threshold and constructed after the applicability date and thus will be subject to NSPS KKKK. NSPS KKKK specifies emissions limitations, monitoring, reporting, and recordkeeping requirements for NO_X and SO_2.

5.1.9.1 Emissions Limits

For a new combustion turbine firing NG with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2 or 0.43 lb/ MWh gross energy output.[38] For units greater than 30 MW, NSPS KKKK also includes a NO_X limit of 96 ppm at 15% O_2 or 4.7 lb/MWh gross output for turbine operation at ambient temperatures less than 0°F and turbine operation at loads less than 75% of peak load.[39] Compliance with the NO_X emission limit is determined on a 30-unit operating day rolling average basis.[40]

SO_2 emissions into the atmosphere from combustion turbines located in the continental U.S. are limited to 0.9 lb/MWh gross output [or 110 nanograms per Joule (ng/J)], **or** the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.[41]

As documented in detail in Section 4 of Appendix B, KU's NGCC will have NO_X and SO_2 emissions well below the NSPS KKKK emissions standards and will comply with the applicable monitoring, reporting, and performance test requirements of NSPS KKKK.

5.1.9.2 Monitoring and Testing Requirements

Pursuant to 40 CFR §60.4333(a), the GT, air pollution control equipment, and monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions.

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[38] 40 CFR §60.4320(a) and Table 1

[39] Ibid.

[40] 40 CFR §60.4350(h), 40 CFR §60.4380(b)(1)

[41] 40 CFR §60.4330(a)(1) or (a)(2), respectively

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This requirement applies at all times including during startup, shutdown, and malfunction. Additional emissions limit-specific compliance demonstration requirements are detailed in the following subsections.

5.1.9.2.1 NO_X Compliance Demonstration Requirements

The GT will not use either water or steam injection; therefore, the continuous compliance requirements at 40 CFR §60.4340 apply. Pursuant to 40 CFR §60.4340(b)(1), KU will install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) as described in 40 CFR §§ 60.4335(b) and 60.4345. KU will certify according to 40 CFR Part 75 Appendix A to demonstrate ongoing compliance with the NSPS KKKK NO_X emission limits. Sources demonstrating compliance with the NO_X emission limit via CEMS are not subject to the requirement to perform initial and annual NO_X stack tests.[42] Initial compliance with the NO_X emission limit will be demonstrated by comparing the arithmetic average of the NO_X emissions measurements taken during the initial relative accuracy test audit (RATA) required pursuant to 40 CFR §60.4405 to the NO_X emission limit under NSPS KKKK.[43]

5.1.9.2.2 SO_2 Compliance Demonstration Requirements

For compliance with the SO_2 emission limit, facilities are required to perform regular determinations of the total sulfur content of the combustion fuel and to conduct initial and annual compliance demonstrations. The total sulfur content of gaseous fuel combusted in the combustion turbine must be determined and recorded once per operating day or using a custom schedule as approved by the Division;[44] however, KU elects to opt out of this provision of the rule by using a fuel that is demonstrated not to exceed potential sulfur emissions of 0.060 lb/MMBtu SO_2.[45] This demonstration can be made using one of the following methods:

- By using a purchase contract specifying that the fuel sulfur content for the natural gas is less than or equal to 20 gr/100 scf of sulfur and results in potential emissions not exceeding 0.060 lb/MMBtu; or
- By using representative fuel sampling data meeting the requirements of 40 CFR 75, Appendix D, Sections 2.3.1.4 or 2.3.2.4 which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input.

As shown in the attached permit mark up, KU will accept the fuel sulfur limitation shown in 40 CFR §60.4330(a)(2) of 20 gr/100 scf of sulfur or less.

Pursuant to 40 CFR §60.4365(a), the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifies that the total sulfur content for natural gas used at Brown Generating Station is well below the required 20 gr/100 scf.

5.1.10 Subpart TTTTa – Standards of Performance for GHG Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units (Applicable)

40 CFR 60 *Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine*

[42] 40 CFR 60.4340(a)

[43] 40 CFR 60.4405(c)

[44] 40 CFR 60.4370(b) and (c)

[45] 40 CFR 60.4365

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Electric Generating Units (Subpart TTTTa) is applicable to a stationary CT that commences construction or reconstruction after May 23, 2023, and meets the following relevant applicability conditions in 40 CFR 60.5509a(a)(1) and (2):

- Has a base load rating greater than 250 MMBtu/hr of fossil fuel; and
- Serves a generator(s) capable of selling greater than 25 MW of electricity to a utility power distribution system.

Given that the proposed GT meets all three applicability criteria under 40 CFR §60.5509a(a) and does not meet any of the exemption criteria under 40 CFR §60.5509a(b), the GT will be subject to the provisions of Subpart TTTTa.

Subpart TTTTa provides a different CO_2 emission limit for base load combustion turbines than the limit for intermediate load CTs.

If a stationary combustion turbine supplies greater than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis, then the stationary combustion turbine is a base load CT.

The potential emissions from the GT (EU58) are based on 8,760 hours per year of operation, as a combination of steady-state operations on NG, along with time for shutdowns, idle/non-operation, and cold/hot/warm startups. In one scenario, the worst-case PTE for the GT is based on 7,470 hours of steady state operations and numerous SU/SD events. In the other scenarios, the worst-case PTE also allows for burning NG up to 8,760 hours per year in steady state. These operational hours for calculating the PTE are well above 40% of its electrical output.

If the GT is operated as a base load combustion turbine leading up to the compliance date for Subpart TTTTa, the CT will be subject to the following key requirements under Subpart TTTTa:

- **Phase 1 Standard of Performance for Base Load CTs.** Per 40 CFR §60.5520a(a) and Table 1 of Subpart TTTTa, the 12-operating month averages beginning before January 2032, emissions of CO_2 must be limited to 800 to 1,250 lb CO_2/MWh of gross energy output; **or** 820 to 1,280 lb CO_2/MWh of net energy output, as determined by the procedures in §60.5525a.
- **Phase 2 Standard of Performance for Base Load CTs.** Per 40 CFR §60.5520a(a) and Table 1 of Subpart TTTTa, the 12-operating month averages beginning after December 2031, emissions of CO_2 must be limited to 100 to 150 lb CO_2/MWh of gross energy output; **or** 97 to 139 lb CO_2/MWh of net energy output, as determined by the procedures in §60.5525a.
- **Phases 1 and 2 Standard of Performance for Intermediate Load CTs (Capacity factor greater than 20% and less than 40%):** Per 40 CFR §60.5520a(a) and Table 1 of Subpart TTTTa, the 12-operating month averages beginning before January 2032, emissions of CO_2 must be limited to 1,170 to 1,560 lb CO_2/MWh of gross energy output; **or** 1,190 to 1,590 lb CO_2/MWh of net energy output, as determined by the procedures in §60.5525a
- In addition, per 40 CFR §60.5525a(b), KU must operate and maintain the GT, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if KU is using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

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Per §60.5520a(d)(1), the GT will not be subject to any monitoring or reporting since it is permitted to burn fuels with a consistent chemical composition (i.e., natural gas) resulting in an emission rate less than 160 lb/MMBtu.

5.1.11 Subpart UUUUa – GHG Emissions from Existing Electric Utility Generating Units (Not Applicable)

40 CFR 60 UUUUa was removed and reserved via 89 FR 40047, May 9, 2024.

5.1.12 Subpart UUUUb – Emission Guidelines for GHG Emissions for Electric Utility Generating Units (Not Applicable)

40 CFR 60 *Subpart UUUUb – Emission Guidelines for GHG Emissions for Electric Utility Generating Units* (Subpart UUUUb) provides guidelines for States to follow in developing, submitting, and implementing state plans to establish performance standards to reduce emissions of GHGs from an affected steam generating unit. This final rule became effective on July 8, 2024. The Division is subject to a deadline to submit its Section 111 plan by May 9, 2026. That plan will contain requirements for applicable units. Subpart UUUUb contains design options to develop an approval state plan but does not impose any requirements directly on any sources within a state.

The Division is subject to a deadline to submit its Section 111 plan by May 9, 2026. That plan will contain requirements for applicable units. Subpart UUUUb contains design options to develop an approval state plan but does not impose any requirements directly on any sources within a state. Until EPA approves the state plan (forthcoming in 40 CFR Part 62), affected steam generating units will not be subject to federally enforceable requirements. Once the NGCC is subject to federally enforceable requirements as part of the state plan, KU will provide the final Subpart UUUUb requirements as part of a supplemental DEP7007 V Form, if necessary.

5.2 National Emissions Standards for Hazardous Air Pollutants

NESHAP, located in 40 CFR 61 and 40 CFR 63, have been promulgated for designated pollutants and source categories that emit HAP to the atmosphere. A facility that is a major source of HAP is defined as having potential emissions of greater than 25 tpy of total HAP and/or 10 tpy of any individual HAP. Facilities with a total HAP PTE at an amount less than that of a major source are considered area sources. For major HAP sources, allowable emissions limits are established (under 40 CFR 63) on the basis of a maximum achievable control technology (MACT) determination for the particular source type or category. The NESHAP under 40 CFR 63 apply to sources in specifically regulated industrial source categories (Clean Air Act Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type.

Brown Station will remain a major source for individual HAP and total HAPs.

Any source subject to a NESHAP is also subject to the general provisions of 40 CFR Subpart A, except as noted. A review of all NESHAP that could potentially be applicable to any of the new emission units associated with the NGCC EGU Project is presented in this section. The list of NESHAPs that will apply to the emission units for the project are as follows:

- 40 CFR 63 Subpart YYYY – NESHAP for Combustion Turbines – Applies to the GT (EU58)
- 40 CFR 63 Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines – Applies to the Diesel-Fired Generator/Engine (EU61) and Diesel Pump/Engine (EU62)

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- 40 CFR 63 Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters – Applies to the Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60)

5.2.1 NESHAP Subpart EEEE – Organic Liquids Distribution (Non-Gasoline) (Not Applicable)

40 CFR 63 *Subpart EEEE – National Emission Standards for Hazardous Air Pollutants for Organic Liquids Distribution (Non-Gasoline)* (OLD MACT) applies to any non-gasoline organic liquids distribution (OLD) operation at major sources of HAP emissions. An OLD operation is defined as "the combination of activities and equipment used to store or transfer organic liquids into, out of, or within a plant site regardless of the specific activity being performed." Such activities include the storage of organic liquids.

OLD MACT also defines organic liquids under 40 CFR §63.2406. Paragraph (3)(i) under the definition for "organic liquid" specifically excludes diesel/No. 2 distillate oil from the definition of an organic liquid. As such, the emergency engine ULSFO tank, and fire pump engine ULSFO belly tank will not be affected facilities under OLD MACT.

5.2.2 NESHAP Subpart YYYY – Stationary Combustion Turbines (Applicable)

40 CFR 63 *Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* (NESHAP YYYY) establishes emissions and operating limitations for HAP from existing, reconstructed, or new stationary combustion turbines, located at major stationary sources of HAP. The proposed GT and HRSG with NG-fired DBs (EU58) meets the definition of an affected source under NESHAP YYYY and therefore will be subject to this regulation.[46] Note that the DBs and waste heat recovery units (even if part of a combustion turbine) are explicitly identified as not subject to this rule because they are considered steam generating units and, potentially, subject to other Part 63 standards.

NESHAP YYYY requirements for the GT are dependent on the type of combustion system used (i.e., lean premix or diffusion flame combustion system). A lean premix combustion system operates with a lower flame temperature compared to a diffusion flame combustion system, resulting in lower NO_X emissions. Because the GT utilizes DLN combustor technology, the GT is considered a lean premix gas-fired stationary combustion turbine as defined in 40 CFR §63.6175.

As a lean premix gas-fired stationary GT, the GT will be subject to requirements in Table 5-1. All applicable provisions under NESHAP YYYY are documented on Form V in **Appendix C**.

[46] There was a stay for NESHAP Subpart YYYY in 2004 on all requirements, except for an initial notification; however, this stay was lifted on March 9, 2022. https://www.federalregister.gov/documents/2022/03/09/2022-04848/national-emission-standards-for-hazardous-air-pollutants-stationary-combustion-turbines-amendments

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Table 5-1. NESHAP Subpart YYYY Applicable Requirements

Category	Requirement Summary	Citation
Emission limits	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O_2, except during turbine startup.	40 CFR §63.6100 Table 1
Operating limits	Maintain 4-hour average catalyst inlet temperature within the range suggested by the catalyst manufacturer, excluding data recorded during startup.	40 CFR §63.6100 Table 2
General compliance requirements	Maintain the affected source, including associated air pollution control and monitoring equipment, in a manner consistent with safety and good air pollution control practices.	40 CFR §63.6105
Performance Testing	Conduct an initial performance test within 180 days after startup in accordance with the procedures in §63.6120 and submit a Notification of Compliance Status containing the results.	40 CFR §63.6110 40 CFR §63.6120 40 CFR §63.6130 Table 3 Table 4
	Conduct subsequent performance tests annually in accordance with the procedures in §63.6120.	40 CFR §63.6115 40 CFR §63.6120 Table 3
Monitoring Requirements	Monitor the oxidation catalyst inlet temperature on a continuous basis at all times that the source is operating. Do not use data during malfunctions, associated repairs, or quality assurance/quality control activities in data averages and calculations.	40 CFR §63.6125(a) 40 CFR §63.6135
	Develop and implement a CMS quality control program.	40 CFR §63.6125(e)
	Monitor and record distillate oil usage daily with a non-resettable hour meter to measure the number of hours that distillate oil is fired.	40 CFR §63.6125(d)
	Demonstrate compliance by maintaining oxidation catalyst within the catalyst manufacturer's suggested inlet temperature range.	40 CFR §63.6140(a) Table 5
Notification Requirements	Submit an initial notification within 120 days after startup.	40 CFR §63.6145(b)
	Submit a notification of intent to conduct an initial performance test at least 60 days prior to conducting the initial performance test.	40 CFR §63.6145(e)
	Submit a Notification of Compliance Status within 60 days following the completion of a performance test.	40 CFR §63.6145(f)
Reporting Requirements	Submit a semi-annual compliance report in CEDRI by January 31 and July 31 each year.	40 CFR §63.6140(b) 40 CFR §63.6150(a) 40 CFR §63.6150(g) Table 6
	Submit an annual report of distillate oil firing in CEDRI by January 31 each year.	40 CFR §63.6150(e)
	Submit a performance test report in CEDRI within 60 days after completing each required performance test.	40 CFR §63.6150(f) 40 CFR §63.6150(g)
Recordkeeping Requirements	Keep copies of all notifications, performance tests, startup events, air pollution control equipment maintenance, and deviations for five years.	40 CFR §63.6155 40 CFR §63.6160
	Keep records of daily fuel usage monitors.	40 CFR §63.6155(b)

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5.2.3 NESHAP Subpart ZZZZ – Reciprocating Internal Combustion Engines (Applicable)

40 CFR 63 *Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines* (RICE MACT) regulates HAPs emitted from stationary reciprocating internal combustion engines (RICE) located at major and area source of HAP emissions. The NGCC Project includes two stationary RICE: 1) 2.18 MW Diesel Emergency Generator (EU61) and 2) 422 hp Emergency Diesel Driven Fire Pump Engine (EU62).

Pursuant to 40 CFR §63.6590(c)(6), a new emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake horsepower located at a major source of HAPs (e.g., 422 hp Emergency Diesel Driven Fire Pump engine), must meet the requirements of RICE MACT by meeting the requirements of NSPS IIII for compression ignition engines. No further requirements apply for such engines under this part. Therefore, the emergency use 422 hp Diesel Driven Fire Pump engine will demonstrate compliance with RICE MACT by demonstrating compliance with NSPS IIII.

For the 2.18 MW Diesel Emergency Generator, pursuant to 40 CFR §63.6590(b)(1) and (b)(1)(i), KU does not have to meet the requirements of RICE MACT and of 40 CFR 63, Subpart A except for the initial notification requirements of 40 CFR §63.6645(f).

5.2.4 NESHAP Subpart DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Applicable)

40 CFR 63 *Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* (Boiler MACT) applies to industrial, commercial, or institutional boilers or process heaters, as defined in 40 CFR §63.7575 that are located at, or are part of, a major source of HAP, except as specified in 40 CFR §63.7491. Boiler MACT applies to each new, reconstructed, or existing affected source, where the affected source includes the collection of all existing industrial, commercial, and institutional boilers and process heaters within an applicable subcategory defined in 40 CFR §63.7575 and each new or reconstructed industrial, commercial, or institutional boiler or process heater.

The HRSG and DBs meet the definition of a waste heat boiler, which is excluded from the definition of a boiler. Therefore, Subpart DDDDD is not applicable to the HRSG and DBs.

The Auxiliary Boiler (EU59) is an industrial boiler (95.52 MMBtu/hr) and thus will be subject to Boiler MACT. The Fuel Gas (Dewpoint) Heater (EU60), which is equipped with burners with a heat input capacity of 15.65 MMBtu/hr, is classified as a process heater, and thus will also be subject to Boiler MACT. As these combustion units are designed to use NG as the sole fuel for combustion, they will be categorized as "units designed to burn gas 1 fuels" per 40 CFR §63.7499.

Pursuant to 40 CFR §63.7500(a), the Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU60) must comply with the emission limits and work practice standards presented in Tables 1 through 3 of the Boiler MACT and the operating limitations found in Table 4. Table 1 specifies emissions limitations for new boilers, but this table only includes emissions limitations for units designed to burn solid, liquid, and gaseous fuels defined under the "gas 2" fuel category. As the two new applicable units are considered "units designed to burn gas 1 fuels", they are not subject to any emissions standards. However, these units are subject to a limited number of work practice standards detailed in Table 3 of the rule. These include the requirement to conduct periodic tune-ups where the frequency of the tune-up is dependent on the heat input capacity of the boiler/process heater and the presence of a continuous oxygen trim system that maintains an optimum air-to-fuel ratio.

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- Per 40 CFR §63.7500, KU must conduct a tune-up of the Auxiliary Boiler and NG-Fired Dew Point Heater annually as specified in 40 CFR §63.7540(a)(10), unless the units have continuous oxygen trim systems that maintains an optimum air to fuel ratio. The first tune-up must be no later than 13 months after the initial startup of each boiler, per 40 CFR §63.7515(d).
- Per 40 CFR §63.7530(f), KU must submit a notification of compliance status containing the results of the initial compliance demonstration according to the requirements in 40 CFR §63.7545(e).
- Per 40 CFR §63.7540(b), KU must report any instances it did not meet the tune-up requirements and reported according to the requirements of 40 CFR §63.7550.
- Per 40 CFR §63.7545, KU must submit an initial notification no later than 15 days after the actual date of startup.
- Per 40 CFR §63.7550, KU must submit a compliance report annually.
- Per 40 CFR §63.7555, KU must keep records of each notification and report submitted for 5 years following the date of each occurrence.

KU has documented the relevant Boiler MACT provisions on DEP7007 V Form in **Appendix C**.

5.2.5 NESHAP Subpart UUUUU – Coal & Oil-Fired Electric Utility Steam Generating Units (Not Applicable)

40 CFR 63 *Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units* is referenced to in short as the Mercury and Air Toxics Standards (MATS) and, applies to electric utility steam generating units (EUSGUs) that combust coal or oil.[47] The proposed project does not involve construction or modification of an EUSGU that combusts coal or oil. Therefore, Subpart UUUUU does not apply to emission units associated with the proposed project.

5.3 Compliance Assurance Monitoring (40 CFR 64)

The proposed GT utilizes air pollution controls to reduce emissions of NO_X, CO, VOC, and formaldehyde.

The GT will be subject to NSPS Subpart KKKK, which includes a NO_X standard. Since the NSPS Subpart KKKK NO_X standard is a CAA Section 111 standard that was promulgated after November 15, 1990, the emission limit is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i). The GT will also be subject to a NO_X BACT limit. However, the GT will be equipped with CEMS, which will be required to demonstrate compliance with the NO_X BACT limit in a Part 70 permit. Since the operation of CEMS is a continuous compliance determination method as defined in 40 CFR §64.1, CAM does not apply per §64.2(2)(b)(1)(vi).

The GT will also be subject to NESHAP Subpart YYYY, which includes a formaldehyde standard. Although uncontrolled formaldehyde emissions from the turbine are greater than the Title V major source threshold, NESHAP Subpart YYYY is a CAA Section 112 standard that was promulgated after November 15, 1990 and is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i).

The proposed GT will be subject to BACT limits for CO and VOC emissions. Since emissions of CO and VOC are only controlled during steady state operation, and are not controlled during startup and shutdown, CAM applicability is evaluated based on NG steady state operation. Using this approach, both CO and VOC emissions are greater than the Title V major source threshold pre-control and less than the Title V major source threshold post-control. KU plans to install a CO CEMS on the GT. As discussed previously, operation

[47] 40 CFR 63.9980

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of CEMS is a continuous compliance demonstration method and exempts the CO emissions from the CT from CAM pursuant to 40 CFR §64.2(b)(1)(i). Therefore, CAM does not apply for CO. The GT is not a large PSEU for VOC, and a CAM plan will be submitted upon the first Title V renewal application.

5.4 Risk Management Plans (40 CFR 68)

Subpart B of 40 CFR 68 (RMP Rule) outlines requirements for risk management prevention plans pursuant to Section 112(r) of the CAA. Applicability of the subpart is determined based on the type and quantity of chemicals stored at a facility.

The facility is and will also continue to be subject to the General Duty Clause under the CAA Section 112(r)(1), which states:

> *The owners and operators of stationary sources producing, processing, handling or storing such substances [i.e., a chemical in 40 CFR part 68 or any other extremely hazardous substance] have a general duty [in the same manner and to the same extent as the general duty clause in the Occupational Safety and Health Act (OSHA)] to identify hazards which may result from (such) releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.*

The NGCC EGU Project will use aqueous ammonia at a concentration not to exceed 19%, which is not regulated under the RMP program. Thus, the installation of the NGCC EGU will not affect the plant's current regulated status under the RMP Rule.

5.5 Stratospheric Ozone Protection Regulations (40 CFR 82)

The requirements originating from Title VI of the CAA, entitled *Protection of Stratospheric Ozone*, are contained in 40 CFR 82. Subparts A, B, and F of 40 CFR 82 are potentially applicable to the facility. In particular, 40 CFR 82 Subpart F, *Recycling and Emissions Reduction*, potentially applies if the facility operates, maintains, repairs, services, or disposes of appliances that utilize Class I, Class II, or non-exempt substitute refrigerants.[48] Subpart F generally requires persons completing the repairs, service, or disposal to be properly certified. It is expected that all repairs, service, and disposal of ozone depleting substances from such equipment (air conditioners, refrigerators, etc.) at the facility will be completed by a certified technician. KU will continue to comply with 40 CFR 82 Subpart F. The applicable provisions under 40 CFR 82 are already contained in the plant's existing Title V permit and the project will not necessitate a change to these provisions.

5.6 Interstate Trading Programs

Starting with the ARP mandated by the 1990 Clean Air Act Amendments, EPA has developed several market-based "cap and trade" regulatory programs. All market-based regulatory programs are overseen by EPA's Clean Air Markets Division (CAMD) and are referred to as CAMD regulations. The programs that are potentially applicable to KU are:

- Acid Rain Program (1990 – ongoing)

[48] 40 CFR 82.150

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- Cross-State Air Pollution Rule (2015 – ongoing)

5.6.1 Acid Rain Applicability

To reduce acid rain in the United States and Canada, Title IV (40 CFR 72 *et seq.*) of the CAA Amendments of 1990 established the ARP to substantially reduce SO_2 and NO_X emissions from electric utility plants. Kentucky incorporates the ARP by reference per 401 KAR 52:060, Acid Rain Permit. Affected units are specifically listed in Tables 1 and 2 of 40 CFR 73.10 under Phase I and Phase II of the program. Upon Phase III implementation, the ARP in general applies to fossil fuel-fired combustion sources that drive generators for the purposes of generating electricity for sale. The proposed GT will be a utility unit subject to the ARP. The facility is subject to the requirements of 40 CFR 72 (permits), 40 CFR 73 (SO_2), and 40 CFR 75 (monitoring); however, the GT will not be subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the proposed GT does not have the capability to burn coal. KU is required to apply for the ARP permit at least two years prior to commencing operation of the proposed GT.[49]

5.6.2 Cross-State Air Pollution Rule

CSAPR implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule. Upon reviewing the existing Title V permit for Brown Station, KU is requesting that the Division consider removing the CAIR requirements.

KU's proposed GT will be an affected source under this regulation, and must comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR §§ 97.830 through 97.835 (Expanded Group 2 Program). KU is required to monitor emissions of SO_2, NO_X, and maintain sufficient allowances under CSAPR for its operations. Monitoring requirements for NO_X mass emissions and individual unit heat input, including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, typically tie back to ARP requirements per 40 CFR Part 75.[50] KU will comply with the requirements of this rule upon startup of the GT.

5.7 Kentucky SIP Regulations

The new emissions units associated with the NGCC EGU Project are also subject or potentially subject to Kentucky Administrative Regulations (401 KAR).

5.7.1 401 KAR 51:017 and 52:020 – PSD and Title V Permitting Programs (Applicable)

The Brown Station is located in an unclassified/attainment area for all criteria pollutants. Therefore, with respect to the Kentucky NSR permitting program, only PSD requirements could potentially apply to the source. As discussed in **Section 4,** emissions increases of PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4, and GHG from the NGCC EGU Project exceed the applicable PSD triggering thresholds, and thus, PSD permitting requirements for these pollutants are addressed in this application. Applicable PSD permitting requirements include the completion of a BACT analysis, which is presented in **Sections 6** through **10**, and a PSD Air Quality Analysis and Additional Impacts Analysis, which will be presented in **Volume 2**.

[49] 40 CFR 72.30(b)(2)(ii)

[50] 40 CFR §97.1029(a)(1) Requirements for installation, certification, and data accounting

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The NGCC EGU Project and the existing legacy Brown operations are regulated under the Title V permit program. Pursuant to 401 KAR 52:020, Section 3, a major source shall not construct, reconstruct, or modify without a permit or permit revision, except as provided for administrative revisions, minor revisions, off-permit changes, and 502(b)(10) changes. This application package provides information required under 401 KAR 52:020, Section 4, 5, and 16 for the purposes of a SPR to a Title V and PSD source. Completed DEP7007 series application forms for the proposed project are provided in **Appendix C** of the application package.

5.7.2 401 KAR 53:010 – Kentucky Ambient Air Quality Standards for Gaseous Fluorides

401 KAR 53:010 establishes ambient air quality standards (AAQS) for HF and total fluorides for the state of Kentucky. Total fluoride standards are expressed as a dry weight measure of fluoride ions in and on forage for consumption by grazing ruminants. Concentrations are assessed on a one-month, two-month, and growing season average basis. Gaseous fluoride standards are expressed as ambient concentration limits of HF for both short-term and annual averaging periods. The fluoride standards apply generally to all sources but are typically only addressed in permit applications and associated permits for sources with expected or measurable fluoride emissions. The regulatory text in 401 KAR 53:010 does not specify when or how a source has to evaluate compliance with the ambient standards for fluorides.

The new emission units associated with the NGCC EGU Project are not expected to have significant levels of gaseous fluoride emissions, and thus will not result in any ambient concentrations exceeding the gaseous fluoride AAQS.

5.7.3 401 KAR 59:010 – New Process Operations (Applicable)

Pursuant to 401 KAR 59:010, Section 1(1), particulate emissions from new process operations not subject to other emission standards with respect to particulates in Chapter 59 and that are constructed after July 2, 1975, are subject to this generally applicable rule. The affected operations covered include any "method, form, action, operation, or treatment of manufacturing or processing, and shall include any storage or handling of materials or products, before, during, or after manufacturing or processing." Section 3 of the rule establishes the following opacity and mass emissions standards:

- Pursuant to 401 KAR 59:010, Section 3(1)(a), the continuous emission into the open air from a control device or stack associated with the affected facility shall be less than 20 percent opacity.

- Pursuant to 401 KAR 59:010, Section 3(2), the PM emissions into the open air from a control device or stack associated with the affected facility shall not exceed the process weight equation limitation of $E = 3.59(P)^{0.62}$, where E = PM emission limit in lb/hr and P = process rates greater than 0.5 tph and less than 30 tph. For process weight rates equal to and less than 0.5 tph, E = 2.34 lb/hr. For process weights in excess of 30 tph, $E = 17.31(P)^{0.16}$.

This regulation will be applicable to the mechanical draft cooling tower (EU63) in accordance with current Division interpretations of this regulation concerning cooling towers generally. Based on its design and characteristics, the cooling tower can be presumed to be in compliance with 401 KAR 59:010 when it is operated and maintained in accordance with the manufacturer's specifications and recommendations.

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5.7.4 401 KAR 59:015 – New Indirect Heat Exchangers (Applicable)

This regulation applies to equipment, apparatus, or contrivances used for the combustion of fuel in which the energy produced is transferred to its point of usage through a medium that does not come into contact with or add to the products of combustion. Affected sources must have a heat input capacity greater than 1 MMBtu/hr.

The HRSG with DB Firing (part of EU58), Auxiliary Boiler (EU59), Fuel Gas (Dewpoint) Heater (EU60) meet the definition of indirect heat exchangers under 401 KAR 59:015 and are new affected facilities. Section 4 of 401 KAR 59:015 establishes opacity standards and heat input-based PM emission limits. Pursuant to 401 KAR 59:015, Section 4(2), opacity of continuous emissions from the two (2) indirect-fired heat exchangers are limited to 20%, except that a maximum of 40% shall be allowed for a maximum of six (6) consecutive minutes in any sixty (60) minute period during fire-box cleaning or soot blowing events.

The applicable PM emission limit is determined based on the total heat input capacity for all the affected facilities at the source at the time of construction of the new units. A different heat input-based PM allowable emission rate applies depending on whether the total heat input capacity for the facility is less than 10 MMBtu/hr, between 10 MMBtu/hr and 250 MMBtu/hr, or above 250 MMBtu/hr. The sum of the heat input capacities for the two new units plus the existing affected facilities is greater than 250 MMBtu/hr; therefore, the allowable PM emission factor using the applicable algorithm presented in 401 KAR 59:015, Section 4(1)(b), is 0.10 lb PM/MMBtu. The potential PM emission factor from combusting NG in the new heat exchangers is orders of magnitude lower than the allowable PM emission rate, so KU will be implicitly in compliance with these emission limits when burning NG.

Section 5 of the rule establishes SO_2 emissions standards. The SO_2 emissions standard is also limited based on the total heat input capacity for all affected facilities at the source. A different heat input capacity-based allowable emission rate algorithm applies based on the type of fuel to be burned (e.g., solid, liquid, or gaseous) and whether the total, facility-wide affected facility heat input capacity falls within one of the same ranges discussed above for the PM emission limit derivation. The allowable SO_2 emission factor using the applicable algorithm presented 401 KAR 59:015, Section 5(1)(b)1, is 0.8 lb SO_2/MMBtu. Again, the potential SO_2 emission factor from combusting NG in the Brown Station's 401 KAR 59:015-affected units is orders of magnitude lower than the allowable SO_2 emission rate, so KU will be implicitly in compliance with these emission limits when burning NG.

In addition to the emission limits, work practice standards must be met during periods of SSM and certain procedures must be followed for startup and shutdown periods (defined in the rule). Because EU59 and EU60 are subject to 40 CFR 63, Subpart DDDDD, these units must meet the work practices standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD pursuant to 401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a). The HRSG with DBs must comply with the work practice standards in 401 KAR 59:015, Section 7(1).

5.7.5 401 KAR 59:050 – New Storage Vessels for Petroleum Liquids (Not Applicable)

Pursuant to 401 KAR 59:050 Section 2(1), an "affected facility" is a storage vessel for petroleum liquids with storage capacity greater than 580 gallons. Pursuant to 401 KAR 59:050, Section 2(3), "petroleum liquids" does not mean diesel FOs amongst others. Therefore, the planned FO tanks would not fall into the definition of "petroleum liquids" so they are exempt from the regulation.

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5.7.6 401 KAR 63:010 – Fugitive Emissions (Applicable)

The paved haul roads have the potential to generate fugitive PM emissions that are regulated under 401 KAR 63:010. 401 KAR 63:010 is a generally applicable standard that requires reasonable precautions be taken to prevent airborne PM emissions. In accordance with 401 KAR 63:010, KU will take reasonable precautions as described in the regulation to prevent fugitive emissions from the project affected sources. KU will also ensure no visible fugitive dust emissions from the proposed plant are discharged beyond the property line. Subject sources are indicated in the applicable DEP7007 V Form included in **Appendix C.**

5.7.7 401 KAR 63:020 – Potentially Hazardous Matter or Toxic Substances (Applicable)

Kentucky regulates the emissions of toxic air pollutant emissions through 401 KAR 63:020. The Division can require that dispersion modeling or other analyses be completed by facilities at permit renewal or when constructing equipment when there is an increase in toxic pollutant emissions, as defined under 401 KAR 63:020, Section 2(2), deemed to be "significant." This is done so that there is a documented basis for affirming that a facility does not cause an adverse impact. However, pursuant to 401 KAR 63:020, Section 1, the requirements of this rule are applicable only to the extent that such emissions are not elsewhere subject to the provisions of the KAR.

Emissions from all NESHAP/MACT-affected emission units have been incorporated in 401 KAR 63:002, Section 2. Since the toxic air pollutant emissions are already regulated under a NEHSAP/MACT, no additional requirements under 401 KAR 63:020 will apply.

Some relatively small, low emitting sources of air toxics included in the project scope (i.e., storage tanks) have the potential to generate trace quantities of air toxics, but a "no adverse impact" determination can be qualitatively asserted based on the negligible emissions levels from these sources. Therefore, KU does not intend to prepare a refined air dispersion modeling analysis to evaluate ambient impacts of air toxics emissions from the proposed project, as they will not cause or contribute to adverse impacts.

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6. BACT ANALYSIS METHODOLOGY

As the proposed project is expected to result in emission increases of PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4 Mist, and GHG emissions in excess of the NSR major modification thresholds, an analysis to ensure the implementation of BACT is required for the new units being proposed as part of this project which have the PTE any of those pollutants. A technical review has been performed to investigate and identify emission controls that have recently been determined by various permitting authorities across the U.S. to satisfy BACT requirements.

6.1 BACT Introduction

Any new major stationary source or any major modification at an existing stationary source subject to PSD review must conduct an analysis to ensure the use of BACT. The requirement to conduct a BACT analysis is set forth in 40 CFR 52.21 and 401 KAR 51:017 Section 8. Kentucky's PSD regulations define BACT as:[51]

> *"an emissions limitation, including a visible emission standard, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification* and:
>
> *(a) Is determined by the cabinet on a case-by-case basis after taking into account energy, environmental, and economic impacts and other costs, to be achievable by the 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 that pollutant;*
>
> *(b) Does not result in emissions of a pollutant that would exceed the emissions allowed by an applicable standard of 40 C.F.R. Parts 60 and 61; an*d
>
> *(c) Is satisfied by a design, equipment, work practice, or operational standard or combination of standards approved by the cabinet, if:*
>
> *1. The cabinet determines technological or economic limitations on the application of measurement methodology to a particular emissions unit would* make the imposition of an emissions standard infeasible;
> *2. The standard establishes the emissions reduction achievable by implementation of the design, equipment, work practice or operation; and*
> *3. The standard provides for compliance by means that achieve equivalent results."*

In accordance with Kentucky's PSD regulations, BACT is determined on a pollutant-by-pollutant basis for each pollutant for which there is a significant net emissions increase. The BACT review covers new and modified emission units associated with the project.

The emissions increases are presented in **Section 4** along with each pollutant's corresponding PSD SER. As shown in **Section 4**, the project emissions of CO, NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, and H_2SO_4 from the project will exceed the SER for non-GHG regulated NSR pollutants and the "subject to regulation" threshold for GHG. Therefore, these pollutants are subject to BACT review. Consistent with the approach used by KDAQ

[51] 401 KAR 51:001 Section 1 (25).

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for other permitted projects, a "top-down" BACT analysis organized by pollutant and by emissions source category is presented in the following sections of the application. The proposed BACT emission limitations for each emissions source considered in the analysis apply *at all times*.

6.2 BACT Determination Methodology

Consistent with KDAQ's implementation of the BACT requirements under 401 KAR 51:017, BACT for the proposed project has been evaluated via a "top-down" approach. Under this identified top-down approach, the most stringent control available for a similar or identical source or source category is identified. This control option is used to establish the BACT emission limitation unless the applicant can demonstrate (and the permitting authority agrees) that it is not "achievable" due to technical infeasibility or not being cost-effectiveness or other adverse environmental or energy consequences of implementing the technology. If the top control alternative is eliminated, then the next most stringent level of control is evaluated. This process continues until the control option under consideration cannot be eliminated by any source specific adverse environmental, energy, or economic impacts.

6.2.1 BACT Step 1 – Identify All Control Technologies

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical infeasibility and not being cost-effectiveness, or environmental and energy impacts, all control technologies with potential application to the emission unit under review should be identified.

The following resources are typically consulted when identifying potential technologies:

1. The Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Previous engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

Potentially applicable emission control technologies were identified by researching the EPA control technology database, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC, a database made available to the public through the EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

RBLC database search were performed for each emission unit type to initially identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years (or further back in the RBL database's historical record where necessary to ensure an adequate number of representative BACT determinations were included in the RBLC output) for emission sources

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comparable to the proposed new included in the NGCC EGU Project scope. **Appendix D** includes the RBLC search results.

6.2.2 BACT Step 2 – Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether a technology is feasible is whether it has been "demonstrated" in practice. If so, it is feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination. Demonstrated means that it has been installed and operated successfully elsewhere on a similar facility.

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available." Control technologies in the research and development and pilot scale phases are not considered available. An available control technology is presumed to be applicable if it has been permitted or implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative.

6.2.3 BACT Step 3 – Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

6.2.4 BACT Step 4 – Evaluate Most Effective Controls and Document Results

After identifying available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration, then it is selected as BACT. Alternatively, if adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until an achievable control technology is identified.

6.2.5 BACT Step 5 – Select BACT

In the final step, one pollutant specific control option establishes BACT for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

BACT must reflect emission rates less than or equal to any applicable NSPS or NESHAP emission standards for the source under review. In any case where NSPS or NESHAP emission limits for certain pollutants will apply to proposed equipment and effectively set the floor for BACT for these units, the Step 5 BACT selection process notes these applicable NSPS or NESHAP standards and notes how they were considered in setting the proposed BACT limit.

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6.3 Defining the Source

The EPA's NSR Workshop Manual states:

> *Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.*[52]

The courts have confirmed EPA's use of a two-part test for determining when a considered control for the purposes of BACT illegitimately redefines the proposed source. The United States Court of Appeals for the Ninth Circuit has summarized and adopted the EPA's two-part test for determining when the evaluation of an alternative production process as a control technology veers into an illegitimate redefinition of the source proposed by the permit applicant.

> *First, "the permit applicant initiates the process and … defines the proposed facility's end, object, aim or purpose—that is the facility's basic design." The purpose must be "objectively discernable." Additionally, the applicant's proposed definition "must be for reasons independent of air permitting" and cannot be motivated by cost savings or avoidance of risks.*
>
> *Second, EPA takes a "hard look" at the proposed definition to determine which design elements are inherent to the applicant's purpose and which elements can be changed to reduce pollutant emissions without disrupting the applicant's basic business purpose.*[53]

The Court's two-part test can be further characterized as follows:

- Part A: The applicant defines the project in a way that addresses:
  - The purpose of the project, and
  - The basic design and location to meet the project purpose.
- Part B: EPA reviews the Applicant's stated purpose and basic design elements:
  - Are the design elements inherent to the purpose?
  - Could any basic design element change without impacting the project purpose?

In general, EPA does not consider options that fundamentally redefine a source to be "available" under Step 1 of a BACT analysis. While the NSR Workshop Manual identifies three types of control options that should be considered under Step 1 (i.e., inherently lower-emitting processes/practices, add-on controls, and combinations thereof), lower-emitting processes that redefine the source should be excluded from Step 1.[54] Within Sections 1 and 2, KU has outlined its stated purpose of the project and corresponding new equipment specifications which collectively define its goal, objectives, purpose, and basic design for the proposed new sources and existing source modifications, if any, covered by this application.

6.4 BACT Requirements

For this project, the BACT requirement applies to each new unit which will emit pollutants subject to PSD review. The proposed facility is subject to PSD permitting for CO, VOC, NO_X, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHGs. The control technology analysis for $PM_{2.5}$ addresses only direct $PM_{2.5}$ emissions since separate

[52] NSR Workshop Manual, page B-13.

[53] *Helping Hands Tools v. Envtl. Prot. Agency*, 848 F.3d 1185, 1194 (9th Circuit 2016).

[54] Prairie State Generating Company, PSD Appeal No. 05-05 (Environmental Appeals Board [EAB], August 24, 2006).

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analyses were performed for $PM_{2.5}$ precursors (i.e., NO_X). Table 6-1 identifies the pollutants considered in the PSD BACT analysis for each emission unit.

Table 6-1. Pollutants Evaluated in the BACT Analysis for Each Emission Unit

Equipment	CO (Yes/No)	NO_X (Yes/No)	$PM/PM_{10}/PM_{2.5}$ (Yes/No)	VOC (Yes/No)	H_2SO_4 Mist (Yes/No)	GHGs (Yes/No)
EU58 NGCC	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU59 Auxiliary Boiler	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU60 Dewpoint Heater	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EU61 Diesel Generator/Engine	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**
EU62 Diesel Fired Fire Pump	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**
EU63 Cooling Tower	**No**	**No**	**Yes**	**No**	**No**	**No**
EU64 Turbine Circuit Breaker	**No**	**No**	**No**	**No**	**No**	**Yes**
EU65 Demister Vents	**No**	**No**	**No**	**Yes**	**No**	**No**
EU66/67 Diesel Storage Tanks	**No**	**No**	**No**	**Yes**	**No**	**No**
EU68 NGCC Haul Roads	**No**	**No**	**Yes**	**No**	**No**	**No**
EU69 NG Piping Fugitives	**No**	**No**	**No**	**Yes**	**No**	**Yes**
EU70 Sulfuric Acid Tank	**No**	**No**	**No**	**No**	**Yes**	**No**

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7. BACT ANALYSIS FOR NGCC

The proposed NGCC is a natural gas-fired combined cycle unit. As discussed in Section 6.2, the primary data source for this analysis is the RBLC. Appendix D provides a list of recent RBLC determinations for NGCCs (Process Type Code 15.210 – Combined Cycle & Cogeneration >25MW, NG-Fired) from the most recent 10-year period, excluding units that are not representative of the proposed NGCC. Excluded NGCC units include those that:

- Have not been constructed,
- Have not undergone performance testing to demonstrate the achievability of BACT emission limits,
- Are not used exclusively for electricity generation, or
- Are not comparable due to differences in fuel type or turbine size.

Additionally, KU excluded NGCC units with a maximum capacity of less than 850 MMBtu/hr or 100 MW, as they are not directly comparable to the proposed H-class turbine. For Step 5 of the analysis, only sources with more stringent (i.e., lower) permitted emissions limits have been evaluated for comparison to the proposed limits. Therefore, units with equivalent or higher permitted emissions limits are not represented in the pollutant-specific RBLC summary tables in the following subsections. However, information on these units is included in Appendix D.

7.1 CO BACT Evaluation for NGCC

The following sections present a review of pollutant formation and possible control technologies for CO emissions from the GT in a combined cycle mode. Air pollution control strategies are evaluated using the top-down BACT approach. An oxidation catalyst system will be installed and operated to control CO emissions from NG-firing in the GT with or without the DBs.

7.1.1 Background on Pollutant Formation

CO emissions from the NGCC result from incomplete combustion. Factors contributing to incomplete combustion include insufficient oxygen availability, poor fuel-air mixing, lower combustion temperatures, reduced combustion gas residence time, and load reductions.

7.1.2 Step 1 – Identification of Potential Control Technologies

CO emissions can be reduced through two primary approaches: combustion control techniques and post-combustion control methods. Combustion control techniques focus on optimizing the design of the combustion process and implementing effective combustion and operating practices. Post-combustion control is achieved through the use of an oxidation catalyst.

Table 7-1. Potential CO Control Technologies for NGCC

Pollutant	Control Technologies
CO	Oxidation Catalyst EM$_x$™/SCONO$_x$™/METEOR™ Good Combustion and Operating Practices

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7.1.2.1 Oxidation Catalyst

The chemical reactions in the exhaust stream resulting from application of an oxidation catalyst are as follows:

$CO + ½\ O_2 \rightarrow CO_2$
$C_nH_m + (n + m/4)\ O_2 \rightarrow n\ CO_2 + (m/2)\ H_2O$
$C_nH_mO + (n + m/4 - 0.5)\ O_2 \rightarrow n\ CO_2 + (m/2)\ H_2O$
$2H_2 + O_2 \rightarrow 2H_2O$

Oxidation catalysts are formulated with precious metals, such as platinum group metals, and are applied to flow-through monoliths to minimize backpressure and maintain a compact design. Various catalyst formulations provide the flexibility to target specific conversion requirements, exhaust temperatures, and low SO_2 to SO_3 and NO to NO_2 conversions. Oxidation catalysts can provide up to 90% destruction of CO, VOCs, formaldehyde, and other toxic compounds.[55] See Section 4.3 of **Appendix B** for the methodologies used to calculate the control efficiencies used for the emissions from the new CT.

7.1.2.2 EM$_X$™/SCONO$_X$™/METEOR™

EM_X™ (the second-generation of the $SCONO_X$ NO_X Absorber Technology) is a multi-pollutant control technology that utilizes a coated oxidation catalyst to remove both NO_X, CO, and VOC without a reagent, such as NH_3. The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate [$K_2(CO_3)$] to oxidize NO_X (to potassium nitrate [$K(NO_3)$]), CO (to CO_2), and VOC.[56] Hydrogen (H_2) is then used as the basis for the catalyst regeneration process where $K(NO_3)$ is reacted to reform the $K_2(CO_3)$ catalyst and release nitrogen gas and water.[57] The catalyst is installed in the flue gas with a temperature range between 300°F to 700°F. These catalysts are susceptible to fouling by sulfur if the sulfur content of the flue gas is high.[58] METEOR™ is a multi-pollutant post-combustion control technology originally developed and patented by Siemens Energy Inc. and optimized by Cormetech.

These multi-pollutant control systems use an oxidation catalyst that provides an equivalent level of control for CO emissions to other oxidation catalysts, and therefore, they do not separately need to be carried to the remaining steps of the turbine BACT analysis.

7.1.2.3 Good Combustion and Operating Practices

This control technology minimizes incomplete combustion and the resulting formation of CO through proper equipment design and operation, and good combustion practices. Proper equipment design minimizes incomplete combustion by allowing for sufficient residence time at high temperatures and turbulence to increase mixing. Generally, the effect of combustion zone temperature and residence time on CO emissions is the opposite of their effect on NO_X emissions. Accordingly, oxygen availability is also optimized with input air, while controlling temperature to minimize NO_X formation. Modern turbine control systems enhance combustion efficiency by automatically adjusting operating parameters through computer-based technology.

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[55] https://www.murcal.com/pdf%20folder/15.johnson_turbine_lit2.pdf

[56] Georgia EPD, *Prevention of Significant Air Quality Deterioration Review Preliminary Determination – Dahlberg Combustion Turbine Electric Generating Facility*, October 2009. https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/1570034pd.pdf

[57] Ibid.

[58] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, pages 8.1E-9 and 8.1E-10.

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7.1.3 Step 2 – Elimination of Technically Infeasible Control Options

The second step in the BACT process is the elimination of technically infeasible control options based on process-specific conditions that prohibit implementation of the control, or the lack of commercial demonstration of achievability.

7.1.3.1 Oxidation Catalyst

Oxidation catalysts typically operate within a temperature range between 600 to 800°F.[59] In combined cycle operation, the presence of a HRSG to recover useful thermal output from the turbine exhaust gas lowers the gas temperature into the oxidation catalyst's operating range. As the proposed NGCC will only fire NG and has a predictable emissions profile, an oxidation catalyst is technically feasible for the proposed NGCC.

7.1.3.2 Good Combustion and Operating Practices

This represents the base case for design and operation of the combustion turbines.

7.1.4 Step 3 – Rank Remaining Control Technologies

The only technically feasible add-on control technology to reduce emissions below the base case (good combustion and operating practices) is an oxidation catalyst. As a technically feasible control option, it must be evaluated further in the BACT process.

7.1.5 Step 4 – Evaluation of Most Stringent Control Technologies

Oxidation catalyst is the highest ranking potentially feasible control technology for the NGCC. As such, KU is proposing installation of this option, alongside good combustion and operating practices (GCOP), as BACT.

7.1.6 Step 5 – Selection of BACT

7.1.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

There is no floor for an allowable CO BACT limit since there is no applicable NSPS or NESHAP standard. The NGCC will also not be subject to any CO emission limit under Title 401 of the Kentucky Administrative Rules.

7.1.6.2 Summary of RBLC Review

Table 7-2 summarizes the CO RBLC entries for combined cycle turbines combusting NG, and that pass the aforementioned exclusion criteria. Only those limits that are lower than the proposed limit of 2 ppmvd @ 15% O_2 are included in this table. Detailed RBLC search results are provided in **Appendix D.**

[59] U.S. EPA, *CATC Fact Sheet for Catalytic Incineration*, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

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Table 7-2. CO RBLC Entries for NGCC

RBLC ID	Facility	Permit Date	Permitted CO Limit w/o DB	Permitted CO Limit w/ DB	Units	Averaging Period
CT-0158	CPV Towantic Energy Center	11/30/2015	0.9	1.7	ppm_{vd} @ 15% O_2	1 Hour
CT-0161	Lake Road Energy Center	6/30/2017	0.9	1.7	ppm_{vd} @ 15% O_2	1 Hour
VA-0325	Greensville Power Station	6/17/2016	1	1.6	ppm_{vd} @ 15% O_2	3-Hour
IL-0130	Jackson Energy Center	12/31/2018	1.5	2.0	ppm_{vd} @ 15% O_2	3-Hour

A significant number of RBLC entries for combined cycle combustion turbines utilize oxidation catalyst and good combustion practices to achieve a BACT limit of 2 ppmvd. The lowest emissions presented for comparable units range from 0.9 to 2.0 ppmvd without DBs and 1.7 to 2.0 ppmvd with DBs. With the exception of Greensville Power Station, the remaining entries are within ozone nonattainment areas that are subject to NNSR requirements for VOC. NNSR requires the implementation of LAER rather than BACT, which requires the most stringent emission limit without considering factors such as cost, energy consumption, or environmental impact. Since oxidation catalyst is used to achieve the VOC LAER requirements and is also used to achieve CO emissions reduction, the CO emission limits for these sites were established to comply with LAER requirements and are more stringent than BACT.

The Greensville Power Station operates three Mitsubishi M501J-class turbines, which is not the same class of GT as proposed for Brown Station. Even so, that unit did set BACT for fired and unfired modes at 1.6 and 1 ppm_{vd} @15% O_2, respectively.

The vast majority of limits in the RBLC (over 40 entries) are consistent with or greater than the proposed limit of 2.0 ppmvd at 15% O_2, including other recently permitted H-class turbines.

7.1.6.3 CO BACT Limit Selection – Steady-State Operation

KU is proposing BACT for the NGCC firing NG, with or without DBs, as the use of oxidation catalyst technology and good combustion practices. KU proposes a BACT limit for CO of 2.0 ppmvd, corrected to 15% O_2, on a 30-day averaging basis, excluding periods of startup and shutdown (see Section 7.7 for SU/SD BACT). The proposed limit is equivalent to multiple recently approved NGCC BACT limits. KU proposes to demonstrate compliance via CO CEMS.

7.2 VOC BACT Evaluation for NGCC

The following sections present a review of pollutant formation and possible control technologies for VOC emissions from the GT in a combined cycle mode. Air pollution control strategies are evaluated using the top-down BACT approach. An oxidation catalyst system will be installed and operated to control VOC emissions from NG-firing in the GT with or without the DBs.

7.2.1 Background on Pollutant Formation

VOC emissions result from incomplete combustion. VOCs are released into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. VOC emissions from

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turbines are affected by load and are typically higher at low load than at high load, due to the decreased efficiency of fuel combustion.

7.2.2 Step 1 – Identification of Potential Control Technologies

The available control technologies for VOC are listed below in Table 7-3.

Table 7-3. Potential VOC Control Technologies for NGCC

Pollutant	Control Technologies
VOC	Oxidation Catalyst EM$_x$™/SCONO$_x$™/METEOR™ Good Combustion and Operating Practices

7.2.2.1 Oxidation Catalyst

Oxidation catalyst control technology is discussed in detail in Section 7.1.2.1.

7.2.2.2 EM$_x$™/SCONO$_x$™/METEOR™

EM$_x$™/SCONO$_x$™/METEOR™ is described in detail in Section 7.1.2.2. These systems utilize an oxidation catalyst that achieves an equivalent level of control of VOC emissions to other oxidation catalysts and are therefore not separately carried through this analysis.

7.2.2.3 Good Combustion and Operating Practices

GCOP is discussed in detail in Section 7.1.2.3.

7.2.3 Step 2 – Elimination of Technically Infeasible Control Options

7.2.3.1 Oxidation Catalyst

Oxidation catalysts typically operate within a temperature range between 600 to 800°F.[60] The exhaust temperature from the combined cycle turbines falls well within the operating temperature of typical oxidation catalyst systems. Therefore, oxidation catalyst is considered technically feasible for the proposed NGCC.

7.2.3.2 Good Combustion and Operating Practices

This represents the base case for design and operation of the combustion turbines.

7.2.4 Step 3 – Rank Remaining Control Technologies

The only technically feasible add-on control to reduce emissions is the use of oxidation catalysts along with good combustion practices. As a technically feasible control option, it must be evaluated further in the BACT process.

[60] U.S. EPA, *CATC Fact Sheet for Catalytic Incineration*, EPA-452/F-03-018. Available at: www.epa.gov/ttn/catc/dir1/fcataly.pdf

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7.2.5 Step 4 – Evaluation of Most Stringent Control Technologies

Oxidation catalyst is the highest ranking potentially feasible control technology for the proposed NGCC. KU is proposing installation of oxidation catalyst with good combustion practices as the most effective means for reducing emissions of VOC from the NGCC.

7.2.6 Step 5 – Selection of BACT

7.2.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The GT will not be subject to any NSPS or NESHAP standard for VOC[61] and thus there is no floor for an allowable VOC BACT limit. The GT will also not be subject to any VOC emission limit under Title 401 of the Kentucky Administrative Rules.

7.2.6.2 Summary of RBLC Review

EPA's RBLC database was reviewed to determine what has been established as a BACT emission requirement for comparable operations. The results of this review are presented in Table 7-4, which include VOC RBLC database entries for NG fired combustion turbines with and without DBs. These entries are potentially comparable to the proposed NGCC unit operating with an oxidation catalyst for VOC emission reductions. Detailed RBLC search results are presented in **Appendix D.**

Table 7-4. VOC RBLC Entries for NGCC

RBLC ID	Facility	Permit Date	Permitted VOC Limit (w/o DB)	Permitted VOC Limit (w/ DB)	Units	Averaging Period
CT-0161	Lake Road Energy Center	6/30/2017	0.7	1.6	ppm_{vd} (15% O_2)	Not indicated
VA-0325	Greensville Power Station	6/17/2016	0.7	1.4	ppm_{vd} (15% O_2)	Not indicated
NY-0103	Cricket Valley Energy Center	2/3/2016	0.7	1.8	ppm_{vd} (15% O_2)	1 Hour
VA-0335	Panda Stonewall, LLV	12/18/2020	1	1.5	ppm_{vd} (15% O_2)	Not indicated
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	11/17/2017	1	1	ppm_{vd} (15% O_2)	Not indicated
PA-0310	CPV Fairview Energy Center	9/2/2016	1	1.5	ppm_{vd} (15% O_2)	Not indicated
PA-0307	York Energy Center	6/15/2015	1.5	1.9	ppm_{vd} (15% O_2)	Not indicated

The majority of RBLC entries for combined cycle combustion turbines utilize oxidation catalyst and good combustion practices to achieve a BACT limit of 1 to 2 ppmvd when not firing DBs and 2 ppmvd when firing DBs, including several recently permitted sites. The lowest emissions presented for comparable units are 0.7 ppmvd without DB firing, and 1.4 to 1.9 ppm_{vd} with DB firing.

[61] The GT will be subject to 40 CFR 63 Subpart YYYY, which does limit emissions of formaldehyde, a component of VOC. However, for the purposes of this BACT analysis, KU is only considering standards that would apply to total VOC.

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Two of the RBLC database entries shown above are located in ozone nonattainment areas or are part of the OTR, requiring NNSR. These facilities and their locations are listed below, along with the ozone nonattainment status of each location:

- CT-0161 – Lake Road Energy Center – Windham County, CT
  - Serious (2015)
  - Serious (2008)
- NY-0103 – Crickett Valley Energy Center – Dutchess County, NY
  - OTR
- VA-0335 – Panda Stonewall, LLV – Loudoun County, VA
  - OTR
  - Moderate (2015)
- PA-0310 – CPV Fairview Energy Center – Cambria County, PA
  - OTR
- PA-0307 – York Energy Center
  - OTR

As these facilities are located in ozone nonattainment areas or the OTR, they are subject to NNSR requirements for VOC, which mandate the implementation of LAER rather than BACT. LAER, unlike BACT, solely focuses on achieving the most stringent emission limit without considering factors such as cost, energy consumption, or environmental impact. The VOC limits were ultimately set to comply with LAER requirements and are more stringent than what would have been required under BACT requirements.

As noted above, the NGCC plant in operation at the Greensville Power Station are Mitsubishi M501J-class turbines and they set VOC BACT for fired and unfired modes at 1.4 and 0.7 ppm_{vd} @15% O_2, respectively.

The remaining limits in the RBLC are consistent with or greater than the proposed limits of 1.0 ppmvd at 15% O_2 unfired and of 2.0 ppm_{vd} at 15% O_2 when firing DBs.

7.2.6.3 VOC BACT Limit Selection – Steady-State Operation

Based on a review of the emission limits achievable and recent BACT determinations for similar facilities, KU is proposing BACT as 1.0 ppm_{vd} at 15 percent O_2 (as methane) without DB firing and 2.0 ppmvd at 15 percent O_2 (as methane) with DB firing, both on a 3-hour rolling average basis utilizing oxidation catalyst and good combustion practices. These limits exclude periods of startup and shutdown (see Section 7.7 for SU/SD BACT). The proposed limits are at the low end of the range of the recently permitted combined cycle generating units as demonstrated in the RBLC data in **Appendix D**. In addition, the proposed control technologies are consistent with the top levels of controls for combined cycle generating units. Therefore, BACT is satisfied. KU proposes to demonstrate compliance via initial performance testing, compliance with NESHAP YYYY, and monitoring the inlet temperature into oxidation catalyst bed.

7.3 NO_X BACT Evaluation for NGCC

The following sections present a review of pollutant formation and possible control technologies for NO_X emissions from the NGCC. in a combined cycle mode. Air pollution control strategies are evaluated using the top-down BACT approach. Air pollution control strategies are evaluated using the top-down BACT approach. An SCR will be installed and operated to control NO_X emissions from NG-firing in the GT with or without the DB firing.

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7.3.1 Background on Pollutant Formation

There are different ways that NO_X emissions can be formed in a GT or DB. The literature refers to five (5) primary "types" of NO_X: thermal NO_X, prompt NO_X, NO_X from N_2O intermediate reactions, fuel NO_X, and NO_X formed through reburning. The three most important mechanisms are thermal NO_X, prompt NO_X, and fuel NO_X.[62] For NG-fired units, most NO_X is thermal NO_X.

Thermal NO_X is formed mainly via the Zeldovich mechanism where the N_2 and O_2 molecules in the combustion air react to form nitrogen monoxide (NO).[63] Most thermal NO_X is formed in high temperature flame pockets downstream from the fuel injectors.[64] Temperature is the most important factor, and at combustion temperatures above 2,370°F, thermal NO_X is formed readily.[65] Therefore, reducing combustion temperature is a common approach to reducing NO_X emissions.

Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as hydrogen cyanide (HCN), N, and NH are oxidized to form NO_X.[66] The contribution of prompt NO_X to overall NO_X is relatively small but increases in low- NO_X combustor designs. Prompt NO_X formation is also largely insensitive to changes in temperature and pressure.[67]

Fuel NO_X forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since NG contains little fuel bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from NG-fired combustion turbines.[68]

7.3.2 Step 1 – Identification of Potential Control Technologies

NO_X emissions can be reduced by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Post-combustion control technologies use various strategies to chemically reduce NO_X to N_2 with or without the use of a catalyst. Control options are provided in Table 7-5.

[62] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[63] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[64] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, July 1998, and AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*, April 2000.

[65] U.S. EPA, Clean Air Technology Center, *Technical Bulletin: Nitrogen Oxides (NO_x), Why and How They are Controlled*, EPA 456/F-99-006R. November 1999.

[66] U.S. EPA, Emission Standards Division, *Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines*, EPA-453/R-93-007. January 1993.

[67] Ibid.

[68] Ibid.

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Table 7-5. Potential NO_X Control Technologies for NGCC

Pollutant	Type	Control Technologies
NO_X	Combustion Control	DLN Combustion Technology Good Combustion Practices
	Post-Combustion Control	Multi-Pollutant Catalyst (EM_X™/$SCONO_X$™/ METEOR™) SCR SNCR

7.3.2.1 DLN Combustors

DLN combustor technology is used during NG combustion. DLN combustors premix air and a lean fuel mixture prior to injection into the combustion turbine which significantly reduces peak flame temperature and thermal NO_X formation from NG combustion. Conventional combustors are diffusion controlled where fuel and air are injected separately.

7.3.2.2 Good Combustion and Operating Practices

GCOP allow the equipment to operate as efficiently as possible. The air-to-fuel ratio is one of the primary indicators of efficient combustion. Good combustion practices involve the monitoring of the air to fuel ratio to ensure the most efficient combustion. Modern turbine control systems enhance combustion efficiency by automatically adjusting operating parameters through computer-based technology.

7.3.2.3 EM_X™ / $SCONO_X$™/METEOR™

EM_X™ is described in detail in Section 7.1.2.2.

Estimates of control efficiency for a $SCONO_X$ system vary depending on the pollutant controlled. California Energy Commission reports a CE of 78% for NO_X reductions down to 2.0 ppm, and even higher NO_X reductions down to 1 ppm for some designs.[69] It should be noted that there are no RBLC entries for comparable combined cycle combustion turbine facilities with BACT limits below 2.0 ppm, and those facilities with limits of 2.0 ppm are all equipped with SCR, suggesting that $SCONO_X$ is, at best, no more effective at reducing NO_X emissions than SCR systems.

The METEOR™ catalyst is similar to standard SCR systems, using ammonia to reduce NO_X emissions. An equivalent level of control to standard SCR is achieved.[70]

7.3.2.4 SCR

SCR systems are used extensively in power generation applications including coal, oil, and combined cycle power plants. SCR is a post-combustion emissions control technique whereby aqueous ammonia is vaporized and injected into the combustion exhaust gases before they pass through a catalyst bed. In the presence of the catalyst, NO_2 and NO react with oxygen and ammonia to produce diatomic nitrogen and water.

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[69] California Energy Commission, *Evaluation of Best Available Control Technology*, Appendix 8.1E, page 8.1E-6.

[70] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 15-16.

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The basic chemical reactions are as follows:

$$2\ NO + 2\ NH_3 + ½\ O_2 \rightarrow 2\ N_2 + 3\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Small amounts of ammonia that are not consumed in the reaction result in low levels of ammonia stack emissions, known as ammonia slip. The performance of an SCR system depends primarily on the temperature of the exhaust gas as it passes through the catalyst. Although catalyst formulations have provided a continuum of temperature ranges, these are typically described by three temperature ranges for optimal NO_X reduction. A "normal" catalyst operates well at approximately 650°F, a "mid-range" catalyst operates well between 800 and 900°F, and a "hot" catalyst (generally zeolite based) can operate above a temperature of 1,100°F, although the effectiveness of NO_X removal declines as a function of the exhaust gas temperature. Conventional vanadium/titanium catalysts are commonly used in SCR applications and have an optimal operating temperature in the 600 to 750°F range. The application of SCR on the combined cycle units can utilize a conventional catalyst which is located downstream of the GT itself, within the tube banks at an appropriate temperature region, near the 600-700°F range.

The catalyst used is typically stacked vertically with gas flow horizontally through the catalyst face. The catalyst has a much smaller pitch due to the limited particulate and plugging concerns and does not deactivate as rapidly due to minimal catalyst poisons in the flue gas.

7.3.2.5 SNCR

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia with NO_X. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or ammonia is injected into the combustion gas path to reduce the NO_X to nitrogen and water. The overall reaction schemes for both urea and ammonia systems can be expressed as follows:

$$CO(NH_2)_2 + 2\ NO + ½\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$
$$4\ NH_3 + 6\ NO \rightarrow 5\ N_2 + 6\ H_2O$$

Typical removal efficiencies for SNCR range from 30 to 50 percent and higher when coupled with combustion controls.[71] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000°F. Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_X.

7.3.3 Step 2 – Elimination of Technically Infeasible Control Options

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest CE of the option would result in an emission level that is higher than any applicable regulatory limits.

[71] U.S. EPA, Clean Air Technology Center*, Air Pollution Control Technology Fact Sheet: Selective Non -Catalytic Reduction (SNCR)*, EPA-452/F-03-031.

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7.3.3.1 DLN Combustion Technology Feasibility

DLN combustion technology is technically feasible for NG combustion and the proposed GT will have DLN combustors. DLN combustion technology is included in the following BACT steps but represents part of the base case for NO_X performance as it is inherent in the operation of the combustion systems. As previously discussed, DLN cannot be used at low loads, during which the combustor operates in diffusion mode. Therefore, DLN is technically infeasible at low loads.

7.3.3.2 Good Combustion and Operating Practices Feasibility

Good combustion practices are technically feasible. The proposed NGCC will be equipped with automated computer-based control systems capable of adjusting operating parameters to ensure that all GT and DB systems, including those intended to minimize pollutant formation, operate as effectively and efficiently as possible.

7.3.3.3 EM$_X$™ / SCONO$_X$™/METEOR™ Technology Feasibility

As summarized by Illinois EPA in their project summary for the Jackson Energy Center PSD permit, the EM$_X$™/SCONO$_X$™ catalyst system has operated successfully on several smaller, NG-fired combined cycle units, but there are engineering challenges with scaling up this technology for use on large gas turbines.[72,73] Therefore, EM$_X$™/SCONO$_X$™ is determined to be technically infeasible.

The METEOR™ catalyst technology, developed and patented by Siemens Energy Inc., is currently only in use on one 320 MW Siemens/Westinghouse 501G combustion turbine installed in November 2015.[74,75] A review of the RBLC database for turbines similar to the proposed units did not return any units that use the METEOR™ catalyst technology. As there is limited commercial operating experience with the METEOR™ catalyst and it does not achieve greater reduction than SCR, the METEOR™ technology option is not considered a technically feasible control option for purposes of BACT.

7.3.3.4 SCR Feasibility

The optimal catalyst temperature for the operation of SCR is in the range of 480°F to 800°F, but with recent advances in catalyst materials and design, the temperature can be as high as 1,100°F.[76] SCR is regularly used on combined cycle units, since the exhaust from combined cycle operations has had heat removed, and the normal temperature is within the effective range for SCR. Thus, SCR is technically feasible for the proposed NGCC.

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[72] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B pages 14.

[73] National Energy Technology Laboratory, *8.7. Nitrogen Oxides (NO_x) Emissions*. Available online at https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/nitrogen-oxides. Accessed August 15, 2024.

[74] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of NO_X, Attachment B page 16.

[75] Siemens Energy and Cormetech, *Capital and O&M Benefits of Advanced Multi-Function Catalyst Technology for Combustion Turbine Power Plants,* Power Gen 2015, page 2.

[76] Mitsubishi Hitachi Power Systems, *Overview of SCR Technology and Retrofitting of SCR's to Comply with Upcoming NO_x BARCT Standards for Electric Power Generating Units*, Robert McGinty, presentation for SCAQMD AWMA Annual Regional Meeting, ca. 2017.

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7.3.3.5 SNCR Feasibility

The temperature range required for effective operation of this technology is 1,600 to 2,000°F. This is above the peak exhaust temperature for the proposed NGCC.[77] SNCR is eliminated as a technically feasible option for control of NO_X emissions from the NGCC.

7.3.4 Step 3 – Rank Remaining Control Technologies

The potentially feasible control technologies include SCR, DLN combustors, and good combustion practices. Table 7-6 shows the rank for each of these control technologies.

Table 7-6. Rank Remaining NO_X Control Technologies – NGCC

Control Technology	Technically Feasible	Estimated Efficiency
SCR	Yes	~90%
DLN Combustion Technology	Yes	GT Design
GCOP	Yes	GT/DB Design

7.3.5 Step 4 – Evaluation of Most Stringent Control Technologies

SCR is the highest ranking potentially feasible control technology. As summarized in Step 5, KU is proposing use of SCR with DLN and GCOP as BACT (as feasible for operating load). No additional evaluation of emission control is needed.

7.3.6 Step 5 – Selection of BACT

7.3.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

As detailed in Section 5 of this application, the proposed NGCC will be subject to NSPS KKKK, which includes a NO_X emission standard of 15 ppmvd at 15% O_2 on a 4-hour average basis, excluding startup and shutdown. The NSPS Subpart KKKK limit serves as the floor for the allowable NO_X BACT limit.

7.3.6.2 Summary of RBLC Review

KU reviewed the results of the RBLC search and noted that there are no RBLC entries for comparable NGCC operations with emission limits lower than KU's proposed BACT limits. Detailed RBLC search results tables are provided in **Appendix D**.

7.3.6.3 NO_X BACT Limit Selection – Steady-State Operation

KU is proposing BACT for the NGCC as the use of SCR technology, DLN, and GCOP. As mentioned, DLN will be used as feasible depending on turbine load. KU is proposing a BACT limit for NO_X of 2.0 ppmvd, corrected to 15% O_2, applied as a 30-day rolling average, excluding periods of SU/SD. Compliance will be demonstrated via NO_X CEMS.

[77] U.S. EPA, Clean Air Technology Center, Air Pollution Control Technology Fact Sheet: Selective Non-Catalytic Reduction (SNCR), EPA-452/F-03-031.

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7.4 PM/PM_{10}/$PM_{2.5}$ BACT Evaluation for NGCC

The following sections present a review of pollutant formation and possible control technologies for particulate matter emissions from the NGCC. Air pollution control strategies are evaluated using the top-down BACT approach. Highly efficient GTs, such as the one proposed for the NGCC EGU Project inherently emit low levels of particulate matter without add-on control devices. The underlying design includes the use of low sulfur fuels and inlet filters along with good combustion practices to mitigate particulate matter emissions from NG-firing in the GT and DBs.

7.4.1 Background on Pollutant Formation

PM/PM_{10}/$PM_{2.5}$ emissions from gas combustion result primarily from incomplete combustion and also ash and sulfur in the fuel.[78] Combustion of NG generates low PM emissions in comparison to other fuels due to the low ash and sulfur contents of this fuel. Regardless of the type of fuel combusted, filterable PM generally includes airborne PM which passes through the inlet air filters, inert solids in the fuel supply, and metallic rust or oxidation products.[79]

7.4.2 Step 1 – Identification of Potential Control Technologies

The following are controls that reduce PM/PM_{10}/$PM_{2.5}$:

- Multicyclone,
- Wet Scrubber,
- ESP,
- Baghouse,
- Inlet air filters,
- Low-sulfur fuel, and
- Good combustion and operating practices.

Multicyclones, wet scrubbers, ESPs, and baghouses are all available control technologies for the reduction of PM/PM_{10}/$PM_{2.5}$. However, none of these technologies have ever been installed on a commercial combustion turbine. Therefore, these technologies will not be evaluated further in the BACT analyses.

7.4.2.1 Inlet Air Filters

Inlet air filters reduce the amount of solid particulate matter entering the turbine combustion chamber. Given that a portion of the PM/PM_{10}/$PM_{2.5}$ emissions from the turbine are generated from solids entrained in the combustion air, the use of inlet air filters can reduce PM/PM_{10}/$PM_{2.5}$. As inlet air filters are standard equipment for combustion turbines, the use of inlet air filters is considered part of the base case for the NGCC.

7.4.2.2 Low-Sulfur Fuels

Combusting pipeline-quality NG with an inherently low sulfur content reduces particulate emissions compared to other available fuels as there is less potential to form solid sulfates and other sulfur byproducts.

[78] AP-42, Chapter 3, Section 1, *Stationary Gas Turbines*. April 2000.

[79] Wien S, Beres J, Richani B, General Electric Company. *Air Emissions Terms, Definitions and General Information*.; 2005. https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-4249-air-emissions-terms-definitions-general-information.pdf

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7.4.2.3 Good Combustion and Operating Practices

Good combustion and operating practices will minimize the formation of $PM/PM_{10}/PM_{2.5}$ emissions due to incomplete combustion. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios and periodic tuning.

7.4.3 Step 2 – Elimination of Technically Infeasible Control Options

Due to the low particulate concentration in the exhaust gas, add-on $PM/PM_{10}/PM_{2.5}$ controls would not provide any significant degree of emission reduction for the combustion turbines and are therefore not considered further in this analysis.[80] The remaining control options (inlet air filters, low sulfur fuels, and good combustion practices) are technically feasible for the NGCC and are evaluated further in the BACT analysis.

7.4.4 Step 3 – Rank of Remaining Control Technologies

Of the control technologies available for $PM/PM_{10}/PM_{2.5}$ emissions, the options technically feasible for the turbines are shown in Table 7-7**.**

Table 7-7. Remaining Particulate Matter Control Technologies for NGCC

Control Technology	Technically Feasible for NGCC	Emissions Reduction
Inlet Air Filters	Yes	Reduction Varies
Low Sulfur Fuel	Yes	Reduction Varies
Good Combustion and Operating Practices	Yes	Reduction Varies

7.4.5 Step 4 – Evaluation of Most Stringent Control Technologies

Good combustion and operating practices with NG and low sulfur fuel, along with inlet air filters, are the most stringent $PM/PM_{10}/PM_{2.5}$ controls that are technically feasible options. KU is proposing to use low-sulfur fuels, inlet air filters, and good combustion practices, as the most effective means for reducing $PM/PM_{10}/PM_{2.5}$ emissions from the NGCC.

7.4.6 Step 5 – Selection of BACT

BACT for $PM/PM_{10}/PM_{2.5}$ emissions are determined to be the use of low-sulfur fuels, inlet air filters, and good combustion practices. As the proposed combustion turbines are not subject to any NSPS or NESHAP rule which limit PM emissions, there is no floor for the allowable BACT limit for PM.

7.4.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The proposed GT and DBs are not subject to any NSPS or NESHAP rule which limit PM emissions; therefore, there is no floor for the allowable BACT limit for PM. Unlike the GT, the HRSG with DBs will be subject to a PM emission limit under 401 KAR 59:015, which is 0.10 lb PM/MMBtu.

[80] Application No. 17040013, *Project Summary for a Construction Permit Application from Jackson Generation, LLC, for an Electrical Generating Facility in Elwood, Illinois*, issued by the Illinois EPA for the public comment period beginning on September 21, 2018. Discussion related to selection of BACT for emissions of particulates, page 43.

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7.4.6.2 Summary of RBLC Review

EPA's RBLC database was reviewed to determine what has been established as a BACT emission requirement for comparable operations. Table 7-8 includes RBLC search results that are more stringent than the proposed limit for natural gas in Step 5 (equivalent to 0.005 lb/MMBtu). Detailed RBLC search results are presented in **Appendix D.**

Table 7-8. Particulate Matter RBLC Entries for NGCC

RBLC ID	Facility	Permit Date	Permitted PM Limit (w/o DB)	Permitted PM Limit (w/ DB)	Units	Averaging Period
MI-0427	Filer City Station	11/17/2017	0.0025 0.0066		lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Not indicated
PA-0309	Lackawanna Energy Center	12/23/2015	0.003 0.0059		lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Not indicated
VA-0325	Greensville Power Station	6/17/2016	0.003	0.0039	lb/MMBtu	N/A (stack test)
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	11/7/2017	0.0036		lb/MMBtu (PM,$PM_{10,2.5}$)	Not indicated
PA-0306	Westmoreland Generating Facility	2/12/2016	0.0039	0.0039	lb/MMBtu (w/ DB)	Not indicated
MI-0442	Thomas Township Energy, LLC	8/21/2019	0.0034 0.006		lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Hourly max
IL-0129	CPV Three Rivers Energy Center	7/30/2018	0.0037 0.0069		lb/MMBtu (PM_{filt}) lb/MMBtu (PM_{10})	3 Hour
VA-0335	Panda Stonewall, LLC	12/18/2020	0.0037		lb/MMBtu ($PM_{2.5}$)	Not indicated
IL-0130	Jackson Energy Center	12/31/2018	0.0026 0.0042	0.0026 0.0042	lb/MMBtu (PM) lb/MMBtu ($PM_{10,2.5}$)	3 Hour
AL-0328	Alabama Power Company Plant Barry	11/9/2020	0.004	0.004	lb/MMBtu ($PM_{10,2.5}$)	3 Hour
CT-0161	Lake Road Energy Center	6/30/2017	0.044 0.0044	0.005 0.005	lb/MMBtu (PM_{10}) lb/MMBtu ($PM_{2.5}$)	Not indicated
IN-0365	Maple Creek Energy LLC	6/19/2023	0.0049		lb/MMBtu	N/A
OH-0366	Clean Energy Future - Lordstown, LLC	8/25/2015	0.0068	0.0049	lb/MMBtu ($PM_{10,2.5}$)	Not indicated

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In addition to the more stringent emission limits above, there are also over 20 approved limits for NG in **Appendix D** that are equivalent to or greater than the NG limit proposed for Brown Station. Since particulate emissions from NG combustion are partially driven by the sulfur and ash content of the natural gas, variability in natural gas emission limits is expected based on the composition of the available fuel.

7.4.6.3 Proposed $PM/PM_{10}/PM_{2.5}$ BACT Limit

Steady-state generation of PM emissions from the NGCC is expected to be negligible. KU is proposing a BACT limit of 0.005 lb/MMBtu for $PM/PM_{10}/PM_{2.5}$ at 100% load. This limit will apply at all times. KU is proposing that compliance be demonstrated using performance testing. The proposed BACT limit is based on the vendor supplied information, at a maximum inlet sulfur content of 0.5 gr/100 scf.

7.5 H_2SO_4 BACT Evaluation for NGCC

7.5.1 Background on Pollutant Formation

H_2SO_4 emissions result from the reaction of SO_3, formed from the oxidation of SO_2 emissions, with water. Uncontrolled H_2SO_4 emissions depend on the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. H_2SO_4 emissions are not dependent upon combustion turbine properties such as size or burner design.

7.5.2 Step 1 – Identification of Potential Control Technologies

The available control options identified for H_2SO_4 are listed in Table 7-9.

Table 7-9. Potential H_2SO_4 Control Technologies for NGCC

Pollutant	Control Technologies
H_2SO_4	FGD Scrubber Dry Sorbent Injection Low-Sulfur Fuel Good Combustion Practices

Flue Gas Desulfurization scrubbers and Dry Sorbent Injection are both available control technologies for the reduction of H_2SO_4 emissions. However, none of these technologies have ever been installed on a commercial combustion turbine. Therefore, these technologies will not be evaluated further in the BACT analyses.

7.5.2.1 Low-Sulfur Fuel

The use of low-sulfur fuels in the NGCC decreases the amount of sulfur in the system which ultimately decreases emissions of sulfur compounds including SO_2, SO_3 and H_2SO_4 mist. KU will use pipeline quality NG containing a maximum sulfur content of 0.5 gr S/100 scf.

7.5.2.2 Good Combustion Practices

Operation and maintenance of the equipment in accordance with good air pollution control practices and with good combustion practices results in efficient combustion of fuel, which in turn results in reduced usage of fuel and associated emissions of H_2SO_4 mist.

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7.5.3 Step 2 – Elimination of Technically Infeasible Control Options

Add-on controls are not available for the reduction of H_2SO_4 emissions from the NGCC. The use of low-sulfur fuels and good combustion practices are technically feasible.

7.5.4 Step 3 – Rank Remaining Control Technologies

The remaining control technologies are the use of low-sulfur fuel and good combustion practices, the base case for BACT.

7.5.5 Step 4 – Evaluation of Most Stringent Control Technologies

KU will implement both low-sulfur fuels and good combustion practices to reduce H_2SO_4 emissions from the NGCC.

7.5.6 Step 5 - Selection of BACT

7.5.6.1 Summary of Applicable Limits from NSPS/NESHAPs/State Rules

The proposed NGCC is not subject to any NSPS or NESHAP standard for H_2SO_4, and thus there is no floor of allowable H_2SO_4 BACT limits.

7.5.6.2 Proposed H_2SO_4 BACT Limit

Based on review of the RBLC search results (**Appendix D**) and recently issued permits for similar sized power plants, the sulfur content ranges from 0.2 to 5 gr S/100 scf NG, with separate limits for varying averaging periods. In addition, as shown in **Appendix D**, the RBLC data search shows that no add-on controls are required for NG-fired NGCC generating units to control H_2SO_4 emissions.

KU proposes the use of low-sulfur fuels and good combustion practices as BACT for H_2SO_4 emissions. NG combusted in the NGCC will contain no more than 0.5 gr S/100 scf, which is based on the gas supply that is available to the facility.

7.6 GHG BACT Evaluation for NGCC

This section contains a high-level review of pollutant formation and possible control technologies for the NGCC system. The vast majority of GHG emissions, on a CO_2e, from combustion turbines are CO_2. Emissions of CH_4 from turbines are typically extremely low.[81] N_2O emissions in the turbine exhaust are generally less than 1 ppm during startup, potentially rising to several ppm during transient operation, which is insignificant compared to the CO_2 emissions from the turbine, even on a CO_2e basis. Therefore, given that CO_2e emissions from the turbine are made up of almost entirely CO_2, KU is presenting a GHG BACT analysis for CO_2 only.

[81] *White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units, April 21, 2022.* Prepared by U.S. EPA. Draft White Paper: Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Combustion Turbine Electric Generating Units

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7.6.1 Background on Pollutant Formation

CO_2 production from combustion occurs by a reaction between carbon and oxygen in the air and proceeds stoichiometrically (for every 12 pounds of carbon burned, 44 pounds of CO_2 is emitted).[82] CH_4 can be emitted when a fossil fuel is not burned completely in combustion.[83] The last primary component for calculating GHG emissions (in addition to CO_2 and CH_4) is N_2O. N_2O formation is limited during complete gas combustion, as most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.[84]

7.6.2 Step 1 – Identification of Potential Control Technologies

KU reviewed the large body of information on GHG emissions from combustion turbines compiled from various rulemakings, such as the NSPS Subpart TTTT and TTTTa preambles. The RBLC lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These results are included in **Appendix D**, detailing emission levels proposed for similar types of emissions units. Based on the RBLC search, no add-on control methods for GHGs have been deemed BACT for any facility. Many of the RBLC entries list a variant of good combustion practices, efficient operation, state-of-the-art technology, or low emitting fuels (e.g., pipeline-quality NG).

Table 7-10 lists potential CO_2 control strategies that were considered as part of this BACT analysis.

Table 7-10. Potential GHG Control Technologies for NGCC

Pollutant	Control Technologies
GHG	CCS Efficient NGCC Operation and Good Combustion Practices

These control technologies are discussed in the following sections.

7.6.2.1 Carbon Capture and Sequestration/Storage

CCS involves (1) "capturing" and separating the CO_2 from the exhaust of the emission source; (2) transferring the CO_2 to an appropriate injection site; **and** (3) sequestering/storing the CO_2 at a suitable site.

The first phase in CCS is to separate and capture the CO_2 gas from the exhaust stream, and then to compress the CO_2 to a supercritical condition.[85] Since most storage locations for CO_2 are greater than 800 meters deep, where the natural temperatures and pressures are greater than the critical point for CO_2, to inject CO_2 to those depths requires pressurizing the captured CO_2 to a supercritical state.

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[82] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

[83] AP-42, Chapter 1, Section 4, *Natural Gas Combustion*. July 1998.

[84] *NC Greenhouse Gas (GHG) Inventory Instructions for Voluntary Reporting, November 2009*. Prepared by the North Carolina Division of Air Quality. https://files.nc.gov/ncdeq/Air%20Quality/inventory/forms/GHG_Emission_Inventory_Instructions_Nov2009_Voluntary.pdf

[85] Supercritical means that the CO_2 has properties of both a liquid and a gas. Supercritical CO_2 is dense like a liquid but has a viscosity like a gas. For additional details see https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs

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CO_2 capture can be performed via four main methods: absorption, adsorption, membranes, and cryogenic separation. The choice of the precise process varies with the properties of the exhaust stream. CO_2 separation has been well demonstrated in the oil and gas industries, but the characteristics of those streams are very different from a combustion turbine system exhaust. Most combustion tests and projects have been on exhaust streams from coal combustion, which has more highly concentrated CO_2 than exhaust from NG combustion, or on NG combined cycle systems.

Once separated, CO_2 must be compressed to supercritical conditions for transport and storage. The CO_2 could be compressed to supercritical either before or after transport. The technology needed to compress CO_2 to supercritical conditions is available; however, specialized technologies require high operating energy requirements. It is important to understand that there are technical challenges with compressing the expected volume of CO_2 generated from the GT. To do this step, KU would be required to co-locate a new chemical manufacturing facility.

For phase two, CO_2 would be transported to a repository. Transport options could include pipeline or truck. Specialized designs may be required for CO_2 pipelines, particularly if supercritical CO_2 is being transported. Transport of CO_2 by pipeline is a demonstrated technology, but currently most CO_2 pipelines are in rural areas. Obtaining right-of-way in developed areas is difficult.

Various CO_2 storage methods have been proposed, though only geologic storage is achievable currently. Geologic storage involves injecting CO_2 into deep subsurface formations for permanent storage. Typical storage locations would be deep saline aquifers as well as depleted or un-mineable coal seams. Captured CO_2 could also potentially be used for enhanced oil recovery via injection into oil fields.

7.6.2.2 Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

As the baseline of most analyses, pollutant formation can be most cost-effectively minimized by efficient turbine design and good combustion, operating, and maintenance practices.

Within combustion units, operators can control the localized peak combustion temperature and combustion stoichiometry to achieve efficient fuel combustion. Outside of the unit, energy loss can be minimized by providing sufficient insulation to the combustion units and associated duct work.

For the purposes of this GHG control technology assessment, it is important to note that good operating practices includes periodic maintenance by abiding by an O&M plan. Maintaining the combustion units to the designed combustion efficiency and operating parameters is important for energy efficiency related requirements and efficient operation.

7.6.3 Step 2 – Elimination of Technically Infeasible Control Options

7.6.3.1 Carbon Capture, Transport, and Storage

CCS involves cooling, separation and capture of CO_2 from the flue gas prior to the flue gas being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components (carbon capture and compression, transport, and storage) must be technically feasible.

<u>Carbon Capture</u>

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In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects).[86] Currently, only two options appear to be feasible for capture of CO_2 from the flue gas from the turbine system: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents."[87]

A review of the U.S. Department of Energy's (DoE) National Energy Technology Laboratory's (NETL) research and development awards related to post-combustion capture of CO_2 indicates that moving from pilot scale tests at coal-fired power plants to large-scale commercial operations remains a focus; however, the existence of several Front End Engineering Design (FEED) studies indicates that commercial implementation is beginning to move forward.[88] For example, a FEED study is underway for a commercial-scale carbon capture facility retrofitted at the Delta Energy Center in Pittsburg, CA, capable of capturing 2.4MM tons of CO_2 per year.[89]

Another pilot-scale study is underway for a 1.7 MM ton/yr CO_2 capture project at the Louisville Gas and Electric Kentucky Utilities Cane Run #7.[90] That project is planned to study methods for collecting CO_2 from the flue gas stream; however, there are no plans to "transport" in the traditional pipeline sense. The plan is to see if some of the captured CO_2 can be made commercial grade and potentially sold to interested parties. If none are available, the slip stream would be re-released.

Although FEED studies indicate heightened interest in exploring potential implementation opportunities for CCS, KU is aware of only one successful CCS deployment on a combined cycle combustion turbine facility. The Bellingham Energy Center captured CO_2 from a slipstream (i.e., a portion of the turbine exhaust stream) for use in the food industry and operated from 1991 to 2005.[91] Additionally, a planned 2,000 MW NG combined cycle power plant with CCS is expected to come online towards the end of the 2020s, but construction is not expected to start for several years at least.[92]

Presuming carbon capture is feasible, prior to sending the CO_2 stream to the appropriate storage site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia).

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[86] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, Section III, pages. 27-52. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[87] Herzog, Meldon, Hatton, Advanced Post-Combustion CO_2 Capture, April 2009, page 7. https://sequestration.mit.edu/pdf/Advanced_Post_Combustion_CO2_Capture.pdf

[88] Website reviewed June 2024: https://netl.doe.gov/node/2476?list=Post-Combustion%20Capture

[89] *Front-End Engineering Design for a CO_2 Capture System at Calpine's Delta Energy Center,* U.S. Department of Energy, National Energy Technology Laboratory, Project Review Meeting Presentation for Project Number FE0032149, start date February 1, 2022.

[90] *CO_2 Capture at Louisville Gas & Electric Cane Run Natural Gas Combined Cycle Power Plant,* U.S. Department of Energy, National Energy Technology Laboratory, Project Review Meeting Presentation for Project Number FE0032223, start date December 22, 2022. https://netl.doe.gov/sites/default/files/netl-file/24CM/24CM_PSCC_5_Berger.pdf

[91] *Greenhouse Gas Mitigation Measures: Carbon Capture and Storage for Combustion Turbines Technical Support Document,* U.S. Environmental Protection Agency, Office of Air and Radiation, May 23, 2023. (pp. 23)

[92] *Company Responds as PSC green lights siting for future plant in Doddridge County*, West Virginia Metro News, May 5, 2024. https://wvmetronews.com/2024/05/05/psc-green-lights-siting-certificate-for-cpvs-future-plant-in-doddridge-county/

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The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[93] The auxiliary power load could be handled by installation of a separate system to solely support CO_2 compression, or alternatively be supported by reducing the available energy for sale, relying on the energy generating systems to instead meet the power needs of the compression system. This is often referred to as an "energy penalty" for operation of the CO_2 compression system, and in effect can reduce the net CO_2 reduction of the CCS system.

Carbon Transport

The next step in CCS is the transport of the captured and compressed CO_2 to a suitable location for storage. This would typically be via pipeline. Pipeline transport is an available and demonstrated, although costly, technology. Short CO_2 pipelines have been constructed from power plants to proposed injection wells. However, these pipelines are dedicated use for the power plants and are unavailable for other industrial sites.

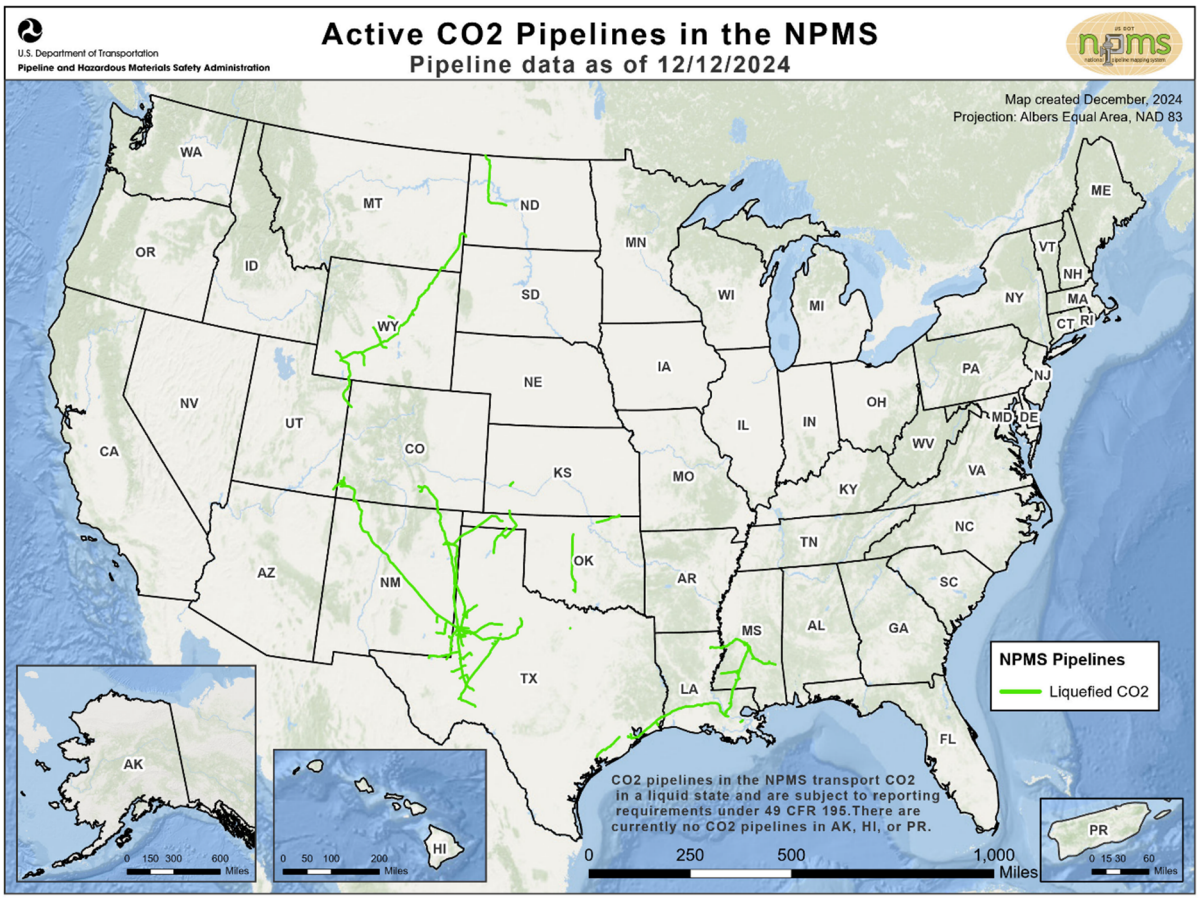
Since there are no other CO_2 pipelines in the area, as shown in Figure 7-1, KU would need to construct a CO_2 pipeline to a storage location if it were to pursue carbon sequestration as a CO_2 control option.[94] While it may be technically feasible to construct a CO_2 pipeline, considerations regarding the land use and availability need to be made. For the purposes of this analysis, it is conservatively assumed that a shortest distance pipeline can be built from a potential sequestration site to a potential carbon storage location. Realistically, a longer pipeline would be required to address land use and right-of-way considerations.

[93] *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010, page 29. https://www.energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf

[94] *Active CO_2 Pipelines in the NPMS,* U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration National Pipeline Mapping System, March 11, 2024. https://www.npms.phmsa.dot.gov/Documents/NPMS_CO2_Pipelines_Map.pdf

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Figure 7-1. NPMS Active CO_2 Pipelines



Carbon Storage

Capture of the CO_2 stream and transport are not sufficient control technologies by themselves but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed as follows:

- Enhanced Oil Recovery (EOR): EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO_2 would be stored in the depleted oil field.
- Saline Aquifers: Deep saline aquifers have the potential to store post-capture CO_2 deep underground below impermeable cap rock.
- Un-Mineable Coal Seams: Additional storage is possible by injecting the CO_2 into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releasing methane.

There are additional methods of sequestration such as direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be

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technologically available at a small-scale, the limiting factor is the availability of a mechanism for KU to permanently store the captured CO_2.

NETL's Carbon Capture and Storage Database provides a summary of potential storage locations.[95] According to the database, the nearest potential sequestration sites where test wells were drilled are the Sugar Creek Field and the Western Kentucky CO_2 Test well. Kentucky has a Class II well program that covers the underground injection of CO_2 for purposes other than permanent storage.[96] However, the Class VI injection well permitting requirements for a commercial-scale CCS operation would reside with EPA as Kentucky has not been granted primacy for Class VI injection well permit issuance.[97] No EPA-issued Class VI injection well permits have been issued for a Kentucky underground injection site.[98]

Elimination of CCS as Technically Feasible

KU has concluded that CCS technology is not technically feasible at this time, based on the following key considerations:

- Solvent-based carbon capture systems have not been demonstrated for a large combined cycle combustion turbine;
- There are no existing or planned CO_2 pipelines within a reasonable distance from the proposed project; and
- There are no existing or planned commercially available sequestration sites within a reasonable distance from the proposed project.

7.6.3.2 Efficient Turbine Operation and Good Combustion, Operating, and Maintenance Practices

Efficient turbine operation coupled with good combustion, operating, and maintenance practices are a potential control option for optimizing the fuel efficiency of the combustion turbines. Combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the turbine systems are sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.

Another option for efficiently generating electricity is to deploy an aeroderivative combustion turbine in place of a heavy-duty frame-class combustion turbine. Aeroderivative units offer improved efficiency and lower maintenance costs. However, as discussed previously, many of the historical disadvantages of frame-class turbines have been improved in recent years, and the much higher single-unit generating capacity offered by frame-class turbines is necessary for the technical and economic feasibility of the proposed project. Mandating the use of multiple smaller aeroderivative turbines in place of the proposed frame-class turbine would require a complete redesign of the proposed facility and would require KU to reexamine the goals, objectives, and purpose of the facility. Considering EPA's stance on defining the source, as explained

[95] Carbon Capture and Storage Database maintained by the NETL, accessed July 2021 at https://www.netl.doe.gov/coal/carbon-storage/worldwide-ccs-database

[96] https://eec.ky.gov/Natural-Resources/Oil-and-Gas/Programs/Pages/underground-injection-control-wells.aspx

[97] https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0

[98] https://udr.epa.gov/ords/uicdr/r/uicdr_ext/uicdr-pub/map

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above, this would clearly redefine the source. Consequently, the use of aeroderivative turbines is not considered as a component of BACT.

Therefore, efficient turbine operation coupled with good combustion, operating, and maintenance practices is evaluated further for CO_2 BACT purposes.

7.6.4 Step 3 – Rank Remaining Control Technologies

Efficient turbine operation and good combustion, operating, and maintenance practices are the only remaining control methods. Reduction efficiency is not applicable for this control method.

7.6.5 Step 4 – Evaluation of Most Stringent Control Technologies

As efficient turbine operation and good combustion, operating, and maintenance practices are the only remaining control method, no ranking of control methods is required.

7.6.6 Step 5 – Selection of BACT

As summarized in detail Section 5.1.10of this application, the proposed NGCC will be subject to Subpart TTTTa. The NSPS includes CO_2 emission limits for combustion turbines based on the annual capacity factor of the turbines, where capacity factor in this case means net electric sales as a percentage of potential electric output. The CO_2 emission limits are as follows:

- Base load CT:
  - Phase 1 (prior to January 2032): 800 to 1,120 lb CO_2/MWh-g energy output,[99] based on combined cycle operation
  - Phase 2 (after December 2031): 100 to 150 lb CO_2/MWh-g energy output, as determined by 40 CFR §63.5525a, based on CCS
- Intermediate load CT:
  - 1,170 - 1560 lb CO_2/MWh-g energy output, as determined by 40 CFR §63.5525a, based on highly efficient simple-cycle generation
- KU must operate and maintain the GT, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if the facility is using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of your EGU. [40 CFR §60.5525a(b)]

7.6.6.1 Summary of RBLC Review

BACT determinations for similar combined cycle generating units denote energy efficiency, good design and good combustion practices as BACT. Post-combustion capture and sequestration of CO_2 has not been required. BACT limits for turbine units can be found expressed in terms of lb/MMBtu (i.e., the basis of the NSPS Subparts TTTTa CO_2 emission limit), lb CO_2/MWh-n, lb CO_2/MWh-g, Btu/kWh, lb/hr, or tons, typically with a 12-month rolling averaging period. The following RBLC search results include limits that are lower than the proposed BACT limit of 815 and 925 lb/MWh-g with and without DB firing, respectively.

[99] In accordance with 40 CFR 60.5520a(c), the emission limits should be based on gross energy output unless the owner or operator of a stationary combustion turbine petitions the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard.

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Table 7-11. CO_2 RBLC Entries for Operating NG-Fired NGCC

RBLC ID	Facility	Permit Date	Permitted CO_2 Limit (w/o DB)	Permitted CO_2 Limit (w/ DB)	Units	Averaging Period
IN-0365	Maple Creek Energy LLC	6/19/2023	726		lb/MWh-g	12-mo Rolling
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	11/7/2017	775	775	lb/MWh	12-mo Rolling
MI-0435	Belle River Power Plant	7/16/2018	794		lb/MWh	12-mo Rolling
MI-0423	Indeck Niles, LLC	1/4/2017	802		lb/MWh	Not indicated
MI-0433	MEC North & MEC South	6/29/2019	806		lb/MWh	12-mo Rolling
CT-0158	CPV Towantic Energy Center	11/30/2015	809		lb/MWh	12-mo Rolling
WV-0032	Brooke County Power Plant	9/18/2018	829	829	lb/MWh	Not indicated
OH-0366	Clean Energy Future - Lordstown, LLC	8/25/2015	833	833	lb/MWh	Not indicated
OH-0372	Oregon Energy Center	9/27/2017	833	833	lb/MWh	Not indicated
NJ-0085	Middlesex Energy Center	7/19/2016	888	888	lb/MWh-g	12-mo Rolling
VA-0325	Greensville Power Station	6/17/2016	812-890	812-890	lb/MWh-n	Annual (1-6 yrs to > 30-yrs)

Although the limits in the table above are lower than the proposed limits, there are several other recently permitted NGCC units with limits that are equivalent to or greater than the proposed BACT limits.

7.6.6.2 CO_2 BACT Limit Selection

KU is proposing BACT for CO_2 for the combined cycle combustion turbine as efficient turbine operation and good combustion, operating, and maintenance practices to achieve a BACT emission limit of 815 lb/MW-g, demonstrated on a 12-month rolling basis with DB Firing and 925 lb/MW-g, demonstrated on a 12-month rolling basis without DB Firing. Compliance will be demonstrated through the use of CEMS and Part 75 procedures.

7.7 GT SU/SD BACT

The BACT limits for steady-state operation proposed in the preceding sections do not apply during the initial startup period for the NGCC and for add-on control devices, nor do they apply during NGCC shutdown periods. Separate BACT limits are necessary, given that add-on control devices are not operating at design conditions when the NGCC initially starts up and need time to reach operating conditions that allow for steady-state control performance. The amount of time it takes for each add-on control device to reach steady-state operating conditions is longer than the amount of time it takes the NGCC to reach its operating load. Accordingly, KU requests separate emission limits for pollutants affected by add-on controls (CO, VOC, and NO_X) during the time from the initial startup of the NGCC until add-on controls reach steady-state

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operating conditions. Startup and shutdown emissions for the NGCC for these three pollutants are presented in Section 4.6 of **Appendix B**.

For all pollutants, KU is proposing secondary BACT limits based on total annual emissions, in tons per year, inclusive of SU/SD periods. For pollutants other than CO, VOC, and NO_X, potential emissions from steady state operation are higher than from SU/SD, therefore the BACT limit proposed below is based on 8,760 hours of normal operation per year. For CO, VOC, and NO_X, the BACT limits proposed below include some amount of SU/SD operations. Refer to Section 3.1 for more information on how these annual emissions based BACT limits were derived. These proposed limits are included in Table 7-12 below.

Table 7-12. Proposed Annual BACT Limits Including SU/SD Events

Pollutant	BACT Limit (tpy)
NO_X	151.4
CO	134.6
VOC	64.6

Compliance will be demonstrated by calculating emissions on a 12-month rolling basis using the methodologies discussed in Section 3 of this application.

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8. BACT ANALYSIS FOR ANCILLARY EQUIPMENT

8.1 Auxiliary Boiler

As part of the NGCC EGU Project, KU is proposing to install the EU59 NG-Fired Auxiliary Boiler. The control technologies listed in the following subsections were obtained from the RBLC database for gas-fired boilers in the size range of the Auxiliary Boiler at Brown Station and from research of emerging technologies. KU queried RBLC for Process Codes 12.310 – Industrial Size Boilers/Furnaces >100 MMBtu/hr and 13.310 – Commercial/Institutional Size Boilers/Furnaces <100MMBtu/hr for the previous ten-year period. For the purpose of this analysis, only the entries for boilers firing NG were reviewed.

8.1.1 CO and VOC BACT for Auxiliary Boiler

The following sections present a review of pollutant formation and possible control technologies for CO and VOC emissions from the Auxiliary Boiler. Air pollution control strategies are evaluated using the top-down BACT approach. The underlying design includes the use of good combustion and operating practices to mitigate CO and VOC emissions from the Auxiliary Boiler while firing NG.

8.1.1.1 Background on Pollutant Formation

See Section 7.1.1 and Section 7.2.1 for a description on pollutant formation.

8.1.1.2 Step 1 – Identification of Potential Control Techniques

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable CO and VOC control technologies were identified based on the principles of the control technology and engineering experience for general combustion units. These technologies are listed as follows:

- Oxidation Catalyst
- Good Combustion Controls

Oxidation catalyst and good combustion controls were discussed in detail in Section 7.1.2 of this application.

8.1.1.3 Step 2 – Elimination of Technically Infeasible Control Options

After the identification of control options, the second step in the BACT analysis is to eliminate any technically infeasible control technologies. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest CE of the option would result in an emission level that is higher than any applicable regulatory limits. Since all options shown identified in Step 1 are technically feasible, no option will be eliminated in this step.

8.1.1.4 Step 3 – Rank Remaining Control Technologies

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 8-1.

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Table 8-1. Remaining CO and VOC Control Technologies

Rank	Control Technology	Potential Control Efficiency (%)
1	Oxidation Catalyst	50-90 for CO, 50-60 for VOC
2	Good Combustion Controls	Reduction Varies

8.1.1.5 Step 4 – Evaluation of Most Stringent Controls

After ranking the technically feasible control technologies, the fourth step of the analysis is to evaluate the control options on the basis of economic, energy, and environmental considerations, and document the results.

8.1.1.5.1 Oxidation Catalyst

The combined cycle power plant auxiliary boiler serves multiple steam users for plant startup and also supports HRSG freeze protection while the unit is off-line in cold weather conditions. The auxiliary steam load is subject to considerable variation and as such a turndown of 10:1 is required to support the range of operating loads. Recent project experience with several projects which elected to employ oxidation catalysts has resulted in operational issues due to the limited turndown capability of both technologies which have a turndown of 4:1. The turndown limitations have resulted in facilities installing steam vents and operating the auxiliary boiler well above its required duty to remain in compliance. The duty cycle for the auxiliary boiler requires operation below 25% MCR a significant portion of the time, and by limiting the annual hours of operation to 4,000 hours supports eliminating these types of modules.

8.1.1.5.2 Good Design and Operating Practices

The other remaining technology is good design and operating practices. A properly designed and operated boiler minimizes CO and VOC formation by ensuring that the boiler temperature and oxygen availability are adequate for complete combustion. Additionally, tune-ups will be performed as required under 40 CFR 63 Subpart DDDDD. Good design and operating practices are considered BACT for CO and VOC emissions for the proposed boiler.

8.1.1.6 Step 5 – Selection of CO and VOC BACT

8.1.1.6.1 Selection of CO BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Auxiliary Boiler will be subject to NSPS Subpart Dc and 401 KAR 59:015; however, neither includes an emission limit for CO or VOC. As such, there is no floor for an allowable CO or VOC BACT limit.

RBLC Review. Except for one RBLC entry, all similar sized NG-fired industrial boilers list good combustion practices as the control method. The Nemadji Trail Energy Center (WI-0300) specifies the use of oxidation catalysts is necessary to achieve a BACT emission limit of 0.0037 lb/MMBtu for VOC. This facility has not commenced construction or demonstrated compliance with the 0.0037 lb CO/MMBtu emission limit. KU is not confident that an emissions limit of 0.0037 lb CO/MMBtu is achievable in practice for an intermittent use boiler. The remaining emissions limits shown in the RBLC database are 0.035 lb CO/MMBtu and greater.

Selection of BACT. Based on the control technology evaluation, good design to achieve minimum emissions of CO is determined as the BACT for the Auxiliary Boiler. KU proposes a CO BACT emission limit of 0.037 lb/MMBtu on a 3-hour average basis and this is achievable with good combustion and operating

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practices. Compliance with the Auxiliary Boiler CO BACT limit will be based on an initial performance test conducted in accordance with U.S. EPA Method 10.

8.1.1.6.2 Selection of VOC BACT

Based on the control technology evaluation, good design and operation practices will be used to achieve minimum emissions of VOC is determined as the BACT for the Auxiliary Boiler. KU proposes a VOC BACT emission limit of 0.0054 lb/MMBtu on a 3-hour average basis.

RBLC database entries for VOC emissions from boilers range from 0.0015 lb/MMBtu to 0.008 lb/MMBtu, with 0.0054 lb/MMBtu being the most prevalent.

Therefore, KU is proposing an emission limit of 0.0054 lb/MMBtu consistent with the most recently approved PSD permits listed in the **Appendix D** search. {Given the reduced hours and the turndown issue…} Compliance with the Auxiliary Boiler VOC BACT limit will be based on an initial performance test conducted in accordance with U.S. EPA Methods 18, 25, or 25A.

8.1.2 NO_X BACT Evaluation for Auxiliary Boiler

8.1.2.1 Background on Pollutant Formation

See Section 7.3.1 for a description on pollutant formation.

8.1.2.2 Step 1 – Identification of Potential Control Techniques

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable NO_X control technologies were identified based on the principles of the control technology and engineering experience for general combustion units. These technologies are listed as follows:

- $EM_X/SCONO_X$
- SCR
- SNCR
- Ultra LNBs
- LNB with FGR (base case)

$EM_X/SCONO_X$, SCR and SNCR were discussed in detail in Section 7.3. FGR is discussed in detail in Section 7.3. Newer low-NO_X burners are designed to control fuel and air mixing in order to create larger and more branched flames. This lowers the flame temperature and results in a reduction in thermal NO_X formation. The improved flame structure also reduces the amount of oxygen available in the flame, improving burner efficiency. The low-NO_X levels are achieved by introducing fuel primarily to the pre-mix zones and reducing the amount of fuel being combusted from the pilot nozzle. FGR is a process that takes a portion of the fuel gas from the combustion process and recirculates it back into the boilers. For the purposes of this BACT analysis, FGR is considered in conjunction with LNBs.

8.1.2.3 Step 2 – Elimination of Technically Infeasible Control Options

After the identification of control options, the second step in the BACT analysis is to eliminate any technically infeasible control technologies. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest CE of the option would result in an emission level that is higher than any applicable regulatory limits.

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As specified in EPA's 1990 New Source Review Workshop Manual, "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; and the applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice". Since EM_X technology has not been demonstrated on NG-fired boilers, this technology is determined to be technically infeasible.

All other options identified in Step 1 are technically feasible.

8.1.2.4 Step 3 – Rank Remaining Control Technologies

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 8-2.

Table 8-2. Remaining NO_X Control Technologies

Rank	Control Technology	Potential Control Efficiency (%)[100]
1	SCR	50-90
2	Ultra LNB	70-76
3	SNCR	40-60
4	LNB with FGR	Reduction Varies

8.1.2.5 Step 4 – Evaluation of Most Stringent Controls

After ranking the technically feasible control technologies, the fourth step of the analysis is to evaluate the control options on the basis of economic, energy, and environmental considerations, and document the results.

8.1.2.5.1 SCR

KU evaluated the environmental, energy, and economic impacts of using SCR. No significant environmental impacts are expected from the operation of SCR. Energy impacts include the consumption of electricity to operate the system. Economic impacts for the installation of SCR are significant. The proposed boiler with base case LNBs has an emission rate of 30 ppmvd at 3 percent O_2. At the proposed capacity utilization and assuming that an SCR is capable of achieving 90 percent control for this installation, this equates to 6.2 tons of NO_X removed with the control device.

KU prepared a cost estimate using the U.S. EPA's Air Pollution Control Cost Estimation Spreadsheet for SCR (June 2019), which is based on Chapter 2 – Selective Catalytic Reduction Cost Manual that was last updated in June 2019.[101] Standard factors were used for a NG-fired boiler using the design specifications of the proposed Auxiliary Boiler. As shown in the complete cost analysis is provided in **Appendix E**, the estimated annualized total annual cost for an SCR would be $327,113 in 2024 dollars. Based on a cost analysis using these values, the cost of purchasing, installing, and operating SCR is approximately $53,060 per ton

[100] The control efficiencies identified in the table for SCR and SNCR represent typical control efficiency ranges for these control technologies and were used for ranking purposes only. The control efficiency for the ultra LNB was calculated based on a typical vendor guarantee of 9 ppmvd at 3% O_2 compared against an uncontrolled small boiler from AP-42, Table 1.4-1. The percent reductions from SCR and SNCR are general ranges expected from utility boilers which have higher inlet NO_X emissions.

[101] https://www.epa.gov/sites/default/files/2019-06/scrcostmanualspreadsheet_june-2019vf.xlsm

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controlled. This add-on control option would result in adverse economic impacts when compared to the underlying base case, which includes LNB with FGR as part of the design.

No NG-fired boilers listed in the RBLC with a heat input capacity less than 100 MMBtu/hr have installed SCR. Therefore, based on the environmental, energy, and economic analysis and a review of similar boilers in the RBLC database, SCR is not selected as BACT for control of NO_X emissions from the auxiliary boiler. Thus, KU proceeded with evaluating the next most efficient control option presented in Table 8-2.

8.1.2.5.2 Ultra LNBs

Ultra LNBs is the second highest ranking potentially feasible control technology for the Auxiliary Boiler. Compared with standard LNBs, the base case will achieve a control efficiency of approximately 77 percent. At the proposed capacity utilization and vendor guarantee, this equates to 5.7 tons of NO_X removed with the control technology.

As explained earlier, the auxiliary boiler serves multiple steam users for the NGCC plant startup and also supports HRSG freeze protection while the unit is off-line in cold weather conditions. The auxiliary steam load is subject to considerable variation and as such a turndown of 10:1 is required to support the range of operating loads. Recent project experience with several projects which elected to employ either ultra LNBs or SCR has resulted in operational issues due to the limited turndown capability of both technologies which have a turndown of 4:1. The turndown limitations have resulted in facilities installing steam vents and operating the auxiliary boiler well above its required duty to remain in compliance. The duty cycle for the auxiliary boiler requires operation below 25% MCR a significant portion of the time and a 10:1 turndown LNB with FGR is a technology that can support the application.

Based on the significant environmental, operational, and energy impact associated with this technology, Ultra LNBs are not selected as BACT for control of NO_X emissions from the Auxiliary Boiler. Thus, KU proceeded with evaluating the next most efficient control option presented in Table 8-2.

8.1.2.5.3 SNCR

KU evaluated the environmental, energy, and economic impacts of using SNCR. No significant environmental impacts are expected from the operation of SNCR. Energy impacts are attributed to only the electricity usage associated with operation of the SNCR itself, which are lower than that of SCR. Similar to SCR, economic impacts for the installation of SNCR are significant. At the proposed capacity utilization and assuming that an SNCR is capable of achieving 60 percent control for this installation, this equates to approximately 4.2 tons of NO_X removed with the control device.

KU prepared a cost estimate using the U.S. EPA's Air Pollution Control Cost Estimation Spreadsheet for SCR (June 2019), which is based on Chapter 1 – Selective Noncatalytic Reduction Cost Manual that was last updated in April 2019.[102] Standard factors were used for a NG-fired boiler using the design specifications of the proposed Auxiliary Boiler. As shown in the complete cost analysis is provided in **Appendix E**, the estimated annualized total annual cost for an SNCR would be $171,192 in 2024 dollars. Based on a cost analysis using these values, the cost of purchasing, installing, and operating SNCR is approximately $41,195 per ton controlled. This add-on control option would result in adverse economic impacts when compared to the underlying base case, which includes LNBs with FGR as part of the design.

[102] https://www.epa.gov/sites/default/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm

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KU has determined that SNCR is not BACT based on the environmental, energy, and economic analysis. This determination is consistent with the RBLC database, as no facilities in the database have installed SNCR for control of NO_X emissions from an NG-fired boiler less than 100 MMBtu/hr.

8.1.2.5.4 LNBs with FGR

The proposed Auxiliary Boiler is equipped with LNBs and FGR. Based on the insignificant environmental and energy impact associated with this technology and the feasibility from an economic standpoint, KU has determined that LNBs with FGR are the BACT for the Auxiliary Boiler.

8.1.2.6 Step 5 – Selection of NOx BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Auxiliary Boiler will be subject to NSPS Subpart Dc and 401 KAR 59:015; however, neither includes an emission limit for NOx. As such, there is no floor for an allowable NOx BACT limit.

RBLC Review. Emission limits in the RBLC database range from 0.006 lb/MMBtu to 0.1 lb/MMBtu, with several recent BACT determinations approved at values of 0.011 lb/MMBtu and greater, including several units with similar heat input capacity at 0.035 to 0.04 lb/MMBtu in 2022 and 2023. The proposed emission limit is consistent with the emission limits provided in the RBLC database.

Selection of BACT. Based on the control technology evaluation, low NO_X burners with FGR were determined as the BACT for the Auxiliary Boiler. KU proposes a BACT emission limit of 0.0364 lb/MMBtu on a 3-hour average basis via stack testing. Compliance with the proposed NO_X BACT limit will be demonstrated based on an initial performance test, if requested.

8.1.3 $PM/PM_{10}/PM_{2.5}$ BACT for Auxiliary Boiler

8.1.3.1 Background on Pollutant Formation

See Section 7.4.1 for a description on pollutant formation.

8.1.3.2 Step 1 – Identification of Potential Control Techniques

Using the RBLC search and permit review results, potentially applicable $PM/PM_{10}/PM_{2.5}$ control technologies for a gas-fired boiler were identified. The only available control option is combustion design controls.

8.1.3.3 Step 2 – Elimination of Technically Infeasible Control Options

Combustion design controls are a technically feasible control option for reducing PM emissions from the Auxiliary Boiler.

8.1.3.4 Step 3 – Rank Remaining Control Technologies

Implementing combustion design controls provides the most effective means for reducing emissions of $PM/PM_{10}/PM_{2.5}$ from the Auxiliary Boiler.

8.1.3.5 Step 4 – Evaluation of Most Stringent Controls

The top and only available and technically feasible PM control option will be applied to achieve compliance with the proposed BACT limit.

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8.1.3.6 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Auxiliary Boiler will be subject to NSPS Subpart Dc and 401 KAR 59:015; which includes an emission limit of 0.1 lb PM/MMBtu as discussed in Section 5.7.4.

RBLC Review. Emission limits in the RBLC database range from 0.0007 lb/MMBtu to 0.01 lb/MMBtu, with several recent BACT determinations approved at values of 0.0035 lb/MMBtu and greater, including several units with similar heat input capacity at 0.0075 to 0.008 lb/MMBtu in 2022 and 2023. Based on review of the RBLC database, KU believes that the proposed PM, PM_{10}, and $PM_{2.5}$ BACT limit is consistent with established limits for comparable boilers.

Selection of BACT. KU proposes a PM, PM_{10}, and $PM_{2.5}$ BACT emission limit of 0.0070 lb/MMBtu (filterable plus condensable) on a 3-hour average basis. Compliance with the Auxiliary Boiler PM BACT limit will be based on an initial performance test conducted in accordance with approved U.S. EPA reference test methods for measuring filterable and CPM emissions.

8.1.4 H_2SO_4 BACT for Auxiliary Boiler

8.1.4.1 Background on Pollutant Formation

See Section 7.5.1 for a description on pollutant formation.

8.1.4.2 Step 1 – Identification of Potential Control Techniques

Emissions of H_2SO_4 depend upon the sulfur content of the fuel and oxidation of SO_2 to SO_3, followed by immediate conversion of SO_3 to H_2SO_4 when water vapor is present. H_2SO_4 emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

- FGD System;
- DSI; and
- Fuel Specification.

Neither FGD systems nor dry sorbent injection systems are listed in the RBLC as BACT for the control of H_2SO_4 emissions for auxiliary boilers. These technologies have not been applied to NG auxiliary boilers due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction. As such, the use of FGD systems and dry sorbent injection systems are not discussed further.

8.1.4.3 Step 2 – Elimination of Technically Infeasible Control Options

Based on the information reviewed for this BACT determination, KU has determined that the use of dry sorbent injection is not a technically feasible option for the Auxiliary Boiler at this source.

8.1.4.3.1 Fuel Specifications

Combusting only clean NG, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with NG has a very low potential for generating H_2SO_4 emissions. Fuel specifications are included in RBLC for the control of H_2SO_4 emissions from auxiliary boilers.
Based on the information reviewed for this BACT determination, KU has determined that the use of fuel specifications is a technically feasible option for the Auxiliary Boiler at this source.

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8.1.4.4 Step 3 – Rank Remaining Control Technologies

The only remaining control measure identified for control of H_2SO_4 resulting from the operation of the Auxiliary Boiler is fuel specifications.

8.1.4.5 Step 4 – Evaluation of Most Stringent Controls

The top and only available and technically feasible H_2SO_4 control option will be applied to achieve compliance with the proposed BACT limit.

8.1.4.6 Step 5 – Selection of BACT for Auxiliary Boiler

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Auxiliary Boiler has no floor for an allowable H_2SO_4 BACT limit.

RBLC Review. The RBLC database includes low-sulfur fuel and pipeline quality natural gas as the control method for similar NG-fired units.

Selection of BACT. KU proposes combustion of pipeline-quality NG as BACT for H_2SO_4. Compliance with the Auxiliary Boiler H_2SO_4 BACT limit will be based on confirmation from the NG supplier that sulfur content is within the specification of the definition of pipeline quality NG. {0.5 gr/100 scf.}

8.1.5 GHGs BACT for Auxiliary Boiler

8.1.5.1 Background on Pollutant Formation

See Section 7.6.1 for a description on pollutant formation.

8.1.5.2 Step 1 – Identification of Potential Control Techniques

CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. There are no known supplemental controls for N_2O or methane emissions from gas-fired units. Therefore, this BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

- Alternative Fuels-Biomass/Co-firing
- Low Carbon Fuel Source; and
- Good Combustion Practices

8.1.5.3 Step 2 – Elimination of Technically Infeasible Control Options

8.1.5.3.1 Alternative Fuels-Biomass/Co-firing

The potential on-site reduction in CO_2 emissions that may be realized by switching from a traditional fossil fuel to a biomass fuel is based on the specific emission factor for the fuel as related to its caloric value. Pure biomass fuels include animal meal, waste wood products and sawdust, and sewage sludge. It may also be possible to use biomass materials that are specifically cultivated for fuel use, such as wood, grasses, green algae, and other quick growing species. Gas co-firing involves modification of the combustion system to accommodate the introduction of NG or biomass-derived gas. The co-fired fuel is injected directly into the combustion zone. While co-firing of NG or biofuels does not present any technical issues which cannot be addressed through appropriate design, availability of gaseous biomass-based fuels is limited such that a consistent supply of such fuels cannot be assured over the life of the boilers. In addition, the combustion of

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biomass-based fuels can affect compliance with BACT limits for other pollutants, such as NO_X and CO. Therefore, the boiler will be constructed and operated to utilize only NG.

Based on the information reviewed for this BACT determination, KU has determined that the use of alternative fuels-biomass/co-firing is not a technically feasible option for the Auxiliary Boiler at this source.

8.1.5.3.2 Low Carbon Fuel Use

Based on the information reviewed for this BACT determination, KU has determined that the use of a fuel other than NG would change the design and purpose of the boiler's use within this NGCC EGU Project. Moreover, the Auxiliary Boiler will be firing NG that has less CO_2 emissions per Btu than liquid or solid fuels.

8.1.5.3.3 Good Combustion Practices

Boiler efficiency decreases over time; however, the rate of deterioration can be curbed by proper O&M and combustion practices. A well operated and maintained plant will experience less deterioration of boiler efficiency. Deterioration results in higher heat rate, CO_2 emissions, and operating costs; in lower reliability; and in some cases, reduced output. After a few years of neglect, it may reach the point where significant investment is required to rehabilitate the plant and bring it as close as possible to the design performance. Rehabilitation may focus on life extension and reliability improvement of the plant or may include additional measures that improve plant efficiency, occasionally above the original design efficiency. The efficiency can be improved by retrofitting combustion control technologies such as heat recovery systems, control devices, and upgraded burners. Additional GHG reductions can be achieved through energy improvements in the steam/hot water distribution system, the boiler auxiliaries, or in process efficiency improvements.

Operation and maintenance according to the manufacturer's emission-related instructions or per a facility-developed maintenance plan (in a manner consistent with safety and good air pollution control practices for minimizing emissions) will prevent generation of additional GHG emissions due to efficiency losses over the lifetime of each piece of combustion equipment. These practices may include, but are not limited to: Efficient burner design, combustion tuning, optimization and use of a digital control system, boiler insulation, minimization of air filtration, boiler blowdown heat exchange, condensation return system, minimization of gas-side heat transfer surface deposits, and steam line maintenance.

Based on the information reviewed for this BACT determination, KU has determined that the use of good combustion practices is a technically feasible option for the Auxiliary Boiler at this source.

8.1.5.4 Step 3 - Rank Remaining Control Technologies

Table 8-3 ranks the control technologies in descending order of maximum CE.

Table 8-3. Ranked GHG Control Options

Rank	Control Option	Control Efficiency (%)
1	Good Combustion Practices	Reduction Varies

8.1.5.5 Step 4 – Evaluation of Most Stringent Controls

KU has chosen to apply good combustion practices for selecting a BACT emission limit.

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8.1.5.6 Step 5 – Selection of GHG BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Auxiliary Boiler has no floor for an allowable GHG BACT limit.

RBLC Review. The RBLC database lists low carbon fuels and good combustion practices as the control method for similar NG-fired units.

Selection of BACT. KU proposes a CO_2e BACT emission limit of 117.1 lb of GHGs/MMBtu with compliance demonstrated by combusting pipeline quality NG and maintaining and operating the Auxiliary Boiler in accordance with manufacturer's recommendations.

8.2 Dewpoint Preheater

8.2.1 CO and VOC BACT for Dewpoint Preheater

8.2.1.1 Background on Pollutant Formation

See Section 7.1.1 and Section 7.2.1 for a description on pollutant formation.

8.2.1.2 Step 1 – Identification of Potential Control Techniques

The following control options have been identified:

- Oxidation catalyst
- Good combustion practices

Oxidation catalyst and good combustion practices were discussed in Section 7.1.2 of this application.

8.2.1.3 Step 2 – Elimination of Technically Infeasible Control Options

The next step in the process is to evaluate all possible options and determine if any options are technically infeasible for the proposed project.

8.2.1.3.1 Oxidation Catalyst

The results from the RBLC database search do not include oxidation catalyst for CO BACT compliance. KU is not aware of any heaters that have demonstrated the use of such a system and therefore does not consider this technology to meet the "applicable" requirement. For this reason, oxidation catalyst is not technically feasible.

8.2.1.3.2 Good Combustion Practices

Good combustion practices, such as controlling the air/oxygen supply and maintaining an appropriate temperature in the combustion chambers, is included in the baseline design of the proposed project. Therefore, this control method is considered to be technically feasible.

8.2.1.4 Step 3 – Rank Remaining Control Technologies

Table 8-4 ranks the control technologies in descending order of maximum CE.

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Table 8-4. Ranked CO/VOC Control Options

Rank	Control Option	Control Efficiency (%)
1	Good Combustion Practices	Reduction Varies

8.2.1.5 Step 4 – Evaluation of Most Stringent Controls

KU has chosen to apply good combustion practices for selecting a BACT emission limit.

8.2.1.6 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The heater will be subject to NSPS Subpart Dc and 401 KAR 59:015; however, neither includes an emission limit for CO or VOC. As such, there is no floor for an allowable CO or VOC BACT limit.

RBLC Review. The proposed limits are consistent with the most prevalent emission limits included in the RBLC database, including emission limits from the 2022 and 2023 calendar years.

Selection of BACT. KU will reduce CO and VOC emissions through the use of good combustion controls, according to the requirements of BACT. For the fuel gas preheater, KU is proposing a CO BACT limit of 0.038 lb/MMBtu on a three-hour block average basis and a VOC BACT limit of 0.008 lb/MMBtu on a three-hour block average basis. Compliance will be demonstrated through the combustion of pipeline quality NG, maintaining and operating combustion sources in accordance with manufacturer's recommendations. Given the size and intermittent operation of these units, it is KU's position that no source testing is needed.

8.2.2 NO_X BACT for Dewpoint Heater

8.2.2.1 Background on Pollutant Formation

See Section 7.3.1 for a description on pollutant formation.

8.2.2.2 Step 1 – Identification of Potential Control Techniques

The following control options have been identified by KU as possible techniques to reduce NO_X emissions:

- SCR
- SNCR
- LNBs
- Good combustion practices

These control technologies were previously described in Sections 7.3.

FGR is generally limited for applications in larger, indirect-fired boilers and process heaters/furnaces where the burner flame zone is accessible for the re-introduction of flue gas. This technology will not be discussed further as it is not available to the fuel gas preheater. As previously stated, the ideal flue gas temperature range for optimal SCR and SNCR operation is 700°F to 750°F. However, the exhaust temperature for the heater is approximately 500°F. Since the temperature is not within the required operating range and has not been demonstrated for similar units, neither SCR nor SNCR will not be discussed further.

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8.2.2.3 Step 2 – Elimination of Technically Infeasible Control Options

8.2.2.3.1 Low NO_X Burners

LNBs are considered technically feasible.

8.2.2.3.2 Good Combustion Practices

Good combustion practices are included in KU's baseline design and therefore technically feasible.

8.2.2.4 Step 3 – Rank Remaining Control Technologies

Table 8-5 ranks the NO_X control technologies in descending order of maximum CE.

Table 8-5. Ranked NO_X Control Options – Boilers and Oil Heaters

Rank	Control Option	Control Efficiency (%)
1	Low NO_X burners	38%-63% Reduction
2	Good combustion practices	Varies

8.2.2.5 Step 4 – Evaluation of Most Stringent Controls

8.2.2.5.1 Low NO_X Burners

LNBs are proposed for the fuel gas preheater based on availability for sources in the proposed size range.

8.2.2.5.2 Good Combustion Practices

Good combustion practices are included in KU's baseline design for the dewpoint heater and do not pose any adverse energy, environmental, or economic impacts.

8.2.2.6 Step 5 – Selection of NOx BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The heater will be subject to NSPS Subpart Dc and 401 KAR 59:015; however, neither includes an emission limit for NO_X. As such, there is no floor for an allowable NO_X BACT limit.

RBLC Review. The RBLC database contains entries with lower emission limits for similar small, NG-fired combustion units, these units are not required to demonstrate compliance through source testing, and in most cases are not designed to allow for direct measurement of emissions. Therefore, little data is available to prove that the units comply with these limits. Given the relatively low emissions from small, NG-fired combustion units, and the uncertainty with respect to the performance of these units, KU's proposed emission limits represent BACT-level control.

Selection of BACT. KU will reduce NO_X emissions from the preheater through the use of LNBs, according to the requirements of BACT. KU proposes a BACT limit of 0.038 lb/MMBtu on a three-hour block average basis. Compliance will be demonstrated through the combustion of pipeline quality NG and maintaining and operating combustion sources in accordance with manufacturer's recommendations.

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8.2.3 $PM/PM_{10}/PM_{2.5}$ BACT for Dewpoint Heater

8.2.3.1 Background on Pollutant Formation

See Section 7.4.1 for a description on pollutant formation.

8.2.3.2 Step 1 – Identification of Potential Control Techniques

Using the RBLC search and permit review results, potentially applicable $PM/PM_{10}/PM_{2.5}$ control technologies for NG-fired heaters were identified. The only available control option is combustion design controls.

8.2.3.3 Step 2 – Elimination of Technically Infeasible Control Options

Combustion design controls are technically feasible control options for reducing PM emissions from the heater.

8.2.3.4 Step 3 – Rank Remaining Control Technologies

Implementing combustion design controls provides the most effective means for reducing emissions of $PM/PM_{10}/PM_{2.5}$ from the heater.

8.2.3.5 Step 4 – Evaluation of Most Stringent Controls

The top and only available and technically feasible PM control option will be applied to achieve compliance with the proposed BACT limit.

8.2.3.6 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The heater will be subject to NSPS Subpart Dc and 401 KAR 59:015; which includes an emission limit of 0.1 lb PM/MMBtu as discussed in Section 5.7.4.

RBLC Review. Based on review of the RBLC database, KU believes that the proposed PM, PM_{10}, and $PM_{2.5}$ BACT limit is consistent with established limits for comparable NG heaters.

Selection of BACT. KU proposes a PM, PM_{10}, and $PM_{2.5}$ BACT emission limit of 0.0034 lb/MMBtu on a 3-hour average basis. Given the size and intermittent operation of this unit, it is KU's position that no source testing is needed.

8.2.4 H_2SO_4 BACT

8.2.4.1 Background on Pollutant Formation

See Section 7.5.1 for a description on pollutant formation.

8.2.4.2 BACT Step 1 – Identification of Potential Control Techniques

H_2SO_4 emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. Add-on control equipment for reduction of H_2SO_4 emissions from small, NG-fired combustion sources has not been demonstrated, and is therefore not an available control. The only available control option for reduction of H_2SO_4 emissions is the use of fuel specifications, or combustion of low sulfur fuels.

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8.2.4.3 Step 2 – Elimination of Technically Infeasible Control Options

Combusting only clean NG, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with NG has a very low potential for generating H_2SO_4 emissions. Fuel Specifications are included in RBLC for the control of H_2SO_4 emissions from heaters.

Based on the information reviewed for this BACT determination, KU has determined that the use of Fuel specifications is a technically feasible option for the heater included in the project.

8.2.4.4 Step 3 – Rank of Remaining Control Technologies

The only measure identified for control of H_2SO_4 resulting from the operation of the heater is the use of fuel specifications.

8.2.4.5 Step 4 – Evaluation of Most Stringent Controls

The top and only available and technically feasible H_2SO_4 control option will be applied to achieve compliance with the proposed BACT limit.

8.2.4.6 Step 5 – Selection of BACT

KU proposes combustion of pipeline-quality NG as BACT for H_2SO_4. Compliance with the H_2SO_4 BACT limit will be based on confirmation from the NG supplier that sulfur content is within the specification of the definition of pipeline quality NG.

8.2.5 GHGs BACT for Dewpoint Heater

8.2.5.1 Background on Pollutant Formation

See Section 7.6.1 for a description on pollutant formation.

8.2.5.2 Step 1 – Identification of Potential Control Techniques

CO_2 is by far the dominant GHG from this source. CH_4 and N_2O are present only in very small amounts, are incidental to combustion, and trend with the CO_2 emissions. This BACT analysis focused on CO_2 as a surrogate for all GHG emissions.

- O&M Practices;
- Efficient Burner Design; and
- Good Combustion Practices

8.2.5.3 Step 2 – Elimination of Technically Infeasible Control Options

All of the control techniques identified for small, NG-fired heaters are technically feasible.

8.2.5.4 Step 3 - Rank Remaining Control Technologies

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 8-6.

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Table 8-6. Remaining GHG Control Technologies

Rank	Control Technology	Potential Control Efficiency (%)
1	Efficient Burner Design	Reduction Varies
2	O&M Practices	Reduction Varies
3	Good Combustion Practices	Reduction Varies

8.2.5.5 Step 4 – Evaluation of Most Stringent Controls

KU has chosen to apply Efficient Burner Design, O&M Practices, and Good Combustion Practices for selecting a BACT limit. Therefore, no further evaluation under Step 4 is required.

8.2.5.6 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Dewpoint Heater has no floor for an allowable GHG BACT limit.

RBLC Review. The RBLC database lists low carbon fuels and good combustion practices as the control method for similar units.

Selection of BACT. KU proposes a CO_2e BACT emission limit for the preheater of 117.1 lb/MMBtu with compliance demonstrated by combusting pipeline NG. CO_2e emissions from the heater shall be controlled through the use of good combustion practices.

8.3 Internal Combustion Engines

Two diesel fired emergency engines are included in the proposed project; one emergency fire suppression system and one emergency generator. The fire pump engine will be an NFPA certified nominal 422 hp compression ignition fire pump engine and will be run on ULSFO, with a maximum sulfur content of 0.0015 weight percent (15 ppmw). The generator engine will be nominal 2.18 MW (2,923 bhp) compression ignition engine and will be run on ULSFO, with a maximum sulfur content of 0.0015 weight percent (15 ppmw). Combustion of the ULSFO will yield emissions of CO, VOC, NO_X, PM, PM_{10}, $PM_{2.5}$, and GHGs.

8.3.1 CO and VOC BACT for Engines

8.3.1.1 Background on Pollutant Formation

See Section 7.1.1 and Section 7.2.1 for a description on pollutant formation.

8.3.1.2 Step 1 – Identification of Potential Control Techniques

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable CO and VOC control technologies were identified based on the principles of the control technology and engineering experience for CI ICE. These technologies are listed as follows:

- Catalytic/Thermal Oxidation
- Combustion Design Controls

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8.3.1.3 Step 2 – Elimination of Technically Infeasible Control Options

Although thermal or catalytic oxidation are technically feasible, these technologies may not provide consistent CO and VOC control efficiencies and may be difficult to operate when used to reduce CO and VOC emissions from sources that operate for short periods of time and that experience frequent starts/stops. Since it can take time for the exhaust stream to reach the required operating temperature range for efficient oxidation, the CO and VOC CE of thermal or catalytic oxidation for an engine is lower than for a unit that runs at steady-state. Except for emergencies, the engines will normally only run for less than one hour a week for readiness testing.

Combustion design controls are a technically feasible control option for reducing CO and VOC emissions from ICEs.

8.3.1.4 Step 3 – Rank Remaining Control Technologies

The remaining control technologies are presented in Table 8-7 in order of control effectiveness.

Table 8-7. Remaining CO and VOC Control Technologies – Emergency Engines

Rank	Control Technology	Potential Control Efficiency (%)
1	Catalytic/Thermal Oxidation	50-90 for CO, 50-60 for VOC
2	Combustion Design Controls	Reduction Varies

Implementing combustion design controls provides the most effective means for achieving CO and VOC emissions reductions.

8.3.1.5 Step 4 – Evaluation of Most Stringent Controls

EPA determined in the development of NSPS Subpart IIII that add-on controls are economically infeasible for emergency ICE. As such, the implementation of thermal or catalytic oxidation is economically infeasible.

KU has determined that the top and only remaining available and technically feasible CO and VOC control option, combustion design controls, will be applied to achieve compliance with the proposed BACT limit.

8.3.1.6 Step 5 – Selection of BACT

8.3.1.6.1 Select CO BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for CO. As such, NSPS IIII sets the floor for an allowable CO BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, KU believes that the proposed CO BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

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Selection of BACT. KU proposes a CO BACT emission limit for the fire pump equal to that of the applicable NSPS IIII Tier 3 standard, or 2.6 g/bhp-hr.[103]

KU proposes a CO BACT emission limit for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 2.6 g /bhp-hr.[104]

To comply with the proposed CO BACT limits, KU will purchase engines certified by the manufacturers to meet these emission levels. Operation of the ICE for the purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance) will be limited to 100 hours per year (each engine). The total annual hours of operation for the ICE including periods of operation at full loads for emergency use are expected to be less than 500 hours (each engine).

8.3.1.6.2 Select VOC BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for VOC in the form of a combined NO_X + NMHC emission limit. As such, NSPS IIII sets the floor for an allowable VOC BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, KU believes that the proposed VOC BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

Selection of BACT. KU proposes a combined BACT emission limit for NO_X and NMHC for the fire pump equal to that of the applicable NSPS IIII standard, or 3.0 g/hp-hr.

KU proposes a combined BACT emission limit for NO_X and NMHC for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 4.8 g/hp-hr.

To comply with the proposed BACT limits, KU will purchase engines certified by the manufacturers to meet these emission levels. Operation of the ICE for the purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance) will be limited to 100 hours per year (per engine). The total annual hours of operation for the ICE including periods of operation at full loads for emergency use are expected to be less than 500 hours (per engine). Based on review of the RBLC database, KU believes that the proposed CO and VOC BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

8.3.2 NO_X BACT for Engines

The following sections present a review of pollutant formation and possible control technologies for NO_X emissions from the CI ICE. Air pollution control strategies are evaluated using the top-down BACT approach.

[103] Pursuant to §60.4205(c), the fire pump engines (which have a displacement less than 30 liters per cylinder) are subject to the emission limits from Table 4 of Subpart IIII.

[104] Pursuant to §60.4205(b), the emergency engines (which have a displacement less than 30 liters per cylinder) are subject to the corresponding Tier emission limits from Appendix I to Part 1039.

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8.3.2.1 Background on Pollutant Formation

See Section 7.3.1 for a description on pollutant formation.

8.3.2.2 Step 1 – Identification of Potential Control Techniques

Using the RBLC search and permit review results, as well as review of technical literature, potentially applicable NO_X control technologies were identified based on the principles of the control technology and engineering experience for internal combustion engines. These technologies are listed as follows:

- SCR
- SNCR
- Combustion Design Controls

SCR and SNCR were discussed in detail in previous sections of the application. Applying SNCR and SCR to the diesel engines at the facility may be challenging from an operations standpoint due to the varying conditions of the exhaust. The NO_X emission rate from the engines will vary during startup and depend upon the operating conditions of the engine. Under these conditions, an SCR or SNCR unit would not be capable of achieving steady-state operation and would pose adverse environmental impacts due to ammonia slip or urea release. SCR and SNCR will not be discussed further in this section.

8.3.2.3 Step 2 – Elimination of Technically Infeasible Control Options

Combustion design controls are a technically feasible option for reducing NO_X emissions from CI ICE.

8.3.2.4 Step 3 – Rank Remaining Control Technologies

Combustion design controls are a technically feasible option for reducing NO_X emissions from CI ICE.

8.3.2.5 Step 4 – Evaluation of Most Stringent Controls

With all add-on NO_X control options eliminated, combustion design controls, the top and only remaining available and technically feasible NO_X control option, will be applied to achieve compliance with the proposed BACT limits.

8.3.2.6 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for NO_X in the form of a combined limit for NO_X + NMHC. As such, NSPS IIII sets the floor for an allowable NO_X BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, KU believes that the proposed NO_X BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

Selection of BACT. As stated in Section 8.3.1.6.2, KU proposes a combined BACT emission limit for NO_X and NMHC for the fire pump equal to that of the applicable NSPS IIII Tier 3 standard, or 3.0 g/hp-hr.

KU proposes a combined BACT emission limit for NO_X and NMHC for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 4.8 g/hp-hr.

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To comply with the proposed BACT limits, KU will purchase emergency engines certified by the manufacturers to meet these emissions levels. Operation of the engines for the purposes of maintenance checks and readiness testing will be limited to 100 hours per year per engine) and the total annual hours of operation including emergency use will be limited to 500 hours per year (per engine). Based on review of the RBLC database, KU believes that the proposed NO_X and NMHC BACT limits are consistent with the most stringent limits in the RBLC for comparable diesel emergency engines.

8.3.3 Filterable $PM/PM_{10}/PM_{2.5}$ BACT for Engines

8.3.3.1 Background on Pollutant Formation

See Section 7.4.1 for a description on pollutant formation.

8.3.3.2 Step 1 – Identification of Potential Control Techniques

Potentially available control options for reducing filterable PM emissions from emergency engines are listed below:

- Catalyzed Diesel Particulate Filter (CDPF)
- Combustion Design Controls
- Usage Limitations
- Usage of Clean Fuels

8.3.3.3 Step 2 – Elimination of Technically Infeasible Control Options

All controls options are technically feasible control options for reducing filterable PM emissions from diesel engines. Therefore, no control options are eliminated in this step of the analysis.

8.3.3.4 Step 3 – Rank Remaining Control Technologies

Particulate filters provide the most effective means for reducing filterable PM emissions from ICEs with a CE of up to 94 percent depending on the size of the engine.[105] Implementing combustion design controls, usage limitations and usage of clean fuels are the next most effective control option for reducing PM emissions.

8.3.3.5 Step 4 – Evaluation of Most Stringent Controls

As previously stated in Section 8.3.1.5, EPA determined in the development of NSPS Subpart IIII that add-on controls are economically infeasible for emergency ICE. Based on EPA's economic analysis, KU has determined that CDPF is not BACT for filterable PM emissions from the diesel engines.

With CDPF eliminated, combustion design controls usage limitations and usage of clean fuels are the remaining available and technically feasible filterable PM control options will be applied to achieve compliance with the proposed BACT limit.

[105] Memo from Ms, Tanya Parise, Alpha Gamma Technologies, Inc. to Mr. Sims Roy, U.S. EPA OAQPS ESD Combustion Group. *Cost per Ton for NSPS for Stationary CI ICE*. June 9, 2005.

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8.3.3.6 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The fire pump engine and emergency generator engine will both be subject to NSPS IIII, which includes an emission limit for PM. As such, NSPS IIII sets the floor for an allowable PM BACT limit.

RBLC Review. Similarly sized internal combustion engines list compliance with NSPS IIII in conjunction with good combustion practices as the control method. As such, KU believes that the proposed PM BACT limits are consistent with the most stringent limits shown in the RBLC for comparable diesel emergency engines.

Selection of BACT. KU proposes a filterable PM BACT emission limit for the fire pump equal to that of the applicable NSPS IIII Tier 3 standard, or 0.15 g/bhp-hr. KU proposes a filterable PM BACT emission limit for the emergency generator equal to that of the applicable NSPS IIII Tier 2 standard, or 0.15 g/bhp-hr.

To comply with the proposed BACT limits, KU will purchase engines certified by the manufacturers to meet these emissions levels. Operation of the engines for the purposes of maintenance checks and readiness testing will be limited to 100 hours per year (per engine) and the total annual hours of operation including emergency use will be limited to 500 hours per year (per engine). Based on review of the RBLC database, KU believes that the proposed filterable PM BACT limit is consistent with established filterable PM BACT limits for comparable diesel emergency engines.

8.3.4 GHG BACT

8.3.4.1 Background on Pollutant Formation

See Section 7.6.1 for a description on pollutant formation.

8.3.4.2 Step 1 – Identification of Potential Control Techniques

Available GHG control technologies are presented in the following sections for diesel-driven engines. There are no NSPS or NESHAPs that can be used to establish a floor for GHG emission rates from these combustion sources. Likewise, no similar facilities or facilities with similar process types were identified in the RBLC as using any type of add-on control device. This finding is important and bolsters the conclusion that BACT should be represented by emission limits that do not account for the implementation of an add-on control device.

Based on a review of technical literature, past control technology determinations, and generally available technologies and practices, the following options could potentially be applied to control GHG emissions from KU's diesel combustion equipment:

- Fuel Selection
- Good Design and Operating Practices

8.3.4.2.1 Fuel Selection

The carbon intensity of fuels can vary significantly across available fossil fuels commonly used in industry. Fuels with low carbon intensity have lower GHG emissions than fuels with high carbon intensity. Therefore, GHG BACT considerations involve the evaluation of low carbon intensity fuel options. By selecting a low carbon fuel, GHG emissions are minimized. Diesel is the standard fuel type

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for this equipment, given its ease of handling and storage, its suitability for use in emergency equipment with highly variable operations, and its prevalence of use in engine technology.

8.3.4.2.2 Good Design and Operating Practices

Good design and operating practices for controlling GHG emissions from diesel-fired engines consist of minimizing startup and idling time, in addition to good air to fuel mixing to promote complete combustion. By operating a combustion unit as efficiently as possible, GHG emissions are minimized. This is achieved in normal practice for emergency-use engines that, by design, only operate for maintenance purposes, readiness testing, and during emergency events.

8.3.4.3 Step 2 – Elimination of Technically Infeasible Control Options

8.3.4.3.1 Good Design and Operating Practices

KU will implement good combustion design and operating practices on each diesel-fired emergency engine. The various unit vendors have implemented design elements that promote complete combustion and efficiency. As such, these good operating practices include the optimization of energy efficiency.

8.3.4.4 Step 3 – Rank Remaining Control Technologies

Good design and operating practices are normal practice for emergency-use engines, so no additional GHG reduction can be attributed.

8.3.4.5 Step 4 – Evaluation of Most Stringent Controls

For emergency equipment, GHG BACT considerations will include optimum engine efficiency and good design and operating practices. There are no significant economic, environmental, or energy impacts associated with the selected control methods.

8.3.4.6 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The engines have no floor for an allowable GHG BACT limit.

RBLC Review. The RBLC database lists good combustion practices as the control method for similar units.

Selection of BACT. KU proposes to operate the emergency engines in accordance with good combustion and operating practices to achieve compliance with the following GHG BACT limit:

- 163.6 lb/MMBtu CO_2e for the emergency generator and emergency fire pump engines

With no add-on controls available, the only effective methods of reducing GHG emissions are the selection of energy efficient engines and the implementation of good combustion, operating, and maintenance practices to minimize GHG emissions.

8.4 PM BACT for Cooling Tower

The proposed cooling tower is a multi-cell, mechanically induced draft cooling tower used in the condensate system and other plant systems, designed to remove heat from cooling water. PM emissions originate from

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the dissolved metals (e.g., calcium, magnesium, etc.) in the water circulated in the cooling tower that crystallize and form airborne particles as the water drift leaves the cooling tower. Drift eliminator technology has been developed to reduce the potential for cooling tower drift.

8.4.1 Step 1 – Identification of Potential Control Techniques

Potentially available control options for reducing PM emissions from mechanical draft wet cooling towers include options to minimize dissolved solids in the cooling water and add-on controls such as advanced drift eliminators. All modern wet cooling towers are equipped with drift (mist) eliminators. This control option is designated as BACT for each cooling tower in the RBLC as shown in **Appendix D.**

As discussed in the cooling tower research paper used as the basis for the PM_{10} and $PM_{2.5}$ particle size multipliers referenced in **Appendix B**, the fraction of PM emitted as PM_{10} and $PM_{2.5}$ is primarily a function of the drift droplet size distribution.[106] The drift droplet size distribution from a mechanical draft cooling tower can vary based on fill design, the air and water flow patterns within the tower, frequency of tower maintenance, and operating levels.[107] Based on this complex interaction between cooling tower design and operating characteristics and the fact that U.S. EPA has not promulgated an approved test method for measuring PM emissions in cooling tower drift, no cooling tower control options specifically targeting PM_{10} or $PM_{2.5}$ removal were identified. Drift eliminators do, however, reduce drift formation which in turn reduces all size fractions of PM emissions.

8.4.2 Step 2 – Elimination of Technically Infeasible Control Options

All control options identified are technically feasible.

8.4.3 Step 3 – Rank Remaining Control Technologies

Utilizing drift (mist) eliminators and minimizing dissolved solids in the circulating water are the only technically feasible control options for reducing $PM/PM_{10}/PM_{2.5}$ emissions from the cooling towers. Modern wet cooling towers with advanced drift eliminators generally achieve a drift rate around 0.001 percent.

8.4.4 Step 4 – Evaluation of Most Stringent Controls

The top and only available and technically feasible $PM/PM_{10}/PM_{2.5}$ control options will be applied to achieve compliance with the proposed BACT limit. The environmental, energy, and economic impacts of drift eliminators and minimizing dissolved solids are insignificant.

8.4.5 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The Cooling Tower has no floor for an allowable PM BACT limit.

RBLC Review. The RBLC database lists the use of drift eliminators as the control method for similarly sized cooling towers.

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[106] Joel Reisman and Gordon Frisbie, *Calculating Realistic PM_{10} Emissions from Cooling Towers*, Environmental Progress, Vol. 21 Iss. 2 pgs. 127-130, April 20, 2004.

[107] U.S. EPA, Document Number AP-42, Compilation of Air Pollution Emission Factors, Vol. 1 Stationary and Area Sources, Chapter13: Miscellaneous Sources, Section 13.4 Wet Cooling Towers, 5th Edition, pp. 13.4-1 to 13.4-6.

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Selection of BACT. KU is proposing to utilize drift eliminators for the proposed mechanical cooling with a 0.001 percent drift rate. This drift rate is consistent with other recent BACT determinations. To demonstrate compliance with the proposed PM/PM_{10}/$PM_{2.5}$ BACT limits, KU will purchase high efficiency drift eliminators designed to achieve a drift rate of less than 0.001 percent of the circulating water flow rate.

8.5 GHG BACT for Equipment Leaks – Circuit Breaker

The project will result in fugitive GHG emissions from equipment leaks from the turbine circuit breaker (EU64) containing SF6.

8.5.1 Step 1 – Identification of Potential Control Techniques

Potentially available control options for reducing GHG emissions from the equipment leaks are:

- Component type/design
- Leak inspections (LDAR or AVO)
- Low-leaking components
- Use of non-SF_6 circuit breakers

8.5.2 Step 2 – Elimination of Technically Infeasible Control Options

Refer to Section 8.9.2 for a description of an LDAR program. The use of an LDAR program is a technically feasible control option for the fugitive GHG emissions at this source. AVO inspections provide a simplified method of leak detection through visual scanning for signs of leaks, listening for unusual sounds, and smelling for any odor.

The use of non-SF_6 insulating gas in the circuit breaker is technically feasible for specific low-voltage circuit breaker configurations. The proposed turbine circuit breaker for KU is 550 kilovolts (kV) all will require SF_6 as the insulating gas. Alternatives to SF_6 will not be discussed further.

8.5.3 Step 3 – Rank Remaining Control Technologies

A combination of component type/design, using low-leaking components, and LDAR or AVO inspections are the available technologies for the turbine circuit breaker.

8.5.4 Step 4 – Evaluation of Most Stringent Controls

Component type/design, using low-leaking components, and leak inspections are considered the most effective control available to reduce GHG emissions from the turbine circuit breaker. Although LDAR is an available action, given the very low level of emissions and small number of circuit breakers, the implementation of an LDAR program is cost prohibitive.

8.5.5 Step 5 – Selection of BACT

Based on this analysis, KU has determined for the control of GHG emissions with a maximum allowable leak rate of 0.5% SF_6 is BACT for the circuit breaker. Compliance with this BACT limit will be demonstrated by maintaining records from the leak rate calculations on an annual average.

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8.6 VOC BACT Analysis for Lube Oil Demister Vents

KU will operate a lube oil system with demister vents (EU65), with an approximate lube oil consumption of 0.5 gallons per day. There are no applicable NSPS to provide a baseline for the BACT analysis.

The annual potential emission rate from the demister vents is 0.7 tpy of VOC. No control options are available for reducing VOC emissions from these vents given the low concentration of emissions. Therefore, a full top-down BACT analysis is not warranted. KU proposes that there be no emission limit or monitoring required for the lube oil demister vents.

8.7 VOC and H_2SO_4 BACT Analysis for Storage Tanks

KU will operate one 300-gallon ULSFO storage tank (EU66) for the emergency generator, and one 3,733-gallon ULSFO storage tank (EU67) for the fire pump. Per vendor supplied data, annual throughput of the generator tank is 74,500 gallons per year, and the annual throughput of the fire pump is 10,779 gallons per year. As the maximum true vapor pressure of the ULSFO tanks is less than 0.25 psia, the tanks are exempt from the tank design requirements in NSPS Subpart Kc, therefore, there are no applicable NSPS to provide a baseline for the BACT analysis.

KU will operate one 12,200-gallon 93% sulfuric acid storage tank (EU70) with a maximum annual throughput of 146,400 gallons per year. There are no applicable NSPS to provide a baseline for the BACT analysis.

The annual potential emission rate from the generator storage tank is 8 E-3 tpy of VOC, and the annual potential emission rate from the fire pump storage tank is 4.2 E-5 tpy VOC. No control options are available for reducing VOC emissions from these tanks given the low concentration of emissions. Therefore, a full top-down BACT analysis is not warranted.

The annual potential emission rate from the sulfuric acid storage tank is 4.3 E-7 tpy of H_2SO_4. No control options are available for reducing H_2SO_4 emissions from this tank given the low concentration of emissions. Therefore, a full top-down BACT analysis is not warranted.

KU proposes that there be no emission limit or monitoring required for the storage tank at the facility.

8.8 PM BACT for Plant Roads

Fugitive PM emissions due to increased vehicle movement on new roads (EU68) as part of this project.

8.8.1 Step 1 – Identification of Potential Control Techniques

Potentially available control options for reducing PM emissions from the plant roads are:

- Paving roadways
- Sweeping roadways
- Wet or chemical suppression
- Good housekeeping

8.8.2 Step 2 – Elimination of Technically Infeasible Control Options

All control options identified are technically feasible.

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8.8.3 Step 3 – Rank Remaining Control Technologies

The control technologies are rated as follows:

- Paving roads reduces fugitive emissions from road dust versus leaving the roads unpaved
- Sweeping paved roads will limit dust fugitive emissions
- Wet suppression systems can be used on either paved or unpaved roads
- Good housekeeping practices will minimize dust fugitive emissions

8.8.4 Step 4 – Evaluation of Most Stringent Controls

All four options are technically feasible PM/PM_{10}/$PM_{2.5}$ control options and will be applied to achieve compliance with the proposed BACT limit.

8.8.5 Step 5 – Selection of BACT

Summary of Applicable Limits from NSPS/NESHAP/State Rules. The NGCC Haul Roads have no floor for an allowable PM BACT limit.

RBLC Review. The proposed BACT requirements are consistent with the control measures utilized for paved roads in the RBLC database.

Selection of BACT. All new roads associated with this project will be paved and the plant will use best management practices (e.g. road paving, sweeping, wet suppression systems and good housekeeping practices, etc.) to minimize fugitive dust emissions due to road traffic. KU will prepare an appropriate dust control plan and will utilize water or chemical suppression on an as needed basis to control dust emissions and will post speed limit signs. Records of control measures taken under the fugitive dust program will be maintained to demonstrate compliance.

8.9 VOC and GHG BACT for Natural Gas Piping Fugitives

The project will result in fugitive VOC and GHG emissions from equipment leaks from the piping components (EU69).

8.9.1 Step 1 – Identification of Potential Control Techniques

Potentially available control options for reducing VOC and GHG emissions from the equipment leaks are:

- Component type/design
- Leak inspections (LDAR or auditory, visual, olfactory [AVO] inspection)
- Low-leaking components

8.9.2 Step 2 – Elimination of Technically Infeasible Control Options

An LDAR program is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fittings, and sampling connections to name a few, basically any connections that could possibly leak in a process. LDAR is secondary to component type/design to minimize the potential for component leaks. LDAR is a work practice that is used to identify leaking equipment so the emissions can be reduced through systematic repair or replacement. The key to an effective program is regularly scheduled inspections and a defined repair/replacement schedule. The use of an LDAR program is a technically feasible control option for the fugitive VOC and GHG emissions at this source. AVO inspections provide a simplified

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method of leak detection through visual scanning for signs of leaks, listening for unusual sounds, and smelling for any NG odor.

8.9.3 Step 3 – Rank Remaining Control Technologies

A combination of component type/design using low-leaking components, and LDAR or AVO inspections are the only available technologies.

8.9.4 Step 4 – Evaluation of Most Stringent Controls

Component type/design, using low-leaking components, and leak inspections are considered the most effective control available to reduce the occurrence of fugitive emissions. Although LDAR is an available action, given the very low level of emissions and small number of fugitive piping components, the implementation of an LDAR program is cost prohibitive.

8.9.5 Step 5 – Selection of BACT

Based on this analysis, KU has determined that AVO inspections as a work practice are BACT for the control of VOC and GHG emission from equipment leaks from the piping. Compliance with this BACT limit will be demonstrated through recordkeeping of AVO inspection activities.

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9. SUMMARY OF BACT DETERMINATIONS

A top-down BACT analysis is required for each proposed emission unit emitting a pollutant for which PSD permitting requirements are triggered (NO_X, CO, VOC, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHGs). Detailed NO_X, CO, VOC, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG BACT determinations for the primary emission sources included in the project scope are presented in **Sections 6** through **8** of this application, alongside the detailed "top-down" BACT analysis for each source for the six (6) pollutant groupings. Table 9-1 through Table 9-5 below summarize the BACT determinations for each pollutant and source.

Table 9-1. Summary of NO_X BACT Determinations

MPEU Description	BACT Emission Limit		BACT Control Type
	Value	Units	
EU58 Unit 12 NGCC	2.0	ppm_{vd} (15% O_2) 30-day avg w/ or w/o DB Firing	• SCR and DLN Combustors
EU59 NG-Fired Auxiliary Boiler	0.036	lb/MMBtu 3-hr avg	• LNB/FGD and GCOP
EU60 NG-Fired Dewpoint Heater	0.038	lb/MMBtu	• LNB and GCOP
EU61 Diesel-Fired Engine	4.8	g NO_X+NMHC/hp-hr	• EPA Tier II certified engine
EU62 Diesel Pump/Engine	3.0	g NO_X+NMHC/hp-hr	• EPA certified engine

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Table 9-2. Summary of CO/VOC BACT Determinations

EU Description	BACT Emission Limit		Control Type
	Value	Units	
EU58 Unit 12 NGCC	2.0	ppm_{vd} CO (15% O_2) 30-day avg w/ or w/o DB Firing	• Oxidation catalyst and GCOP
	1.0	ppm_{vd} VOC (15% O_2) 3-hr avg w/o DB Firing	
	2.0	ppm_{vd} VOC (15% O_2) 3-hr avg w/ DB Firing	
EU59 Auxiliary Boiler	0.037	lb CO/MMBtu 3-hr avg	• GCOP
	0.0054	lb VOC/MMBtu 3-hr avg	
EU60 Dewpoint Heater	0.038	lb CO/MMBtu	• GCOP
	0.008	lb VOC /MMBtu	
EU61 Diesel-Fired Generator/Engine	2.6	g CO/hp-hr	• EPA certified engine
	4.8	g NO_X+NMHC/hp-hr	
EU62 Diesel-Fired Pump Engine	2.6	g CO/hp-hr	• EPA certified engine
	3.0	g NO_X+NMHC/hp-hr	
E65 Lube Oil Vents	N/A	N/A	• Mass balance
E66 Diesel Tank for Generator Engine	N/A	N/A	• Good operating practices
E67 Diesel Tank for Pump Engine	N/A	N/A	• Good operating practices
EU69 NG Piping Fugitives	N/A	N/A	• Auditory, visual, and olfactory inspection

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Table 9-3. Summary of PM/PM_{10}/$PM_{2.5}$ BACT Determinations

EU Description	BACT Emission Limit		Control Type
	Value	Units	
EU58 Unit 12 NGCC	0.005	lb/MMBtu w/ or w/o DB Firing	• Low sulfur fuel and GCOP
EU59 Auxiliary Boiler	0.007	lb/MMBtu (FPM+CPM PM, PM_{10}, and $PM_{2.5}$)	• GCOP
EU60 Dewpoint Heater	0.007	lb/MMBtu (FPM+CPM PM, PM_{10}, and $PM_{2.5}$)	• GCOP
EU61 Diesel-Fired Generator/Engine	0.15	g/hp-hr (PM, PM_{10}, and $PM_{2.5}$)	• EPA certified engine
EU62 Diesel Pump/Engine	0.15	g/hp-hr (PM, PM_{10}, and $PM_{2.5}$)	• EPA certified engine
EU63 Cooling Tower	N/A	N/A	• 0.001% drift loss
EU68 NGCC Roads	N/A	N/A	• BMPs (road paving, sweeping, wet suppression systems and good housekeeping practices)

Table 9-4. Summary of H_2SO_4 BACT Determinations

EU Description	BACT Emission Limit		Control Type
	Value	Units	
EU58 Unit 12 NGCC	0.5	gr S/100 scf	• Combustion of low sulfur pipeline quality NG and GCOP
EU59 Auxiliary Boiler	0.5	gr S/100 scf	• Combustion of low sulfur pipeline quality NG and GCOP
EU60 Dewpoint Heater	0.5	gr S/100 scf	• Combustion of pipeline quality NG and GCOP
EU70 Sulfuric Acid Tank	N/A	N/A	• Good operating practices

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Table 9-5. Summary of GHG BACT Determinations

EU Description	BACT Emission Limit		Control Type
	Value	Units	
EU58 Unit 12 NGCC	815	lb CO_2/MWh-g w/ DB Firing	• GCOP
	925	lb CO_2/MWh-g w/o DB Firing	
EU59 Auxiliary Boiler	117.1	lb CO_2e/MMBtu	• Fuel Selection • GCOP
EU60 Dewpoint Heater	117.1	lb CO_2e/MMBtu	• Fuel Selection • GCOP
EU61 Diesel-Fired Generator/Engine	163	lb CO_2e/MMBtu	• Fuel Selection • GCOP
EU62 Diesel Pump/Engine	163	lb CO_2e/MMBtu	• Fuel Selection • GCOP
EU64 Circuit Breakers	0.5	% leak rate	• Annual average Leak Rate Calculations
EU69 NG Piping Fugitives	N/A	N/A	• AVO Inspections

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APPENDIX A. MAPS AND PROCESS FLOW DIAGRAMS

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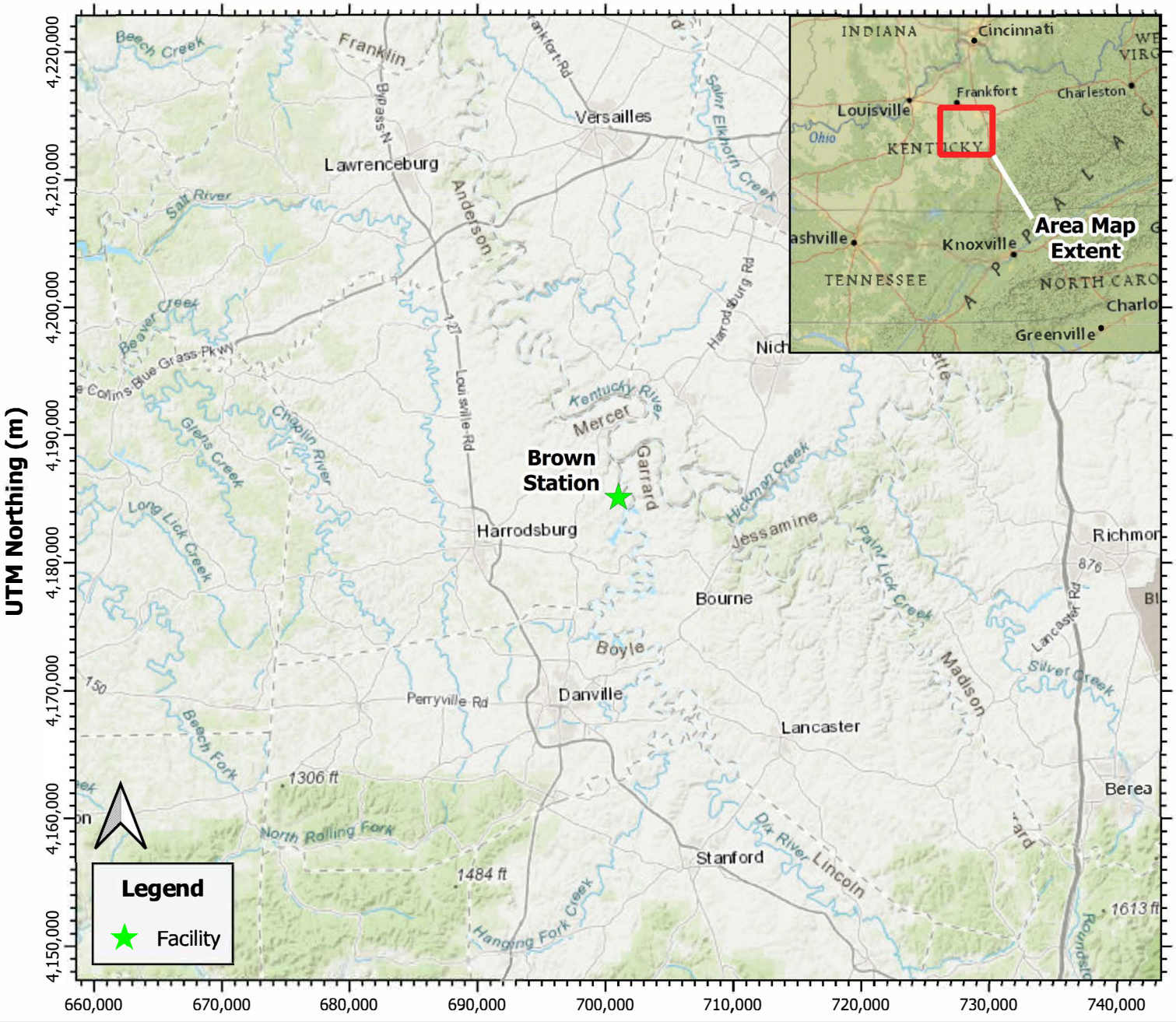


Figure A-1. Area Map for Brown Station in Harrodsburg KY

LG&E & KY | Harrodsburg, KY

All coordinates shown in
UTM Zone 16, NAD 83 Datum

Prepared By: Trinity Consultants

909 Wright's Summit Pkwy, Ste. 230
Project Number 241801.0040

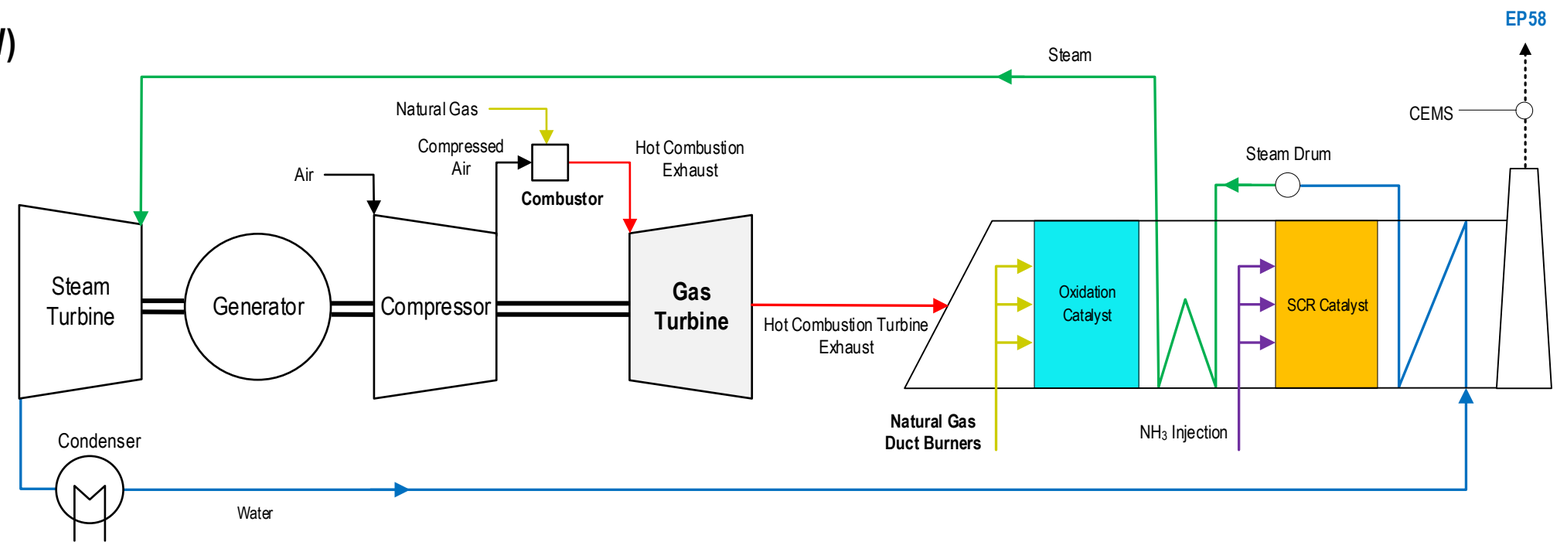
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Figure A-2 Air Permitting Process Flow Diagram

E.W. Brown Station

NGCC Turbine and Equipment (NEW)

Unit 12 Gas Turbine with HRSG
(681 MW Gross)
COMB19, 58 (1-6)
(Oxidation Catalyst – **C34**
SCR – **C35**)



EP59
Auxiliary Boiler
95.5 MMBtu/hr
COMB20, 59(1)
Natural Gas

EP60
Dewpoint Heater
16 MMBtu/hr
COMB21, 60(1)
Natural Gas

EP61
2 MW Genset Diesel Engine
2,923 bhp
COMB22, 61(1)
Diesel
EP66
Diesel Tank
3,733 gal
EQPT24, 66(1-2)

EP62
Diesel Fired Pump Engine
422 bhp
COMB23, 62(1)
Diesel
EP67
Diesel Tank
300 gal
EQPT25, 67(1-2)

EP63
10 Cell Cooling Tower
(with Drift Eliminators)
EQPT21, 63(1)

EP64
Turbine Circuit Breaker
EQPT22, 64(1)

EP65
Lube Oil System
EQPT23, 65(1)

EP70
93% Sulfuric Acid Tank
EQPT27, 70(1-2)

Natural Gas Piping Fugitives
EQPT26, 69(1-6)

NGCC Haul Roads
(Dust Suppression)
AREA5, 68(1-3)

Only new emission units affected by the proposed NGCC project are shown on this diagram. Refer to Section 1 in Appendix B for a complete inventory of emission units at Brown Station.

KyEIS IDs are shown in **green**. (Process IDs in parentheses)
KU defined emission points are shown in **blue**.
KU defined fugitive emissions are shown in **purple**.

New Emission Units with NGCC Project

Flow Legend
Process Flow
Gaseous or Emissions Flow

Air Permitting Process Flow Diagram for E.W. Brown Station
LG&E KU
PPL companies
Harrodsburg, Kentucky

Revised:
February 11, 2025
Project #
221801.0123

Trinity Consultants
909 Wright's Summit Pkwy, Ste. 230
Covington, KY 41011

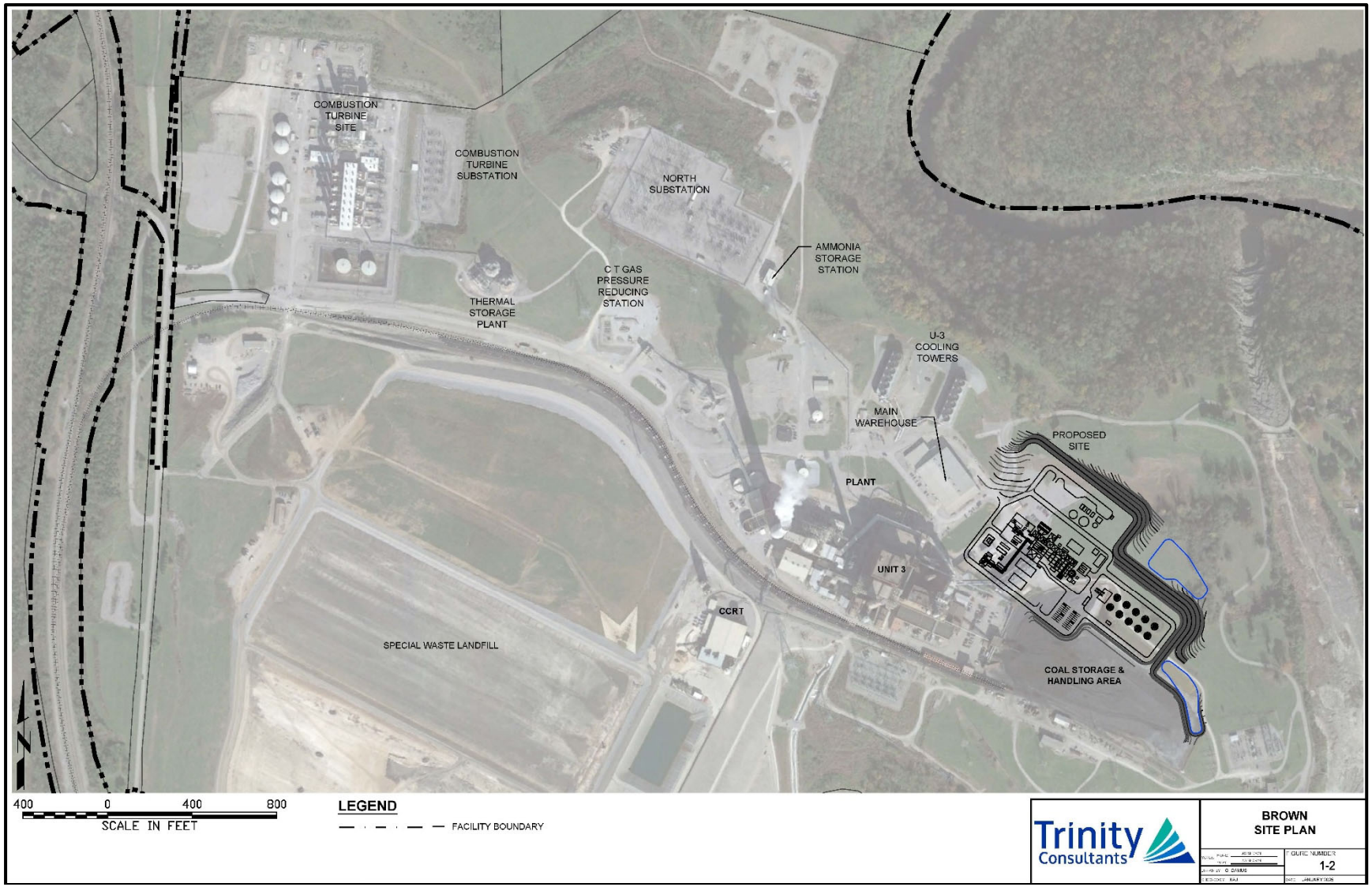
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Figure A-3. Brown Station Proposed NGCC Unit Site Map



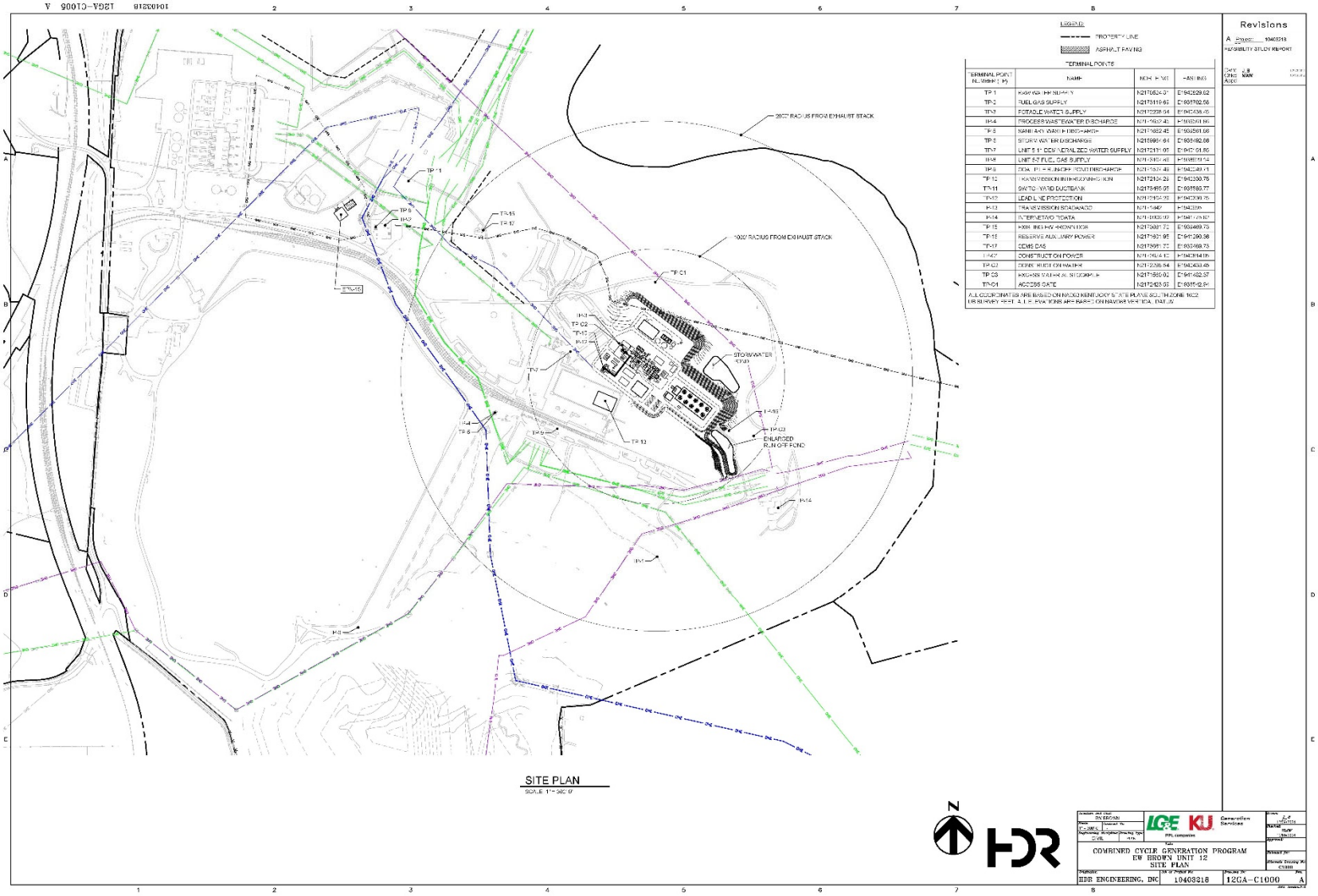
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Figure A-4. Existing Brown Station Components



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Figure A-5. Proposed Components of the NGCC Unit



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APPENDIX B. EMISSIONS UNIT INDEX AND CALCULATIONS

1. Brown Station Emission Unit Index

> The following table provides an index of existing emission units at the E.W. Brown Station along with new emission units requested for addition to the Title V permit upon permit renewal.
> The emission unit ID nomenclature listed for the new emission units (shown in green font) are placeholders, to be finalized by KDAQ upon issuance of an amended Title V operating permit.

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Project Impacts
35	AREA2	35	1	Paved and Unpaved Roads	Roadways	Dust Suppression		Fugitive	**Corrections made to process rate and emission factors**
50	AREA4	EU 50	1	CCR Landfill Operations and Haul Trucks	Unpaved Empty Bottom Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	2	CCR Landfill Operations and Haul Trucks	Paved Full Fly Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	3	CCR Landfill Operations and Haul Trucks	Unpaved Empty Gypsum-Like Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	4	CCR Landfill Operations and Haul Trucks	Unpaved Full Bottom Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	5	CCR Landfill Operations and Haul Trucks	Paved Empty Fly Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	6	CCR Landfill Operations and Haul Trucks	Unpaved Full Gypsum-Like Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	7	CCR Landfill Operations and Haul Trucks	Paved/Unpaved Empty Bottom Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	8	CCR Landfill Operations and Haul Trucks	Paved/Unpaved Full Bottom Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	9	CCR Landfill Operations and Haul Trucks	Paved/Unpaved Empty Fly Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	10	CCR Landfill Operations and Haul Trucks	Paved/Unpaved Full Fly Ash Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	11	CCR Landfill Operations and Haul Trucks	Paved/Unpaved Empty Gypsum-Like Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	12	CCR Landfill Operations and Haul Trucks	Paved/Unpaved Full Gypsum-Like Transport	Dust Suppression		Fugitive	
50	AREA4	EU 50	13	CCR Landfill Operations and Haul Trucks	Travel Heavy Equip. Landfill	Dust Suppression		Fugitive	
3	COMB3	003	1	Unit 3 Indirect Heat Exchanger	Coal	LowNOX; SCR; PJFF;	C03A, B, E, D	17	
3	COMB3	003	2	Unit 3 Indirect Heat Exchanger	#2 Fuel Oil	None		17	
23	COMB4	23	1	Combustion Turbine #9	Distillate Oil	CT9 Water Injection	C23	23	
23	COMB4	23	2	Combustion Turbine #9	Natural Gas	CT9 Water Injection	C23	23	
24	COMB5	24	1	Combustion Turbine #10	Distillate Oil	CT10 Water Injection	C24	24	
24	COMB5	24	2	Combustion Turbine #10	Natural Gas	CT10 Water Injection	C24	24	
25	COMB6	25	1	Combustion Turbine #8	Distillate Oil	CT8 Water Injection	C25	25	
25	COMB6	25	2	Combustion Turbine #8	Natural Gas	CT8 Water Injection	C25	25	
26	COMB7	26	1	Combustion Turbine #11	Distillate Oil	CT11 Water Injection	C26	26	
26	COMB7	26	2	Combustion Turbine #11	Natural Gas	CT11 Water Injection	C26	26	
27	COMB8	27	1	Combustion Turbine #6	Distillate Oil	CT6 Water Injection	C27	27	
27	COMB8	27	2	Combustion Turbine #6	Natural Gas	LowNOX Burners	C27	27	
28	COMB9	28	1	Combustion Turbine #7	Distillate Oil	CT7 Water Injection	C28	28	
28	COMB9	28	2	Combustion Turbine #7	Natural Gas	LowNOX Burners	C28	28	
29	COMB10	29	1	Combustion Turbine #5	Natural Gas	CT5 Water Injection	C29	29	
39	COMB11	39	1	Dix Dam Crest Gate Emergency Generator (40 HP)	Gasoline			39	
40	COMB12	40	1	Brown Station Emergency Generator (135 HP)	Diesel			40	
41	COMB12	41	1	CT5 Emergency Generator (308 HP)	Diesel			41	
42	COMB12	42	1	CT6 Emergency Generator (230 HP)	Diesel			42	
43	COMB12	43	1	CT7 Emergency Generator (230 HP)	Diesel			43	
44	COMB12	44	1	CT Area Fire Pump Engine (208 HP)	Diesel			44	
45	COMB13	45	1	Steam Plant Emergency Fire Pump Engine #1 (375 HP)	Diesel			45	
46	COMB13	46	1	Steam Plant Emergency Fire Pump Engine #2 (375 HP)	Diesel			46	
47	COMB14	47	1	Emergency Quench Water Pump Engine #1 (485 HP)	Diesel			47	
48	COMB14	48	1	Emergency Quench Water Pump Engine #2 (485 HP)	Diesel			48	
49	COMB15	49	1	Generac Emergency Engine (752 HP)	Diesel			49	
55	COMB16	EU 55	1	2.4 MMBtu/hr Natural Gas Process Heaters	Natural Gas			55	
56	COMB17	EU 56	1	7.0 MMBtu/hr Natural Gas Process Heaters	Natural Gas			56	
57	COMB18	EU 57	1	7.0 MMBtu/hr Natural Gas Process Heaters	Natural Gas			57	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Project Impacts
58	COMB19	58	1	Unit 12 Gas Turbine with HRSG and DB	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	S-58	New (COD 6/1/2030)
58	COMB19	58	2	Unit 12 Gas Turbine with HRSG and DB	Natural Gas Firing in GT	Oxidation Catalyst; SCR	C34, C35	S-58	New (COD 6/1/2030)
58	COMB19	58	3	Unit 12 Gas Turbine with HRSG and DB	Cold Startup Events			S-58	New (COD 6/1/2030)
58	COMB19	58	4	Unit 12 Gas Turbine with HRSG and DB	Warm Startup Events			S-58	New (COD 6/1/2030)
58	COMB19	58	5	Unit 12 Gas Turbine with HRSG and DB	Hot Startup Events			S-58	New (COD 6/1/2030)
58	COMB19	58	6	Unit 12 Gas Turbine with HRSG and DB	Shutdown Events			S-58	New (COD 6/1/2030)
59	COMB20	59	1	Auxiliary Steam Boiler	Natural Gas Combustion w/ LNB & FGR	NA		S-59	New (COD 6/1/2030)
60	COMB21	60	1	Fuel Gas (Dewpoint) Preheater	NG Fuel Combustion (15.65 MMBtu/hr)			S-60	New (COD 6/1/2030)
61	COMB22	61	1	2.18 MW Diesel Emergency Generator	Diesel Fuel Combustion			S-61	New (COD 6/1/2030)
62	COMB23	62	1	422 HP Diesel Driven Fire Pump	Diesel Fuel Combustion			S-62	New (COD 6/1/2030)
63	EQPT21	63	1	Mechanical Draft Cooling Tower (10 Cells)	Gallons of Recirculating Water	Drift Eliminators	C36	S-63	New (COD 6/1/2030)
64	EQPT22	64	1	Turbine Circuit Breaker with 30 lb. SF6 circuit	SF6 Releases			S-64	New (COD 6/1/2030)
65	EQPT23	65	1	Lube Oil System with Demister Vents	Evaporative losses	N/A	N/A	S-65	New (COD 6/1/2030)
66	EQPT24	66	1	Diesel Storage Tank for Generator (3,733 gal)	Breathing Losses	N/A	N/A	S-66	New (COD 6/1/2030)
66	EQPT24	66	2	Diesel Storage Tank for Generator (3,733 gal)	Working Losses	N/A	N/A	S-66	New (COD 6/1/2030)
67	EQPT25	67	1	Diesel Storage Tank for Firewater Pump (300 gal)	Breathing Losses	N/A	N/A	S-67	New (COD 6/1/2030)
67	EQPT25	67	2	Diesel Storage Tank for Firewater Pump (300 gal)	Working Losses	N/A	N/A	S-67	New (COD 6/1/2030)
68	AREA5	68	1	NGCC Haul Roads	Paved Aq. NH3 Transport	Dust Suppression		Fugitive	New (COD 6/1/2030)
68	AREA5	68	2	NGCC Haul Roads	Paved Cooling Twr Chemicals Transport	Dust Suppression		Fugitive	New (COD 6/1/2030)
68	AREA5	68	3	NGCC Haul Roads	Paved Water Treatment Chemicals Transport	Dust Suppression		Fugitive	New (COD 6/1/2030)
69	EQPT26	69	1	Natural Gas Piping Fugitives	Gas/Vapor Valves	N/A	N/A	Fugitive	New (COD 6/1/2030)
69	EQPT26	69	2	Natural Gas Piping Fugitives	Relief Valves	N/A	N/A	Fugitive	New (COD 6/1/2030)
69	EQPT26	69	3	Natural Gas Piping Fugitives	Flanges	N/A	N/A	Fugitive	New (COD 6/1/2030)
69	EQPT26	69	4	Natural Gas Piping Fugitives	Vents	N/A	N/A	Fugitive	New (COD 6/1/2030)
69	EQPT26	69	5	Natural Gas Piping Fugitives	Compressors Components	N/A	N/A	Fugitive	New (COD 6/1/2030)
69	EQPT26	69	6	Natural Gas Piping Fugitives	Sampling Connections	N/A	N/A	Fugitive	New (COD 6/1/2030)
70	EQPT27	70	1	93% Sulfuric Acid Tank	Breathing Losses	N/A	N/A	S-70	New (COD 6/1/2030)
70	EQPT27	70	2	93% Sulfuric Acid Tank	Working Losses	N/A	N/A	S-70	New (COD 6/1/2030)
21 (16)	EQPT2	21	1	Dry Fly Ash Handling	Dry Fly Ash Collection and Silo	PJFF	C21	21	
7-1	EQPT14	07	1	Coal Handling Operations 07	West Track Hopper	Enclosures	C07A	Fugitive	
7-2	EQPT14	07	2	Coal Handling Operations 07	Conveyor A-1	Enclosures	C07B	Fugitive	
~~7-3~~	~~EQPT14~~	~~07~~	~~3~~	~~Coal Handling Operations 07~~	~~Conveyor E~~	~~Enclosures~~	~~C07C~~	~~Fugitive~~	To be removed from site.
7-4	EQPT14	07	4	Coal Handling Operations 07	Conveyor F	Enclosures	C07D	Fugitive	
7-5	EQPT14	07	5	Coal Handling Operations 07	Conveyor G	Enclosures	C07E	Fugitive	
7-6	EQPT14	07	6	Coal Handling Operations 07	Conveyor H	Enclosures	C07F	Fugitive	
9-1	EQPT15	09	1	Coal Handling Operations 09	East Track Hopper	Enclosures	C09A	Fugitive	
9-2	EQPT15	09	2	Coal Handling Operations 09	Conveyor A	Enclosures	C09B	Fugitive	
9-3	EQPT15	09	3	Coal Handling Operations 09	Conveyor B	Enclosures	C09C	Fugitive	
~~9-4~~	~~EQPT15~~	~~09~~	~~4~~	~~Coal Handling Operations 09~~	~~Conveyor C~~	~~Enclosures~~	~~C09D~~	~~Fugitive~~	To be removed from site.
9-5	EQPT15	09	5	Coal Handling Operations 09	Conveyor J	Enclosures	C09E	Fugitive	
9-6	EQPT15	09	6	Coal Handling Operations 09	Coal Stockpile	Dust Suppression	C09F	Fugitive	
~~13-1~~	~~EQPT16~~	~~13~~	~~1~~	~~Coal Handling Operations 13~~	~~Conveyor D [Tripper for Units 1 & 2]~~	~~Enclosure~~	~~C13A~~	~~13~~	To be removed from site.
13-2	EQPT16	13	2	Coal Handling Operations 13	Conveyor K-1 [Upper Tripper for Unit 3]	Fabric Filter	C13B	14	
13-3	EQPT16	13	3	Coal Handling Operations 13	Conveyor K [Lower Tripper for Unit 3]	Fabric Filter	C13C	15	
30	EQPT17	30-31	1	Limestone Unloading	Limestone Truck Dump Station #1	Fabric Filter	C30	30	
31	EQPT17	30-31	2	Limestone Unloading	Limestone Truck Dump Station #2	Fabric Filter	C31	31	

Title V EU ID	KyEIS Equip ID	KyEIS Source ID	KyEIS Process ID	Emission Unit Description	KyEIS Process Description	Control Description	Control ID(s)	Emission Point ID	Project Impacts
32	EQPT18	32-34	1	Limestone Handling	Limestone Stacking Tube	Fabric Filter	C32	32	
33-34	EQPT18	32-34	2	Limestone Handling	Limestone Reclaim Conveyor #1 & 2	Fabric Filter	C33	33	
38	EQPT19	36-38	3	Cooling Tower 3 (Forced Draft)	Unit 3 Cooling Tower with Drift Eliminators	Drift Eliminators		36	
51 & 52	EQPT20	51	1	2 Cummins Emergency Engines (1220 HP Each)	Diesel			51	
IA-01				Station fuel-oil tanks (2 @ 1,100,000 gallons each) - T-1 & T-2 (South CT area)					
IA-02				#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973 - T-10 525,000 (Fuel oil Storage & Unit 3 Light off Tank)					
IA-03				Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each) - T-17 & T-18 (Steam Plant/Unit 3 Clean/Dirty Turbine Oil)					
IA-04				Unleaded gasoline storage tanks - T-25(Coal Yard/Tractor Garage Area)					
IA-05				Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons) - R3, R6, R7					
IA-06				Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons) - R8, R9, R10, R11					
IA-07				Burning of Off-Specification Used Oil for Energy Recovery					
IA-08				Kerosene Tank (500 gallons) - T-26 (Coal Yard/Tractor Garage Area)					
IA-09				Distillate Oil and/or Propane Coal Belt Heaters					
IA-10				Limestone Storage Pile					
IA-11				Limestone Reclaim Maintenance Tunnel Exhaust Vent					
IA-12				Sorbent Storage Silos (for SO3 mitigation)					
IA-13				Natural Gas Distillate tank (2,000 gallons) - T-9 (CT area)					
IA-14				Diesel Fuel tanks for emergency generators (3 @ 391 gallons) - T3, T4, T5 (CT area/Emergency Generators)					
IA-15				Diesel Fuel tank for emergency fire pump (300 gallons) - T-8 (CT area/emergency fire pump AST)					
IA-16				Liquid Hg Control Additives					
IA-17				Diesel Fuel tank for emergency generator (837 gallons) - T-14 (Steam Plant/Unit 3 Emergency Generator)					
IA-18				Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons) - T-20, T-21 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)					
IA-19				Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons) - T-22, T-23 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)					
IA-20				Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons) - R4, R44					
IA-21				Turbine oil reservoir for Unit 3 seal oil (150 gallons) - R14					
IA-22				Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons) - R18, R19 (Unit 3, outside out of service ESP)					
IA-23				Lab Fume Hood					
IA-24				Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons) - T27, T28, T29 (Tractor Garage Building Read Area)					
IA-25				PAC Storage Silos					
IA-26				Bottom Ash Transport					
IA-27				Fly Ash Transport					
IA-28				Gypsum Transport & Process Water System Solids					
IA-29				Landfill Truck Loading and Unloading & Process Water System Solids					
IA-30				Active Area of the CCR Landfill & Process Water System Solids (Wind Erosion)					
IA-31				Slipstream Carbon Dioxide (CO2) capture System – Research					
IA-32				Bottom Ash Handling including storage pile (associated with CCR landfill operations)					
IA-33				Fly Ash Handling including load out to trucks (associated with CCR landfill operations)					
IA-34				Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)					
IA-35				Fly Ash Storage Silos (2) (associated with CCR landfill operations)					
IA-36				Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)					
IA-37				NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)					
IA-38				Diesel Fuel tanks for emergency generators (2 @ 900 gallons) - T-6, T-7 CT area/between CT7 & CT8(EU28 & EU25)					
IA-39				Diesel Fuel Tanks (500, 2000, 3@ 550, 1100 gallons) - T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)					
IA-40				Mobile Diesel Fuel Tank (251 gallons/square tank) - T-39 (Stored in CT Warehouse when not in use)					
IA-41				**Unit 3 Propylene Glycol Tank (3,000 gal)**					
IA-42				**Hydroelectric Building Lube Oil Tanks (T-31 and T-32)**					
IA-43				**CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)**					
IA-44				**Unit 3 Hydrazine Monohydrate Tote (180 gal)**					
IA-45				**Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)**					

2. Potential Emissions Summary for New NGCC Project Emission Units

> The table below tallies the potential to emit for all new emission units associated with the proposed NGCC Project for all relevant regulated air pollutants.

KyEIS Equip ID	KyEIS Source ID	Description	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	Lead (tpy)	CO_2e (tpy)
New Emission Units												
COMB19	58	Unit 12 Gas Turbine with HRSG and DB	98.92	98.92	98.92	151.38	134.60	64.64	26.86	23.69	8.97E-04	2,289,968
COMB20	59	Auxiliary Steam Boiler	1.30	1.30	1.30	6.96	7.06	1.00	0.26	0.020	9.07E-05	22,370
COMB21	60	Fuel Gas (Dewpoint) Preheater	0.23	0.23	0.23	2.50	2.53	0.53	0.093	0.007	3.25E-05	7,821
COMB22	61	2.18 MW Diesel Emergency Generator	0.24	0.24	0.24	7.49	4.15	0.20	0.008	0	0	841
COMB23	62	422 HP Diesel Driven Fire Pump	0.03	0.03	0.03	0.86	0.60	0.05	0.001	0	0	121
EQPT21	63	Mechanical Draft Cooling Tower (10 Cells)	2.06	0.97	0.0042							
EQPT22	64	Turbine Circuit Breaker with 30 lb. SF6 circuit										1.8
EQPT23	65	Lube Oil System with Demister Vents						0.66				
EQPT24	66	Diesel Storage Tank for Generator (3,733 gal)						7.85E-03				
EQPT25	67	Diesel Storage Tank for Firewater Pump (300 gal)						4.17E-05				
AREA5	68	NGCC Haul Roads	0.24	0.05	0.01							
EQPT26	69	Natural Gas Piping Fugitives						0.07				415
EQPT27	70	93% Sulfuric Acid Tank								4.34E-07		
Subtotal			103.0	101.7	100.7	169.2	148.9	67.2	27.2	23.7	1.02E-03	2,321,537

Emission Unit ID		Description	NH3 (tpy)	Acetalde-hyde (tpy)	Formalde-hyde (tpy)	Hexane (tpy)	Toluene (tpy)	Xylenes (tpy)	Nickel (tpy)	Chromium (tpy)	Mercury (tpy)	Total HAP (tpy)
New Emission Units												
COMB19	58	Unit 12 Gas Turbine with HRSG and DB	137.98	3.06	4.01	1.61	1.13	0.56	3.77E-03	2.51E-03	4.67E-04	11.07
COMB20	59	Auxiliary Steam Boiler			1.4E-02	0.33	6.2E-04		3.81E-04	2.54E-04	4.72E-05	0.34
COMB21	60	Fuel Gas (Dewpoint) Preheater			4.9E-03	0.117	2.2E-04		1.37E-04	9.11E-05	1.69E-05	0
COMB22	61	2.18 MW Diesel Emergency Generator		1.3E-04	4.0E-04		1.4E-03	9.9E-04				8.7E-03
COMB23	62	422 HP Diesel Driven Fire Pump		5.7E-04	8.7E-04		3.0E-04	2.1E-04				2.9E-03
EQPT21	63	Mechanical Draft Cooling Tower (10 Cells)										
EQPT22	64	Turbine Circuit Breaker with 30 lb. SF6 circuit										
EQPT23	65	Lube Oil System with Demister Vents										
EQPT24	66	Diesel Storage Tank for Generator (3,733 gal)										
EQPT25	67	Diesel Storage Tank for Firewater Pump (300 gal)										
AREA5	68	NGCC Haul Roads										
EQPT26	69	Natural Gas Piping Fugitives										
EQPT27	70	93% Sulfuric Acid Tank										
Subtotal			137.98	3.06	4.03	2.06	1.13	0.56	0.0043	0.0029	0.0005	11.42

3. Project Net Emissions Increase Summary Table

> The table below tallies the net emission increases associated with the proposed NGCC Project for all relevant regulated NSR polutants and compares them to the PSD Significant Emission Rate thresholds. Values shown for new emission units are their potential emissions, taking into account inherent and proposed operating limitations and control device configurations. Values shown for the emission units being shutdown as part of the project (if any) are their baseline actual emissions calulated in accordance with 401 KAR 51:001 Section 1(20)(a).

KyEIS Equip ID	KyEIS Source ID	Description	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	Lead (tpy)	CO_2e (tpy)
New Emission Units												
COMB19	58	Unit 12 Gas Turbine with HRSG and DB	98.92	98.92	98.92	151.38	134.60	64.64	26.86	23.69	8.97E-04	2,289,968
COMB20	59	Auxiliary Steam Boiler	0.34	1.30	1.30	6.96	7.06	1.00	0.26	0.020	9.07E-05	22,370
COMB21	60	Fuel Gas (Dewpoint) Preheater	0.12	0.23	0.23	2.50	2.53	0.53	0.093	0.007	3.25E-05	7,821
COMB22	61	2.18 MW Diesel Emergency Generator	0.24	0.24	0.24	7.49	4.15	0.20	0.008	0	0	841
COMB23	62	422 HP Diesel Driven Fire Pump	0.03	0.03	0.03	0.86	0.60	0.05	0.001	0	0	121
EQPT21	63	Mechanical Draft Cooling Tower (10 Cells)	2.06	0.97	4.16E-03	0	0	0	0	0	0	0
EQPT22	64	Turbine Circuit Breaker with 30 lb. SF6 circuit	0	0	0	0	0	0	0	0	0	1.8
EQPT23	65	Lube Oil System with Demister Vents	0	0	0	0	0	0.66	0	0	0	0
EQPT24	66	Diesel Storage Tank for Generator (3,733 gal)	0	0	0	0	0	7.85E-03	0	0	0	0
EQPT25	67	Diesel Storage Tank for Firewater Pump (300 gal)	0	0	0	0	0	4.17E-05	0	0	0	0
AREA5	68	NGCC Haul Roads	0.24	0.05	0.01	0	0	0	0	0	0	0
EQPT26	69	Natural Gas Piping Fugitives	0	0	0	0	0	0.07	0	0	0	414.57
EQPT27	70	93% Sulfuric Acid Tank	0	0	0	0	0	0	0	4.34E-07	0	0
Subtotal			102.0	101.7	100.7	169.2	148.9	67.2	27.2	23.7	1.02E-03	2,321,537
Emission Changes from Existing Unmodified Emission Units												
SubTotal			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emissions Increase Summary												
Net Project Emission Increases			**102.0**	**101.7**	**100.7**	**169.2**	**148.9**	**67.2**	**27.2**	**23.7**	**0.0**	**2,321,537**
PSD/NSR Major Modification Threshold			25	15	10	40	100	40	40	7	0.6	75,000
Trigger PSD/NSR?			**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**No**	**Yes**	**No**	**Yes**

* CO2e (GHG Pollutants) only become subject to regulation and potentially applicable to PSD if another regulated NSR pollutant triggers PSD

4. Unit 12 Gas Turbine with HRSG/Duct Burners - Emission Calculations

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 58: Unit 12 Gas Turbine with HRSG and DB are documented in this section. Note that the detailed emissions calculations in this section are representative of a single GT to be installed as part of the NGCC EGU Project.

Equipment ID (SI): **58**
Emission Unit Description: Unit 12 Gas Turbine with HRSG and DB
Equipment ID (SI): COMB19

4.1 Process Unit(s)

> The new emission unit identification and associated process IDs proposed to be assigned within the KyEIS for the GT are shown below. The GT can fire natural gas without the duct burner (DB) (Process ID 1), and when needed, both the GT and DB will be fired with natural gas (Process ID 2). Process IDs 3 through 6 encompass possible startup and shutdown operating events, consistent with conventional approaches for representing emissions from the combustion turbine.

Process ID: **1**
EU ID - PID: **58-1**
Process Description: **Natural Gas Firing in GT & DB**
Control Device ID: C34, C35
Control Device Description: Oxidation Catalyst; SCR
Stack ID: S-58
Stack Description: Vertically Unobstructed Stack
Applicable Regulation: 401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)

Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20100201
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Natural Gas (2-01-002) - Turbine (2-01-002-01)
SCC Units: Million Cubic Feet Natural Gas Burned

Process ID: **2**
EU ID - PID: **58-2**
Process Description: **Natural Gas Firing in GT**
Control Device ID: C34, C35
Control Device Description: Oxidation Catalyst; SCR
Stack ID: S-58
Stack Description: Vertically Unobstructed Stack
Applicable Regulation: 401 KAR 51:017, 59:015, 60:005 (NSPS KKKK & TTTTa), 63:002 (NESHAP YYYY), 52:060, 51:240, 51:260, 40 CFR 75, 40 CFR 97 (AAAAA, CCCCC, & EEEEE)

Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20100201
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Natural Gas (2-01-002) - Turbine (2-01-002-01)
SCC Units: Million Cubic Feet Natural Gas Burned

Process ID:	**3**	**4**	**5**	**6**
EU ID - PID:	**58-3**	**58-4**	**58-5**	**58-6**
Process Description:	**Cold Startup Events**	**Warm Startup Events**	**Hot Startup Events**	**Shutdown Events**
Control Device ID:	N/A	N/A	N/A	N/A
Control Device Description:	0	0	0	0
Stack ID:	S-58	S-58	S-58	S-58
Stack Description:	Vertically Unobstructed Stack	Same	Same	Same
Applicable Regulation:	401 KAR 51:017	401 KAR 51:017	401 KAR 51:017	401 KAR 51:017
Construction Date:	6/22/2026	6/22/2026	6/22/2026	6/22/2026
Fugitive Emissions?	No	No	No	No
Count Emissions for PTE?	Yes	Yes	Yes	Yes
Source Classification Code				
SCC:	39999993	39999993	39999993	39999993
SCC Description:	Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Industrial Processes (3-99-999) - Other Not Classified (3-99-999-93)			
SCC Units:	Each Parts Processed			

4.2 Capacity and Fuel Information for 58-1, Natural Gas Firing in GT & DB

> The following provides the capacity information for the GT/DB, as well as other relevant information used in the emissions estimates. The term "unfired" means without DB, and "fired" means both GT + DB.

Natural Gas Higher Heating Value (HHV)	1,053 Btu/scf	Average for Brown Inlet Gas
Natural Gas HHV used for AP-42 1.4 & 3-1	1,020 Btu/scf	
Natural Gas HHV used for 40 CFR 98, Subpart C	1,026 Btu/scf	
Maximum operating hours/yr used in permitting	8,760 hr/yr	
SS operating hours/yr accounting for SUSD events	*7,470 hr/yr*	*Although not used in calculations, this is the actual estimate of operating hours IF KU excluded time for every SUSD event and the minimum time in between events*
NGCC in "Fired" Mode (EU58-1)		
Maximum Heat Input Capacity Used for Emission Calculations	**4,525** MMBtu/hr	*Maxiumum CT Heat Input (HHV basis) from specs for NG firing (GE Case EC-1)*
Maximum Fuel Consumption	4.297 MMscf/hr	= 4,525 MMBtu/hr / 1,053 Btu/scf
Maximum Fuel Consumption	37,641 MMscf/yr	= 8,760 hr/yr * 4.297 MMscf/hr
Maximum Heat Input Capacity of DB only	**431.4** MMBtu/hr	*Maximum DB Heat Input (HHV basis) from specs for NG firing (GE Case EH-1)*
Maximum Fuel Consumption	0.410 MMscf/hr	= 4,525 MMBtu/hr / 1,053 Btu/scf
Maximum Fuel Consumption	3,588 MMscf/yr	= 8,760 hr/yr * 0.410 MMscf/hr
NGCC in "Unfired" Mode (EU58-2)		
Maximum Heat Input Capacity Used for Emission Calculations	**3,969** MMBtu/hr	*Maxiumum CT Heat Input (HHV basis) from specs for NG firing (GE Case EC-3)*
Maximum Fuel Consumption	3.770 MMscf/hr	= 4,525 MMBtu/hr / 1,053 Btu/scf
Maximum Fuel Consumption	33,022 MMscf/yr	= 8,760 hr/yr * 4.297 MMscf/hr

4.3 Derivation and Documentation of Steady-State Operation Emission Factors for Natural Gas Firing in GT & DB (58-1)

4.3.1 NSR-Regulated Pollutants

> Controlled emission factors (EFs) for all NSR-regulated pollutants have been calculated for the worst-case annual operating profile while the GT is operating and duct burners are fired as provided by the vendor, labeled herein as "fired". Any deviations from the vendor estimates are noted below. Lead emissions are discussed in the HAP subsection below.

NO_X

Concentration in stack exhaust after SCR	**2.0**	ppmvd @ 15% O2	KU's vendor guarantee requirement for fired GT
Controlled Emission Factor	7.922	lb/MMscf	= 34.04 lb/hr / 4.297 MMscf/hr
Controlled Emission Rate	**34.04**	lb/hr	Max lb/hr from vendor specs for fired NG firing (GE Case EC-1)
Control Efficiency (**not guaranteed**)	90	%	Nominal value for a SCR selected for purposes of defining an uncontrolled emission factor. Estimated efficiency of 94% from provided unit specifications.
Uncontrolled Emission Factor	79.219	lb/MMscf	= 7.922 lb/MMscf / (100% - 90%)

CO

Concentration in stack exhaust after oxidation catalyst	**2.0**	ppmvd @ 15% O2	KU's vendor guarantee requirement for fired GT
Controlled Emission Factor	4.823	lb/MMscf	= 20.72 lb/hr / 4.297 MMscf/hr
Controlled Emission Rate	**20.72**	lb/hr	Max lb/hr from vendor specs for fired NG firing (GE Case EC-1)
Control Efficiency (**not guaranteed**)	90	%	Nominal value for a oxidation catalyst
Uncontrolled Emission Factor	48.232	lb/MMscf	= 4.823 lb/MMscf / (100% - 90%)

VOC

Concentration in Stack Exhaust (as methane)	**2.0**	ppmvd @ 15% O2	KU's vendor guarantee requirement for fired GT
Controlled Emission Factor	2.763	lb/MMscf	= 11.87 lb/hr / 4.297 MMscf/hr
Controlled Emission Rate	**11.87**	lb/hr	Max lb/hr from vendor specs for fired NG firing (GE Case EC-1)
Control Efficiency (**not guaranteed**)	50	%	Based on expected VOM control efficiency from catalytic oxidation.
Uncontrolled Emission Factor	5.525	lb/MMscf	= 2.763 lb/MMscf / (100% - 50%)

SO_2

> Vendor was told that the pipeline tariff is based on a sulfur content on 0.5 gr/100 scf (Cscf), and the highest sulfur measured in the last 5 years was 0.116 gr/Cscf. The following estimate is based solely on a maximum sulfur input of 0.5 gr/Cscf and 100% conversion from S to SO2. In reality, the SO2 should be reduced by the amount of SO2 converted to SO3, which can be converted further to H2SO4, (NH4)2SO4, and/or (NH4)HSO4. For simplicity, the following methodology does not account for these further reductions and thus the emission estimates are conservative.

Max sulfur content for pipeline gas	0.5	gr/Cscf	
Molecular Weight of S	32.07	lb/lbmol	
Molecular Weight of SO2	64.07	lb/lbmol	
Uncontrolled Emission Rate	6.13	lb/hr	= 0.5 lb/Cscf x 10,000 Cscf/MMscf / 7,000 gr/lb / 1,053 x 4,525 MMBtu/hr x 64.07 lb /lbmol SO2 / 32.07 lb/lbmol S x 1 lbmol SO2/1 lbmol S x 100%
Uncontrolled Emission Factor	1.427	lb/MMscf	= 6.13 lb/hr / 4.297 MMscf/hr
Uncontrolled Emission Factor	0.0014	lb/MMBtu	= 6.13 lb/hr / 4,525 MMBtu/hr

H_2SO_4

> Within the combustion process, SO_2 can be further oxidized into SO_3, which then can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. This conversion is influenced by the sulfur content in the fuel, ambient temperature/relative humidity, evaporative cooling operation, duct burner operation, oxidation over the oxidation catalyst, oxidation within the SCR, available moisture, ammonia slip concentration, acid dew point, etc. The estimates below are based on data provided by the equipment vendor.

Molecular Weight of H2SO4	98.08	lb/lbmol	
Uncontrolled Emission Rate	**5.41**	lb/hr	Max lb/hr from vendor specs for fired NG firing (GE Case EC-1)
Uncontrolled Emission Factor	1.259	lb/MMscf	= 5.41 lb/hr / 4.297 MMscf/hr
Uncontrolled Emission Factor	0.0012	lb/MMBtu	= 5.41 lb/hr / 4,525 MMBtu/hr

$PM/PM_{10}/PM_{2.5}$

> Steady-state generation of PM should be negligible from this NGCC system. When KU asked GE to provide PM estimates, GE provided overly conservative estimates of PM (not guarantees). Given the presence of the oxidation catalyst system, formation of condensable PM (CPM) and sub-micron filterable PM is a possibility under certain conditions. One pathway is the sulfate formation from H2SO4, (NH4)2SO4, and/or (NH4)HSO4, as well as the nitrate formation in the form of NH4NO3. However, the PM emissions from these pathways are still expected to be low. Regardless, given uncertainties, KU conservatively used the information provided by the GE for defining PM emissions. In all cases, all PM can be assumed to be less than 2.5 µm in mean diameter (i.e., PM = PM10 = PM2.5).

Uncontrolled Emission Rate	**22.58**	lb/hr	Max lb/hr from vendor specs for fired NG firing (GE Case EH-1)
Uncontrolled Emission Factor	5.256	lb/MMscf	= 22.58 lb/hr / 4.297 MMscf/hr
Uncontrolled Emission Factor	0.0050	lb/MMBtu	= 5.256 lb/MMscf / 1,053 Btu/scf

Greenhouse Gases

> Emission factors are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Table C-1).

> The global warming multiplying factors for CH4 and N2O are those specified in 40 CFR 98 Subpart A. These are used to calculate the overall CO2e emissions.

CO_2

Uncontrolled Emission Factor	117	lb/MMBtu	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	120,019	lb/MMscf	= 116.98 lb/MMBtu * 1,026 MMBtu/MMscf
Uncontrolled Emission Rate	515,709	lb/hr	= 120,019 lb/MMscf x 4.297 MMscf/hr

CH_4

Uncontrolled Emission Factor	0.0243	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 1.1 x 10^{-2} kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	24.881	lb/MMscf	= 0.0243 lb/MMBtu * 1,026 MMBtu/MMscf
Uncontrolled Emission Rate	106.91	lb/hr	= 24.881 lb/MMscf x 4.297 MMscf/hr

N_2O

Uncontrolled Emission Factor	0.0035	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 1.6 x 10^{-3} kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	3.619	lb/MMscf	= 0.0035 lb/MMBtu * 1,026 MMBtu/MMscf
Uncontrolled Emission Rate	15.55	lb/hr	= 3.619 lb/MMscf x 4.297 MMscf/hr

CO_2e

Global Warming Potentials of GHGs per amendment to 40 CFR 98, Subpart A (89 FR 31894, published April 25, 2024)

CO2	1		
CH4	28		89 FR 42218, May 14, 2024
N2O	265		89 FR 42218, May 14, 2024
Uncontrolled Emission Factor	121,674	lb/MMscf	(CO2 EF) + (CH4 EF x CH4 GWP) + (N2O EF x N2O GWP)
Uncontrolled Emission Rate	522,824	lb/hr	= 121,674 lb/MMscf x 4.297 MMscf/hr

Process ID 1: Steady-State Operation GTs with DBs

	Uncontrolled EF (lb/MMscf)	Basis	Uncontrolled Emissions (lb/hr)	(tpy)	~Control Efficiency	Controlled Emissions (lb/hr)	(tpy)
Regulated Pollutants							
NOX	79.219	KU Requirement	340.4	1,490.9	90%	34.0	149.1
CO	48.232	KU Requirement	207.2	907.7	90%	20.7	90.8
VOC	5.525	KU Requirement	23.7	104.0	50%	11.87	52.0
PM	5.256	Vendor Estimate	22.6	98.9		22.6	98.9
PM10	5.256	Vendor Estimate	22.6	98.9		22.6	98.9
PM2.5	5.256	Vendor Estimate	22.6	98.9		22.6	98.9
SO2	1.427	Pipeline spec conversion	6.1	26.9		6.13	26.9
H2SO4	1.259	Pipeline spec conversion	5.4	23.7		5.41	23.7
NH3	7.332	KU Requirement	31.5	138.0		31.5	138.0
CO2	120,019	40 CFR 98, Table C-1	515,709	2,258,806		515,709	2,258,806
CH4	24.881	40 CFR 98, Table C-2	106.913	468.3		106.9	468.3
N2O	3.619	40 CFR 98, Table C-2	15.551	68.1		15.6	68.1
CO2e	121,674	40 CFR 98 Subpart A	522,824	2,289,968		522,824	2,289,968

4.3.2 Ammonia (from Ammonia Slip in SCR)

NH_3

Concentration in stack exhaust	**5.0**	ppmvd @ 15% O2	KU's vendor requirement for fired GT
Uncontrolled Emission Factor	7.332	lb/MMscf	= 31.5 lb/hr / 4.297 MMscf/hr
Uncontrolled Emission Rate	31.50	lb/hr	Max lb/hr from vendor specs for fired NG firing (GE Case EC-1)

4.3.3 Hazardous Air Pollutants for GT

Formaldehyde

Concentration in stack exhaust	0.091	ppmvd @ 15% O2	KU's vendor requirement per 40 CFR §63.6100 and Table 1 of NESHAP YYYY
Molecular weight of HCHO	30.031	lb/lbmol	
Oxygen based F-Factor	8,638	dscf/MMBtu	RM Method 19 determination of Fd factor for natural gas combustion can use a default value of 8,710, or use equations 19-13 through 19.15. KU chose to use GE's derived Fd at ~8,638 dscf/MMBtu.
Controlled Emission Rate	1.01	lb/hr	= 1.0 atm STD x 30.031 lb/lbmol HCHO / 0.7302 ft3-atm/lbmol-°R / 527.67°R STD x 0.091 ppmvd @ 15% O2 /1E6 x 8,638.0 dscf/MMBtu x (20.9/(20.9-15) x 4,525 MMBtu/hr x 1.031 safety factor
Controlled Emission Factor	0.236	lb/MMscf	= 1.01 lb/hr / 4.297 MMscf/hr

> Other than for formaldehyde (described above), emission factors for organic and metallic HAP emissions from natural gas-fired turbines published in AP-42, Section 3.1 are used to estimate potential emissions.

Pollutant	CAS No.	GT Uncontrolled EF (lb/MMBtu)	GT Uncontrolled EF (lb/MMscf)	Oxidation Catalyst CE[4] (%)	GT After Oxidation Catalyst EF (lb/MMBtu)	GT After Oxidation Catalyst EF (lb/MMscf)	Basis	Note
1,3-Butadiene	106-99-0	4.3E-07	4.386E-04	50%	2.2E-07	2.2E-04	AP-42 Table 3.1	2
Acetaldehyde	75-07-0	3.5E-04	3.590E-01	50%	1.8E-04	1.8E-01	AP-42 Table 3.1 & 3-4 of BID	1, 2
Acrolein	107-02-8	6.4E-06	6.528E-03	43%	3.6E-06	3.7E-03	AP-42 Table 3.1 & 3-4 of BID	1
Benzene	71-43-2	1.2E-05	1.224E-02	73%	3.3E-06	3.3E-03	AP-42 Table 3.1 & 3-4 of BID	1
Ethylbenzene	100-41-4	3.2E-05	3.264E-02	50%	1.6E-05	1.6E-02	AP-42 Table 3.1	2
Formaldehyde	50-00-0	7.1E-04	7.242E-01	67%	2.3E-04	2.4E-01	KU Requirement	3
Naphthalene	91-20-3	1.3E-06	1.326E-03	50%	6.5E-07	6.6E-04	AP-42 Table 3.1	2
PAH		2.2E-06	2.244E-03	50%	1.1E-06	1.1E-03	AP-42 Table 3.1	2
Propylene Oxide	75-56-9	2.9E-05	2.958E-02	50%	1.5E-05	1.5E-02	AP-42 Table 3.1	2
Toluene	108-88-3	1.3E-04	1.326E-01	50%	6.5E-05	6.6E-02	AP-42 Table 3.1	2
Xylenes	1330-20-7	6.4E-05	6.528E-02	50%	3.2E-05	3.3E-02	AP-42 Table 3.1	2

1. Controlled emission factors (Oxidation Catalyst) for Acetaldehyde, Acrolein and Benzene are obtained from U.S. EPA's Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines.
2. Emission factors for 1,3- Butadiene, Acetaldehyde, Ethylbenzene, Propylene Oxide, Toluene, Xylenes, Naphthalene and PAH are obtained from AP-42 Chapter 3.1, Table 3.1-3 (Stationary Gas Turbines, April, 2000). A control efficiency of 50% was applied to these uncontrolled/controlled emission factors based on expected VOM control efficiency from catalytic oxidation.
3. See KU requirement above for formaldehyde that sets the GT post-oxidation catalyst EF.
4. The control efficiencies are estimates and should not be construed as guarantees.

4.3.4 Hazardous Air Pollutants for DB

> Emission factors from DBs are obtained from AP-42, Chapter 1.4, Table 1.4-2, 1.4-3, 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Polycyclic aromatic hydrocarbons were omitted from the DB emission factor list since they are accounted for with the GT.

Pollutant	CAS No.	DB Uncontrolled EF (lb/MMBtu)	DB Uncontrolled EF (lb/MMscf)	Oxidation Catalyst CE[5] (%)	DB After Oxidation Catalyst EF (lb/MMBtu)	DB After Oxidation Catalyst EF (lb/MMscf)	Basis	Note
Benzene	71-43-2	2.1E-06	2.1E-03	50%	1.0E-06	1.1E-03	AP-42 Table 1.4-3	1, 2, 4
Dichlorobenzene	25321-22-6	1.2E-06	1.2E-03	50%	5.9E-07	6.0E-04	AP-42 Table 1.4-3	1, 2
Formaldehyde	50-00-0							3
Naphthalene	91-20-3	6.0E-07	6.1E-04	50%	3.0E-07	3.1E-04	AP-42 Table 1.4-3	1, 2, 4
Hexane	110-54-3	1.8E-03	1.8E+00	50%	8.8E-04	9.0E-01	AP-42 Table 1.4-3	1, 2
Toluene	108-88-3	3.3E-06	3.4E-03	50%	1.7E-06	1.7E-03	AP-42 Table 1.4-3	1, 2, 4
Arsenic	7440-38-2	2.0E-07	2.0E-04		2.0E-07	2.0E-04	AP-42 Table 1.4-4	1
Beryllium	7440-41-7	1.2E-08	1.2E-05		1.2E-08	1.2E-05	AP-42 Table 1.4-4	1
Cadmium	7440-43-9	1.1E-06	1.1E-03		1.1E-06	1.1E-03	AP-42 Table 1.4-4	1
Chromium	7440-47-3	1.4E-06	1.4E-03		1.4E-06	1.4E-03	AP-42 Table 1.4-4	1
Cobalt	7440-48-4	8.2E-08	8.4E-05		8.2E-08	8.4E-05	AP-42 Table 1.4-4	1
Lead	7439-92-1	4.9E-07	5.0E-04		4.9E-07	5.0E-04	AP-42 Table 1.4-4	1
Manganese	7439-96-5	3.7E-07	3.8E-04		3.7E-07	3.8E-04	AP-42 Table 1.4-4	1
Mercury	7439-97-6	2.5E-07	2.6E-04		2.5E-07	2.6E-04	AP-42 Table 1.4-4	1
Nickel	7440-02-0	2.1E-06	2.1E-03		2.1E-06	2.1E-03	AP-42 Table 1.4-4	1
Selenium	7782-49-2	2.4E-08	2.4E-05		2.4E-08	2.4E-05	AP-42 Table 1.4-4	1

1. Emission factors are obtained from AP-42, Chapter 1.4, Table 1.4-2, 1.4-3, 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998).
2. A control efficiency of 50% was applied to these uncontrolled emission factors based on expected VOM control efficiency from catalytic oxidation.
3. See KU requirement for formaldehyde produced in the GT, as it applies to the entire NGCC.
4. Not used in PTE analysis because GT EF is higher than DB.
5. The control efficiencies are estimates and should not be construed as guarantees.

4.3.5 Hazardous Air Pollutants for GT + DB

> The following derives the combined HAP emission factors when a GT uses duct burners.

Pollutant	CAS No.	Weighted Average Uncontrolled EF (lb/MMscf)	Control Efficiency[4] (%)	Weighted Average Controlled EF (lb/MMscf)	Note	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
1,3-Butadiene	106-99-0	3.97E-04	50%	1.98E-04	1	0.0017	0.0075	0.0009	0.0037
Acetaldehyde	75-07-0	3.25E-01	50%	1.62E-01	1	1.3957	6.1131	0.6978	3.0565
Acrolein	107-02-8	5.91E-03	43%	3.34E-03	1	0.0254	0.1111	0.0144	0.0629
Benzene	71-43-2	1.13E-02	72%	3.11E-03	2	0.0484	0.2122	0.0134	0.0585
Dichlorobenzene	25321-22-6	1.14E-04	50%	5.72E-05	3	0.0005	0.0022	0.0002	0.0011
Ethylbenzene	100-41-4	2.95E-02	50%	1.48E-02	1	0.1269	0.5557	0.0634	0.2779
Formaldehyde	50-00-0	6.55E-01	67%	2.13E-01	1	2.8152	12.3304	0.9159	4.0116
Naphthalene	91-20-3	1.26E-03	50%	6.29E-04	2	0.0054	0.0237	0.0027	0.0118
Hexane	110-54-3	1.72E-01	50%	8.58E-02	3	0.7374	3.2296	0.3687	1.6148
PAH		2.03E-03	50%	1.02E-03	1	0.0087	0.0382	0.0044	0.0191
Propylene Oxide	75-56-9	2.68E-02	50%	1.34E-02	1	0.1150	0.5036	0.0575	0.2518
Toluene	108-88-3	1.20E-01	50%	6.01E-02	2	0.5168	2.2638	0.2584	1.1319
Xylenes	1330-20-7	5.91E-02	50%	2.95E-02	1	0.2538	1.1115	0.1269	0.5557
Arsenic	7440-38-2	1.91E-05		1.91E-05	3	8.2E-05	3.6E-04	8.2E-05	3.6E-04
Beryllium	7440-41-7	1.14E-06		1.14E-06	3	4.9E-06	2.2E-05	4.9E-06	2.2E-05
Cadmium	7440-43-9	1.05E-04		1.05E-04	3	0.0005	0.0020	0.0005	0.0020
Chromium	7440-47-3	1.33E-04		1.33E-04	3	0.0006	0.0025	0.0006	0.0025
Cobalt	7440-48-4	8.01E-06		8.01E-06	3	3.4E-05	1.5E-04	3.4E-05	1.5E-04
Lead	7439-92-1	4.77E-05		4.77E-05	3	2.0E-04	9.0E-04	2.0E-04	9.0E-04
Manganese	7439-96-5	3.62E-05		3.62E-05	3	1.6E-04	6.8E-04	1.6E-04	6.8E-04
Mercury	7439-97-6	2.48E-05		2.48E-05	3	1.1E-04	4.7E-04	1.1E-04	4.7E-04
Nickel	7440-02-0	2.00E-04		2.00E-04	3	0.0009	0.0038	0.0009	0.0038
Selenium	7782-49-2	2.29E-06		2.29E-06	3	9.8E-06	4.3E-05	9.8E-06	4.3E-05
Total HAP	7782-49-2	1.409	58%	0.588		6.053	26.513	2.527	11.068

1 For a HAP from the GT only, the HAP EF was scaled by the portion of heat input to GT divided by total from both. For instance, 1,3-Butadiene is calculated as:
4.0E-04 lb/MMscf = (4.39E-04 lb/MMscf * (4.297 MMscf/hr - 0.410 MMscf/hr) / 4.297 MMscf/hr

2 For a HAP from both the GT and DB, each HAP EF was scaled by their portion of heat input divided by total from both. For instance, benzene is calculated as:
1.13E-02 lb/MMscf = (1.22E-02 lb/MMscf * (4.297 MMscf/hr - 0.410 MMscf/hr) / 4.297 MMscf/hr +
(2.10E-03 lb/MMscf * (0.410 MMscf/hr) / 4.297 MMscf/hr

3 For a HAP from the DB only, the HAP EF was scaled by the portion of heat input to DB divided by total from both. For instance, hexane is calculated as:
1.628 lb/MMscf = (1.800 lb/MMscf * (0.410 MMscf/hr) / 4.297 MMscf/hr

4 Calculated

4.4 Derivation and Documentation of Steady-State Operation Emission Factors for Natural Gas Firing in GT (58-2)

4.4.1 NSR-Regulated Pollutants

> Controlled EFs for all NSR-regulated pollutants have been calculated for the worst-case annual operating profile while the GT is operating w/o the DBs as provided by the vendor. Any deviations from the vendor estimates are noted below. Lead emissions are discussed in the HAP subsection below.

NO_x

Concentration in stack exhaust after SCR	**2.0**	ppmvd @ 15% O2	KU's vendor guarantee requirement for unfired GT
Controlled Emission Factor	8.436	lb/MMscf	= 31.8 lb/hr / 3.77 MMscf/hr
Controlled Emission Rate	**31.80**	lb/hr	Max lb/hr from vendor specs for unfired NG firing (GE Case EC-3)
Control Efficiency (**not guaranteed**)	90	%	Nominal value for a SCR selected for purposes of defining an uncontrolled emission factor. Estimated efficiency of 94% from provided unit specifications.
Uncontrolled Emission Factor	84.364	lb/MMscf	= 8.436 lb/MMscf / (100% - 90%)

CO

Concentration in stack exhaust after oxidation catalyst	**2.0**	ppmvd @ 15% O2	KU's vendor guarantee requirement for unfired GT
Controlled Emission Factor	5.136	lb/MMscf	= 19.36 lb/hr / 3.77 MMscf/hr
Controlled Emission Rate	**19.363**	lb/hr	Max lb/hr from vendor specs for unfired NG firing (GE Case EC-3)
Control Efficiency (**not guaranteed**)	90	%	Nominal value for a oxidation catalyst
Uncontrolled Emission Factor	51.364	lb/MMscf	= 5.136 lb/MMscf / (100% - 90%)

VOC

Concentration in Stack Exhaust (as methane)	1.0	ppmvd @ 15% O2	KU's vendor guarantee requirement for unfired GT
Controlled Emission Factor	1.471	lb/MMscf	= 5.55 lb/hr / 3.77 MMscf/hr
Controlled Emission Rate	**5.55**	lb/hr	Max lb/hr from vendor specs for unfired NG firing (GE Case EC-3)
Control Efficiency (**not guaranteed**)	50	%	Based on expected VOM control efficiency from catalytic oxidation.
Uncontrolled Emission Factor	2.942	lb/MMscf	= 1.471 lb/MMscf / (100% - 50%)

SO_2

> Vendor was told that the pipeline tariff is based on a sulfur content on 0.5 gr/100 scf (Cscf), and the highest sulfur measured in the last 5 years was 0.116 gr/Cscf. The following estimate is based solely on a maximum sulfur input of 0.5 gr/Cscf and 100% conversion from S to SO_2. In reality, the SO_2 should be reduced by the amount of SO_2 converted to SO_3, which can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. For simplicity, the following methodology does not account for these further reductions and thus the emission estimates are conservative.

Max sulfur content for pipeline gas	**0.5**	gr/Cscf	
Molecular Weight of S	32.07	lb/lbmol	
Molecular Weight of SO2	64.07	lb/lbmol	
Uncontrolled Emission Rate	5.38	lb/hr	= 0.5 lb/Cscf x 10,000 Cscf/MMscf / 7,000 gr/lb / 1,053 x 3,969 MMBtu/hr x 32.07 lb /lbmol SO2 / 64.07 lb/lbmol S x 1 lbmol SO2/1 lbmol S x 100%
Uncontrolled Emission Factor	1.427	lb/MMscf	= 5.38 lb/hr / 3.770 MMscf/hr
Uncontrolled Emission Factor	0.0014	lb/MMBtu	= 5.38 lb/hr / 3,969 2.54901960784314E-07

H_2SO_4

> Within the combustion process, SO_2 can be further oxidized into SO_3, which then can be converted further to H_2SO_4, $(NH_4)_2SO_4$, and/or $(NH_4)HSO_4$. This conversion is influenced by the sulfur content in the fuel, ambient temperature/relative humidity, evaporative cooling operation, duct burner operation, oxidation over the oxidation catalyst, oxidation within the SCR, available moisture, ammonia slip concentration, acid dew point, etc. The estimates below are based on data provided by the equipment vendor.

Molecular Weight of H2SO4	98.08	lb/lbmol	
Uncontrolled Emission Rate	**4.75**	lb/hr	Max lb/hr from vendor specs for unfired NG firing (GE Case EC-3)
Uncontrolled Emission Factor	1.261	lb/MMscf	= 4.75 lb/hr / 3.770 MMscf/hr
Uncontrolled Emission Factor	0.0012	lb/MMBtu	= 4.75 lb/hr / 3,969 MMBtu/hr

$PM/PM_{10}/PM_{2.5}$

> Steady-state generation of PM should be negligible from this NGCC system. When KU asked GE to provide PM estimates, GE provided overly conservative estimates of PM (not guarantees). Given the presence of the oxidation catalyst system, formation of condensable PM (CPM) and sub-micron filterable PM is a possibility under certain conditions. One pathway is the sulfate formation from H2SO4, (NH4)2SO4, and/or (NH4)HSO4, as well as the nitrate formation in the form of NH4NO3. However, the PM emissions from these pathways are still expected to be low. Regardless, given uncertainties, KU conservatively used the information provided by GE for defining PM emissions. In all cases, all PM can be assumed to be less than 2.5 µm in mean diameter (i.e., PM = PM10 = PM2.5).

Uncontrolled Emission Rate	**17.95**	lb/hr	Max lb/hr from vendor specs for unfired NG firing (GE Case EC-3)
Uncontrolled Emission Factor	4.763	lb/MMscf	= 17.95 lb/hr / 3.77 MMscf/hr
Uncontrolled Emission Factor	0.0045	lb/MMBtu	= 4.763 lb/MMscf / 1,053 Btu/scf

Greenhouse Gases

> Emission factors are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Table C-1).
> The global warming multiplying factors for CH4 and N2O are those specified in 40 CFR 98 Subpart A. These are used to calculate the overall CO2e emissions.

CO_2

Uncontrolled Emission Factor	116.98	lb/MMBtu	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	120,019	lb/MMscf	= 116.98 lb/MMBtu * 1,026 MMBtu/MMscf
Uncontrolled Emission Rate	452,430	lb/hr	= 120,019 lb/MMscf x 3.770 MMscf/hr

CH_4

Uncontrolled Emission Factor	0.02	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 1.1×10^{-2} kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	24.881	lb/MMscf	= 0.0243 lb/MMBtu * 1,026 MMBtu/MMscf
Uncontrolled Emission Rate	93.79	lb/hr	= 24.881 lb/MMscf x 3.770 MMscf/hr

N_2O

Uncontrolled Emission Factor	0.00	lb/MMBtu	40 CFR 98, Subpart C, Table C-2; converted from 1.6×10^{-3} kg/MMBtu to lb/MMBtu
Uncontrolled Emission Factor	3.619	lb/MMscf	= 0.0035 lb/MMBtu * 1,026 MMBtu/MMscf
Uncontrolled Emission Rate	13.64	lb/hr	= 3.619 lb/MMscf x 3.770 MMscf/hr

CO_2e

Global Warming Potentials of GHGs per amendment to 40 CFR 98, Subpart A (89 FR 31894, published April 25, 2024)

CO2	1	
CH4	28	89 FR 42218, May 14, 2024
N2O	265	89 FR 42218, May 14, 2024

Uncontrolled Emission Factor	121,674 lb/MMscf	(CO2 EF) + (CH4 EF x CH4 GWP) + (N2O EF x N2O GWP)
Uncontrolled Emission Rate	458,671 lb/hr	= 121,674 lb/MMscf x 3.770 MMscf/hr

4.4.2 Ammonia (from Ammonia Slip in SCR)

NH_3

Concentration in stack exhaust	5.0 ppmvd @ 15% O2	KU's vendor requirement for unfired NGCC
Uncontrolled Emission Factor	7.808 lb/MMscf	= 29.43 lb/hr / 3.77 MMscf/hr
Uncontrolled Emission Rate	29.4 lb/hr	Max lb/hr from vendor specs for unfired NG firing (GE Case EC-3)

4.4.3 Hazardous Air Pollutants for GT

Formaldehyde

Concentration in stack exhaust	0.091 ppmvd @ 15% O2	KU's vendor requirement per 40 CFR §63.6100 and Table 1 of NESHAP YYYY
Molecular weight of HCHO	30.031 lb/lbmol	
Oxygen based F-Factor	8,638 dscf/MMBtu	RM Method 19 determination of Fd factor for natural gas combustion can use a default value of 8,710, or use equations 19-13 through 19.15. KU chose to use GE's derived Fd at ~8,638 dscf/MMBtu.
Controlled Emission Rate	0.95 lb/hr	= 1.0 atm STD x 30.031 lb/lbmol HCHO / 0.7302 ft3-atm/lbmol-°R / 527.67°R STD x 0.091 ppmvd @ 15% O2 /1E6 x 8,638.0 dscf/MMBtu x (20.9/(20.9-15) x 3,969 MMBtu/hr x 1.097 safety factor
Controlled Emission Factor	0.251 lb/MMscf	= 0.95 lb/hr / 3.770 MMscf/hr

> Other than for formaldehyde (described above), emission factors for organic and metallic HAP emissions from natural gas-fired turbines published in AP-42, Section 3.1 are used to estimate potential emissions

Pollutant	CAS No.	GT Uncontrolled EF (lb/MMBtu)	GT Uncontrolled EF (lb/MMscf)	Oxidation Catalyst Control Efficiency[4] (%)	GT After Oxidation Catalyst EF (lb/MMBtu)	GT After Oxidation Catalyst EF (lb/MMscf)	Basis	Note
1,3-Butadiene	106-99-0	4.3E-07	4.386E-04	50.0%	2.2E-07	2.2E-04	AP-42 Table 3.1	2
Acetaldehyde	75-07-0	3.5E-04	3.590E-01	50.0%	1.8E-04	1.8E-01	AP-42 Table 3.1 & 3-4 of BID	1, 2
Acrolein	107-02-8	6.4E-06	6.528E-03	43.4%	3.6E-06	3.7E-03	AP-42 Table 3.1 & 3-4 of BID	1
Benzene	71-43-2	1.2E-05	1.224E-02	72.8%	3.3E-06	3.3E-03	AP-42 Table 3.1 & 3-4 of BID	1
Ethylbenzene	100-41-4	3.2E-05	3.264E-02	50.0%	1.6E-05	1.6E-02	AP-42 Table 3.1	2
Formaldehyde	50-00-0	7.1E-04	7.242E-01	65.4%	2.5E-04	2.5E-01	KU Requirement	3
Naphthalene	91-20-3	1.3E-06	1.326E-03	50.0%	6.5E-07	6.6E-04	AP-42 Table 3.1	2
PAH		2.2E-06	2.244E-03	50.0%	1.1E-06	1.1E-03	AP-42 Table 3.1	2
Propylene Oxide	75-56-9	2.9E-05	2.958E-02	50.0%	1.5E-05	1.5E-02	AP-42 Table 3.1	2
Toluene	108-88-3	1.3E-04	1.326E-01	50.0%	6.5E-05	6.6E-02	AP-42 Table 3.1	2
Xylenes	1330-20-7	6.4E-05	6.528E-02	50.0%	3.2E-05	3.3E-02	AP-42 Table 3.1	2

1. Controlled emission factors (Oxidation Catalyst) for Acetaldehyde, Acrolein and Benzene are obtained from U.S. EPA's Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines.
2. Emission factors for 1,3- Butadiene, Acetaldehyde, Ethylbenzene, Propylene Oxide, Toluene, Xylenes, Naphthalene and PAH are obtained from AP-42 Chapter 3.1, Table 3.1-3 (Stationary Gas Turbines, April, 2000). A control efficiency of 50% was applied to these uncontrolled/controlled emission factors based on expected VOM control efficiency from catalytic oxidation.
3. See KU requirement above for formaldehyde that sets the GT post-oxidation catalyst EF.
4. The control efficiencies are estimates and should not be construed as guarantees.

4.5 NGCC Potential Emissions Summary - Steady State Without DBs

> The following represents the potential emissions assuming the GT+DB combust natural gas at 3,969 MMBtu/hr heat input for 8,760 hours per year, which is not possible given the range of shutdowns and startups that can occur during a particular year. However, to be conservative and to avoid any restriction on the hours of "normal" or steady state operations, this approach is used.

Process ID 2: Steady-State Operation GT without DB

	Uncontrolled EF		Uncontrolled Emissions		~Control	Controlled Emissions	
	(lb/MMscf)	Basis	(lb/hr)	(tpy)	Efficiency	(lb/hr)	(tpy)
Regulated Pollutants							
NOX	84.364	KU Requirement	318.0	1,392.9	90%	31.8	139.3
CO	51.364	KU Requirement	193.6	848.1	90%	19.4	84.8
VOC	2.942	KU Requirement	11.09	48.6	50%	5.55	24.3
PM	4.763	Vendor Estimate	18.0	78.6		18.0	78.6
PM10	4.763	Vendor Estimate	18.0	78.6		18.0	78.6
PM2.5	4.763	Vendor Estimate	18.0	78.6		18.0	78.6
SO2	1.427	Pipeline spec conversion	5.38	23.6		5.38	23.6
H2SO4	1.261	Pipeline spec conversion	4.75	20.8		4.75	20.8
NH3	7.808	KU Requirement	29.43	128.9		29.4	128.9
CO2	120,019	40 CFR 98, Table C-1	452,430	1,981,641		452,430	1,981,641
CH4	0.024	40 CFR 98, Table C-2	0.09	0.4		0.1	0.4
N2O	0.004	40 CFR 98, Table C-2	0.01	0.1		0.0	0.1
CO2e	121,674	40 CFR 98 Subpart A	458,671	2,008,979		458,671	2,008,979

		Uncontrolled EF		Uncontrolled Emissions		~Control	Controlled Emissions	
	CAS No.	(lb/MMscf)	Basis	(lb/hr)	(tpy)	Efficiency	(lb/hr)	(tpy)
Hazardous Air Pollutants								
1,3-Butadiene	106-99-0	4.39E-04	AP-42 Table 3.1	0.0017	0.0072	50.0%	0.0008	0.0036
Acetaldehyde	75-07-0	3.59E-01	AP-42 Table 3.1 & 3-4 of BID	1.3535	5.9281	50.0%	0.6767	2.9641
Acrolein	107-02-8	6.53E-03	AP-42 Table 3.1 & 3-4 of BID	0.0246	0.1078	43.4%	0.0139	0.0610
Benzene	71-43-2	1.22E-02	AP-42 Table 3.1 & 3-4 of BID	0.0461	0.2021	72.8%	0.0125	0.0549
Ethylbenzene	100-41-4	3.26E-02	AP-42 Table 3.1	0.1230	0.5389	50.0%	0.0615	0.2695
Formaldehyde	50-00-0	7.24E-01	KU Requirement	2.7300	11.9573	65.4%	0.9450	4.1393
Naphthalene	91-20-3	1.33E-03	AP-42 Table 3.1	0.0050	0.0219	50.0%	0.0025	0.0109
PAH		2.24E-03	AP-42 Table 3.1	0.0085	0.0371	50.0%	0.0042	0.0185
Propylene Oxide	75-56-9	2.96E-02	AP-42 Table 3.1	0.1115	0.4884	50.0%	0.0558	0.2442
Toluene	108-88-3	1.33E-01	AP-42 Table 3.1	0.4999	2.1894	50.0%	0.2499	1.0947
Xylenes	1330-20-7	6.53E-02	AP-42 Table 3.1	0.2461	1.0778	50.0%	0.1230	0.5389
Total HAP		1.366	Sum	5.150	22.556	58.3%	2.146	9.400

4.6 Capacity and Underlying Assumptions for Cold, Warm, Hot, and Shutdown Events

> The following are estimates provided by the selected vendor:

			Min time in between SD and event	Minimum Event Duration
> Cold starts are preceded by over 72 hours of shutdown.				
Maximum Annual Cold Start Events	10 events/yr	73-280 min/C-SU	72 hr down	1.22 hr
> Warm start cool down duration ranges from >8 to <72 hours after shutdown. Assume 8 hours.				
Maximum Annual Warm Start Events	50 events/yr	63-89 min/W-SU	8 hr down	1.05 hr
> Hot starts are defined as taking place within 0 to 8 hours of the previous shutdown.				
Maximum Annual Hot Start Events	125 events/yr	33-54 min/H-SU	0 hr down	0.55 hr
> Shutdowns will occur for 12-21 min and the total number of events is the sum of all cold, warm, and hot startups.				
Maximum Annual Shutdown Events	185 events/yr	12 min/SD		0.20 hr

4.6.1 Startup and Shutdown Event Emission Factors

> The EFs presented below for emissions of NSR-regulated pollutants from startup and shutdown events are based on vendor-specifications in units of lb/event.

Event Type	NO_X EF (lb/event)	CO EF (lb/event)	VOC EF (lb/event)	$PM/PM_{10}/PM_{2.5}$ EF (lb/event)	SO_2 EF[1] (lb/event)	H_2SO_4 EF[2] (lb/event)	CO_2 EF[3] (lb/event)
Cold Start	420	758	135	32	9.5	8.5	291.390
Warm Start	260	476	121	27	8.0	7.1	249.980
Hot Start	135	303	91	15	4.5	4.0	106.800
Shutdown	78	244	118	5	1.5	1.3	23.571

[1] Calculated as PM (lb/event) times max ratio of SO2/PM of all cases, which was 29.79% for EC-3.
[2] Calculated as PM (lb/event) times max ratio of H2SO4/PM of all cases, which was 26.48% for EC-3.
[3] Calculated using vendor estimate of MMBtu/event times CO2 emission factor of 116.977 lb CO2/MMBtu.

4.7 GT Cold, Warm, & Hot Startups, and Shutdown Potential Emissions Summary

> The following potential emissions represent the maximum pounds per SUSD event by pollutant.

Pollutant	Uncontrolled EF (lb/event)	Basis	Uncontrolled Emissions (lb/yr)	Uncontrolled Emissions (tpy)	Control Efficiency	Controlled Emissions (lb/yr)	Controlled Emissions (tpy)
Process ID 3: Cold Startups							
NOX	420	GE Vendor Data	4,200	2.1	N/A	4,200	2.1
CO	758	GE Vendor Data	7,580	3.79	N/A	7,580	3.79
VOC	135	GE Vendor Data	1,350	0.68	N/A	1,350	0.68
PM	32	GE Vendor Data	320	0.16	N/A	320	0.16
PM10	32	GE Vendor Data	320	0.16	N/A	320	0.16
PM2.5	32	GE Vendor Data	320	0.16	N/A	320	0.16
SO2	9.5	Extrapolated Data	95	0.05	N/A	95	0.05
H2SO4	8.5	Extrapolated Data	85	0.04	N/A	85	0.04
CO2	291,390	Extrapolated Data	2,913,897	1,457	N/A	2,913,897	1,457

Process ID 4: Warm Startups							
NOX	260	GE Vendor Data	13,000	6.5	N/A	13,000	6.50
CO	476	GE Vendor Data	23,800	11.9	N/A	23,800	11.9
VOC	121	GE Vendor Data	6,050	3.03	N/A	6,050	3.03
PM	27.0	GE Vendor Data	1,350	0.68	N/A	1,350	0.68
PM10	27.0	GE Vendor Data	1,350	0.68	N/A	1,350	0.68
PM2.5	27.0	GE Vendor Data	1,350	0.68	N/A	1,350	0.68
SO2	8.0	Extrapolated Data	402	0.20	N/A	402	0.20
H2SO4	7.1	Extrapolated Data	357	0.18	N/A	357	0.18
CO2	249,980	Extrapolated Data	12,498,992	6,249	N/A	12,498,992	6,249
Process ID 5: Hot Startups							
NOX	135	GE Vendor Data	16,875	8.4375	N/A	16,875	8.44
CO	303	GE Vendor Data	37,875	18.9	N/A	37,875	18.9
VOC	91	GE Vendor Data	11,375	5.69	N/A	11,375	5.69
PM	15.0	GE Vendor Data	1,875	0.94	N/A	1,875	0.94
PM10	15.0	GE Vendor Data	1,875	0.94	N/A	1,875	0.94
PM2.5	15.0	GE Vendor Data	1,875	0.94	N/A	1,875	0.94
SO2	4.5	Extrapolated Data	559	0.28	N/A	559	0.28
H2SO4	4.0	Extrapolated Data	497	0.25	N/A	497	0.25
CO2	106,800	Extrapolated Data	13,350,000	6,675	N/A	13,350,000	6,675
Process ID 6: Shutdowns							
NOX	78	GE Vendor Data	14,430	7.215	N/A	14,430	7.22
CO	244	GE Vendor Data	45,140	22.6	N/A	45,140	22.6
VOC	118	GE Vendor Data	21,830	10.9	N/A	21,830	10.92
PM	5.0	GE Vendor Data	925	0.46	N/A	925	0.46
PM10	5.0	GE Vendor Data	925	0.46	N/A	925	0.46
PM2.5	5.0	GE Vendor Data	925	0.46	N/A	925	0.46
SO2	1.5	Extrapolated Data	276	0.14	N/A	276	0.14
H2SO4	1.3	Extrapolated Data	245	0.12	N/A	245	0.12
CO2	23,571	Extrapolated Data	4,360,610	2,180	N/A	4,360,610	2,180
Sum of SU/SD Events							
NOX			48,505	24.2525	N/A	48,505	24.25
CO			114,395	57.2	N/A	114,395	57.2
VOC			40,605	20.3	N/A	40,605	20.30
PM			4,470	2.24	N/A	4,470	2.24
PM10			4,470	2.24	N/A	4,470	2.24
PM2.5			4,470	2.24	N/A	4,470	2.24
SO2			1,332	0.67	N/A	1,332	0.67
H2SO4			1,184	0.59	N/A	1,184	0.59
CO2			33,123,500	16,562	N/A	33,123,500	16,562

4.8 NGCC Overall Combined PTE Summary - Steady State Operations + SUSD Events

> The table below summarizes the PTE from all Process IDs. The worst-case emissions are based on three scenarios.
Scenario 1 includes 8,760 hours at "normal" or steady state operations of GT **and** DB.
Scenario 2 includes 8,760 hours at "normal" or steady state operations of GT only.
Scenario 3 includes 7,528 hours of SS operations, the worst-case emissions from SUSD events, minimum amount of time per event, and downtime between CS and WS events.

Pollutant	PTE (tpy)	PTE Scenario 1 (GT + DB Steady State 8,760 Hours) (tpy)	PTE Scenario 2 (GT Steady State 8,760 Hours) (tpy)	PTE Scenario 3 (Maximum SUSD and Steady State 7,528 hr/yr) (tpy)	Worst-Case Scenario
NOX	151.4	149.1	139.3	**151.4**	Scenario 3
CO	134.6	90.8	84.8	**134.6**	Scenario 3
VOC	64.6	52.0	24.3	**64.6**	Scenario 3
PM	98.9	**98.9**	78.6	86.6	Scenario 1
PM10	98.9	**98.9**	78.6	86.6	Scenario 1
PM2.5	98.9	**98.9**	78.6	86.6	Scenario 1
SO2	26.9	**26.9**	23.6	23.6	Scenario 1
H2SO4	23.7	**23.7**	20.8	20.8	Scenario 1
NH3	138.0	**138.0**	128.9	117.7	Scenario 1
CO2e	2,289,968	**2,289,968**	2,008,979	1,952,638	Scenario 1
1,3-Butadiene	3.73E-03	**3.73E-03**	3.62E-03	3.18E-03	Scenario 1
Acetaldehyde	3.06	**3.06**	2.96	2.61	Scenario 1
Acrolein	6.29E-02	**0.063**	0.061	0.054	Scenario 1
Benzene	5.85E-02	**0.058**	0.055	0.050	Scenario 1
Dichlorobenzene	1.08E-03	**1.08E-03**	N/A	9.18E-04	Scenario 1
Ethylbenzene	0.28	**0.278**	0.269	0.237	Scenario 1
Formaldehyde	4.01	**4.012**	4.139	3.421	Scenario 1
Hexane	1.61	**1.615**	N/A	1.377	Scenario 1
Naphthalene	1.18E-02	**0.012**	0.011	0.010	Scenario 1
PAH	1.91E-02	**0.019**	0.019	0.016	Scenario 1
Propylene Oxide	0.25	**0.252**	0.244	0.215	Scenario 1
Toluene	1.13	**1.132**	1.095	0.965	Scenario 1
Xylenes	0.56	**0.556**	0.539	0.474	Scenario 1
Arsenic	3.59E-04	**3.59E-04**	N/A	3.06E-04	Scenario 1
Beryllium	2.15E-05	**2.15E-05**	N/A	1.84E-05	Scenario 1
Cadmium	1.97E-03	**1.97E-03**	N/A	1.68E-03	Scenario 1
Chromium	2.51E-03	**2.51E-03**	N/A	2.14E-03	Scenario 1
Cobalt	1.51E-04	**1.51E-04**	N/A	1.29E-04	Scenario 1
Lead	8.97E-04	**8.97E-04**	N/A	7.65E-04	Scenario 1
Manganese	6.82E-04	**6.82E-04**	N/A	5.81E-04	Scenario 1
Mercury	4.67E-04	**4.67E-04**	N/A	3.98E-04	Scenario 1
Nickel	3.77E-03	**3.77E-03**	N/A	3.21E-03	Scenario 1
Selenium	4.31E-05	**4.31E-05**	N/A	3.67E-05	Scenario 1
Total HAP	11.07	**11.07**	9.40	9.44	Scenario 1

5. Derivation of Emissions Factors and Calculations for EU 59: Auxiliary Steam Boiler

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 59: Auxiliary Steam Boiler are documented in this section.

Equipment ID (SI): **59**
Emission Unit Description: Auxiliary Steam Boiler
Equipment ID (SI): COMB20

5.1 Process Unit(s)

Process ID: **1**
EU ID - PID: **59-1**
Process Description: **Natural Gas Combustion w/ LNB & FGR**
Control Device ID: N/A
Control Device Description: NA
Stack ID: S-59
Stack Description: Vertically Unobstructed Stack
Applicable Regulation: 401 KAR 51:017, 59:015, 60:005, & 63:002, 40 CFR 60 Subpart Dc, 40 CFR 63 Subpart DDDDD
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 10200602
SCC Description: External Combustion Boilers - Industrial (1-02) - Natural Gas (1-02-006) - 10-100 Million Btu/hr (1-02-006-02)
SCC Units: Million Cubic Feet Natural Gas Burned

5.2 Capacity and Fuel Information for 59-1, Natural Gas Combustion w/ LNB & FGR

> The Aux Boiler is expected to be a Rentech M0500 or similar. The boiler is rated at 75,000 lbs of steam gross with a maximum heat input of 95.52 MMBtu/hr. It will be equipped with LNBs with a flue gas recirculation (FGR) system.
> Although the Aux Boiler will only operate periodically to assist with warm or cold startups of BR12 and to provide freeze protection during winter downtime hours, potential emissions are calculated based on 4,000 hr/yr of operation.

Max Annual Operating Hours	4,000	hr/yr	
Heat Input Capacity	**95.52**	**MMBtu/hr**	
Gross Steam Generation	75,000	lb/hr	
Net Steam Generation	65,000	lb/hr	
NG Heating Value	1,053	Btu/scf	Average for Brown Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0907	MMscf/hr	95.5185 MMBtu/hr / 1,053 MMBtu/MMscf = 0.0907 MMscf/hr
NG HHV used for AP-42 1.4	1,020	Btu/scf	
NG HHV used for Part 98, Subpart C	1,026	Btu/scf	

5.3 Derivation and Documentation of Emission Factors

5.3.1 Constants and Conversion Factors

Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO2	64.07	lb SO_2/lbmol	
Molecular Weight of H2SO4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for Brown inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

5.3.2 Prospective Vendor Data

Pollutant	CAS #	Concentration (ppmv @ 3% O_2)	Concentration (ppmv @ 0% O_2)	Emission Factor Basis
NOx	na	30	35	KU requirement for boiler with LNBs and FGR firing at high fire (100% load); exhaust expressed at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)
CO	00630-08-0	50	58	KU requirement at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)

5.3.3 Regulated NSR Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	0.036	38.34	KU's Vendor requirement 35 lbmol NO2/10^6 lbmol air x 46.01 lb NO2/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,053 MMBtu/MMscf = 38.339 lb/MMscf
CO	00630-08-0	0.037	38.90	KU's Vendor requirement 58 lbmol NO2/10^6 lbmol air x 28.01 lb NO2/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,053 MMBtu/MMscf = 38.900 lb/MMscf
VOC	na	0.0054	5.50	KU's Vendor Engineering Estimate
PM/PM10/PM2.5-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0051	5.2	Calculated as the difference between vendor guarantee and AP-42 filterable value.
PM/PM10/PM2.5 Total		0.0070	7.1	KU's Vendor Engineering Estimate
SO2	07446-09-5	0.0014	1.4	0.5 gr/Ccf / 7,000 gr/lb x 64.07 lb SO2/lbmol / 32.07 lb S/lbmol x 10,000 Ccf/MMscf = 1.427 lb/MMscf
H2SO4	7664-93-9	1.04E-04	1.09E-01	5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 = 1.427 lb SO2/MMscf * 5% * 100% * 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO2		116.98	123,177	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH4		0.0022	2.321	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N2O		0.0002	0.232	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO2e		117.10	123,304	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

5.3.4 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.8E+00
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

5.4 Aux Boiler Potential Emissions Summary

Pollutant		Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_x		38.339	KU Requirement	3.478	6.96
CO		38.900	KU Requirement	3.529	7.06
VOC		5.5	KU Requirement	0.499	1.00
PM	filterable	1.9	AP-42 Table 1.4-2	0.172	0.34
PM10	filterable	1.9	AP-42 Table 1.4-2	0.172	0.34
PM2.5	filterable	1.9	AP-42 Table 1.4-2 + KU Requirement	0.172	0.34
PM/PM10/PM2.5 Total		7.14	KU Requirement	0.648	1.30
SO2		1.43	Pipeline spec conversion	0.129	0.26
H2SO4		0.109	Pipeline spec conversion	0.010	0.02
Lead		0.0005	AP-42, Table 1.4-2	4.54E-05	9.07E-05
CO2		123,177	40 CFR 98, Table C-1	11,173	22,347
CH4		2.3215	40 CFR 98, Table C-2	0.211	0.42
N2O		0.2321	40 CFR 98, Table C-2	0.021	0.04
CO2e		123,304	40 CFR 98, Subpart A	11,185	22,370
Hazardous Air Pollutants					
Benzene		2.1E-03	AP-42, Table 1.4-3	1.90E-04	3.81E-04
Dichlorobenzene		1.2E-03	AP-42, Table 1.4-3	1.09E-04	2.18E-04
Formaldehyde		7.5E-02	AP-42, Table 1.4-3	6.80E-03	1.36E-02
Hexane		1.800	AP-42, Table 1.4-3	0.163	0.327
Naphthalene		6.1E-04	AP-42, Table 1.4-3	5.53E-05	1.11E-04
Toluene		3.4E-03	AP-42, Table 1.4-3	3.08E-04	6.17E-04
Arsenic		2.0E-04	AP-42, Table 1.4-4	1.81E-05	3.63E-05
Cadmium		1.1E-03	AP-42, Table 1.4-4	9.98E-05	2.00E-04
Chromium		1.4E-03	AP-42, Table 1.4-4	1.27E-04	2.54E-04
Manganese		3.8E-04	AP-42, Table 1.4-4	3.45E-05	6.89E-05
Mercury		2.6E-04	AP-42, Table 1.4-4	2.36E-05	4.72E-05
Nickel		2.1E-03	AP-42, Table 1.4-4	1.90E-04	3.81E-04
Total HAP		1.89	Sum	0.171	0.342

Sample Calculations:

NOx (lb/hr) = 38.339 lb/MMscf x 0.0907 MMscf/hr = 3.478 lb/hr NOx

NOx (tpy) = 3.478 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 15.23 tpy NOx

6. Derivation of Emissions Factors and Calculations for EU 60: Fuel Gas (Dewpoint) Preheater

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 60: Fuel Gas (Dewpoint) Preheater are documented in this section.

Equipment ID (SI): **60**
Emission Unit Description: Fuel Gas (Dewpoint) Preheater
Equipment ID (SI): COMB21

6.1 Process Unit(s)

Process ID: 1
EU ID - PID: 60-1
Process Description: NG Fuel Combustion (15.65 MMBtu/hr)
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-60
Stack Description: Vertically Unobstructed Stack
Applicable Regulation: 401 KAR 59:015, 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 39990003
SCC Description: Industrial Processes - Miscellaneous Manufacturing Industries (3-99) - Miscellaneous Manufacturing Industries (3-99-900) - Natural Gas: Process Heaters (3-99-900-03)
SCC Units: Million Cubic Feet Natural Gas Burned

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**15.65**	**MMBtu/hr**	
NG Heating Value	1,053	Btu/scf	Average for Brown Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0149	MMscf/hr	15.65 MMBtu/hr / 1,053 MMBtu/MMscf = 0.0149
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	
NG HHV used for Part 98, Subpart C	1,026	Btu/scf	

6.2 Derivation and Documentation of Emission Factors

6.2.1 Constants and Conversion Factors

Parameter	Value	Units	Basis
Molar Volume (at STP)	385.5	scf/lbmol	= 528 °R / 1 atm x 0.7302 cf-atm/(lbmol-°R)
Atomic Weight of Sulfur	32.07	lb/lbmol	
Molecular Weight of NO2	46.01	lb NO_2/lbmol	
Molecular Weight of CO	28.01	lb CO/lbmol	
Molecular Weight of SO2	64.07	lb SO_2/lbmol	
Molecular Weight of H2SO4	98.079	lb H_2SO_4/lbmol	
F-Factor for natural gas combustion from 40 CFR 60, Appendix A (Method 19)	8,710	dscf/MMBtu	
Concentration of Sulfur in Natural Gas	0.5	gr/Ccf	Assumed max sulfur content for Brown inlet natural gas
Estimated SO_2 to SO_3 Conversion Rate	5.00	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100.00	%	

6.2.2 Prospective Vendor Data

Pollutant	CAS #	Concentration (ppmv @ 3% O_2)	Concentration (ppmv @ 0% O_2)	Emission Factor Basis
NO_X	na	30	35	KU requirement for boiler at high fire (100% load); exhaust expressed at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)
CO	00630-08-0	50	58	KU requirement at 100% load at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)

6.2.3 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	**0.038**	38.34	KU's Vendor requirement 35 lbmol NO2/10^6 lbmol air x 46.01 lb NO2/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,053 MMBtu/MMscf = 38.339
CO	00630-08-0	0.038	38.90	KU's Vendor requirement 58 lbmol CO/10^6 lbmol air x 28.01 lb CO/lbmol / 385.5 scf/lbmol x 8,710 dscf/MMBtu x 1,053 MMBtu/MMscf = 38.900
VOC	na	0.008	8.2	KU's Vendor Engineering Estimate
PM/PM10/PM2.5-Filt		0.0019	1.90	AP-42 Section 1.4 Table 1.4-2 (7/98)
PM-Condensable		0.0015	1.57	AP-42 Table 1.4-2 + EPA Speciate Database, difference between EPA Speciate database for total PM and AP-42 for filterable PM.
PM/PM10/PM2.5 Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database.
PM/PM10/PM2.5 Total		0.0070	7.2	KU's Vendor Engineering Estimate
SO2	07446-09-5	0.0014	1.427	0.5 gr/Ccf / 7,000 gr/lb x 64.07 lb SO2/lbmol / 32.07 lb S/lbmol x 10,000 Ccf/MMscf = 1.427 lb/MMscf
H2SO4	7664-93-9	1.04E-04	1.09E-01	5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4 = 1.427 lb SO2/MMscf * 5% * 100% * 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol
Lead		4.90E-07	0.0005	AP-42, Section 1.4, Table 1.4-2
CO2		116.98	120,019	40 CFR 98, Subpart C, Table C-1; converted from 53.06 kg/MMBtu
CH4		0.0022	2.26	40 CFR 98, Subpart C, Table C-2; converted from 0.001 kg/MMBtu
N2O		0.0002	0.226	40 CFR 98, Subpart C, Table C-2; converted from 0.0001 kg/MMBtu
CO2e		117.10	120,142	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

6.2.4 Hazardous Air Pollutants

> Emission factors for HAPs are obtained from AP-42, Chapter 1.4, Table 1.4-3 and 1.4-4 (Emission Factors for Natural Gas Fired External Combustion Sources, July, 1998). Emissions are only tabulated for pollutants with emission factors greater than or equal to 1.0E-04 lb/MMscf.

Pollutant	Emission Factor (lb/MMscf)
Speciated Organic Compounds (AP-42, Table 1.4-3)	
Benzene	2.1E-03
Dichlorobenzene	1.2E-03
Formaldehyde	7.5E-02
Hexane	1.8E+00
Naphthalene	6.1E-04
Toluene	3.4E-03
Metals (AP-42, Table 1.4-4)	
Arsenic	2.0E-04
Cadmium	1.1E-03
Chromium	1.4E-03
Manganese	3.8E-04
Mercury	2.6E-04
Nickel	2.1E-03
Total HAP	1.888

6.3 Preheater Potential Emissions Summary

Pollutant		Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	(tpy)
NO_x		38.339	KU Requirement	0.570	2.496
CO		38.900	KU Requirement	0.578	2.532
VOC		8.2	AP-42 Table 1.4-2	0.122	0.534
PM	filterable	1.9	AP-42 Table 1.4-2	0.028	0.12
PM10	filterable	1.9	AP-42 Table 1.4-2 + EPA Speciate Database	0.028	0.12
PM2.5	filterable	1.9	AP-42 Table 1.4-2	0.028	0.12
PM/PM10/PM2.5	Total	3.47	AP-42 Table 1.4-2 + EPA Speciate Database.	0.052	0.23
SO2		1.43	Pipeline spec conversion	0.021	0.093
H2SO4		0.109	Pipeline spec conversion	1.62E-03	7.11E-03
Lead		0.0005	AP-42, Table 1.4-2	7.43E-06	3.25E-05
CO2		120,019	40 CFR 98, Table C-1	1,784	7,813
CH4		2.2619	40 CFR 98, Table C-2	0.034	0.147
N2O		0.2262	40 CFR 98, Table C-2	0.003	0.015
CO2e		120,142	40 CFR 98, Subpart A	1,786	7,821
Hazardous Air Pollutants					
Benzene		2.1E-03	AP-42, Table 1.4-3	3.12E-05	1.37E-04
Dichlorobenzene		1.2E-03	AP-42, Table 1.4-3	1.78E-05	7.81E-05
Formaldehyde		7.5E-02	AP-42, Table 1.4-3	1.11E-03	4.88E-03
Hexane		1.8E+00	AP-42, Table 1.4-3	2.68E-02	1.17E-01
Naphthalene		6.1E-04	AP-42, Table 1.4-3	9.07E-06	3.97E-05
Toluene		3.4E-03	AP-42, Table 1.4-3	5.05E-05	2.21E-04
Arsenic		2.0E-04	AP-42, Table 1.4-4	2.97E-06	1.30E-05
Cadmium		1.1E-03	AP-42, Table 1.4-4	1.63E-05	7.16E-05
Chromium		1.4E-03	AP-42, Table 1.4-4	2.08E-05	9.11E-05
Manganese		3.8E-04	AP-42, Table 1.4-4	5.65E-06	2.47E-05
Mercury		2.6E-04	AP-42, Table 1.4-4	3.86E-06	1.69E-05
Nickel		2.1E-03	AP-42, Table 1.4-4	3.12E-05	1.37E-04
Total HAP		1.9E+00	Sum	2.81E-02	1.23E-01

Sample Calculations:

NOx (lb/hr) = 38.339 lb/MMscf x 0.0149 MMscf/hr = 0.570 lb/hr NOx

NOx (tpy) = 0.570 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2.50 tpy NOx

7. Derivation of Emissions Factors and Calculations for EU 61: 2.18 MW Diesel Emergency Generator

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 61: 2.18 MW Diesel Emergency Generator are documented in this section.

Equipment ID (SI): **61**
Emission Unit Description: 2.18 MW Diesel Emergency Generator
Equipment ID (SI): COMB22

7.1 Process Unit(s)

Process ID: 1
EU ID - PID: 61-1
Process Description: Diesel Fuel Combustion
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-61
Stack Description: Vertically Unobstructed Stack
Applicable Regulation: NSPS IIII, RICE MACT, 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20100102
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Reciprocating (2-01-001-02)

SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned

> KU plans to provision a diesel-fired emergency generator for the NGCC project. The generator will be a 2 MW generator set Kohler KD2000 with a maximum engine rating of 2,180 kW. For permitting purposes and to calculate potential emissions, this maximum rating is assumed.

Generator Rating	2,180	**kW**	Maximum power output
Engine Rating	2,923	bhp	Maximum power output
Annual Operating Hours	500	hr/yr	The PTE of emergency generators may be based on 500 operating hours annually per EPA guidance.
Diesel Heating Value:	137.03	MMBtu/Mgal	Assume heating value of 137,030 Btu/gallon for diesel fuel based on AP-42, Table 3.4-1, Footnote 'a', i.e., 19300 Btu/lb * 7.1 lb/gallon = 137,000 Btu/gallon
Diesel Heating Value:	138.00	MMBtu/Mgal	HHV per 40 CFR 98 Subpart C
Maximum Fuel Consumption:	0.149	Mgal/hr	Vendor data
Maximum Heat Input:	20.42	MMBtu/hr	

7.2 Derivation and Documentation of Emission Factors

> The Kohler KD2000 utilizes a KD62V12 engine. Kohler states that this engine is EPA Tier 2 certified for stationary emergency applications. The emission factors for NO_X, VOC, CO, and $PM/PM_{10}/PM_{2.5}$. are based on the NSPS IIII specification for this age and size of engine. Emission factors for NSR-regulated pollutants not included in the manufacturer's emissions data are from AP-42, Section 3.4 Large Stationary Diesel and All Stationary Dual-Fuel Engines (for other criteria pollutants and HAP), and 40 CFR 98, Subpart C, Table C-2 (for non-CO_2 greenhouse gases).

NO_X

Emission factor for NO_X + NMHC:	6.4	g/kW-hr	Tier 2 Emission Standards per NSPS IIII
	4.8	g/hp-hr	Converted

> A separate VOC and NO_X emission factor that conforms to the Subpart IIII requirements can be derived based on the ratio of the TOC to NO_X factor in AP-42 Table 3.4-1 (10/1996 edition).

Sum of AP-42 NO_X and TOC emission factors:	0.025	lb/hp-hr	AP-42 Table 3.4-1 for Diesel Fuel
Ratio of NO_X factor to sum of NO_X and TOC factors:	0.974		= 0.024 / 0.025 lb/hp-hr
Ratio of TOC factor to sum of NO_X and TOC factors:	0.026		= 0.91 * 7.05 E-04 / 0.025
Emission factor for NO_X:	4.65	g/hp-hr	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW
NO_X emission factor in terms of SCC units:	201.1	lb/Mgal	= 4.65 g/hp-hr x 2,923 bhp / 0.149 Mgal/hr / 453.593 gm/lb

VOC

Emission factor for VOC:	0.12	g/hp-hr	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW
VOC emission factor in terms of SCC units:	5.375	lb/Mgal	= 0.12 g/hp-hr x 2,923 bhp / 0.149 Mgal/hr / 453.593 gm/lb

CO

Emission factor for CO:	2.6	g/hp-hr	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I
CO emission factor in terms of SCC units:	111.350	lb/Mgal	= 2.57 g/hp-hr x 2,923 bhp / 0.149 Mgal/hr / 453.593 gm/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.15	g/hp-hr	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	6.363	lb/Mgal	= 0.15 g/hp-hr x 2,923 bhp / 0.149 Mgal/hr / 453.593 gm/lb

SO_2

> To take into account the lower sulfur content of the diesel fuel burned, and for purposes of representing SO_2 emissions from the engine, the factor in AP-42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO_2 as a function of sulfur content. As required under NSPS Subpart IIII, ultra low sulfur diesel (ULSD) must be used in the new emergency generator engine.

AP-42 Factor for SO_2 based on sulfur content:	1.01 S	lb/MMBtu	AP-42 Table 3.4-1 (S is sulfur content in %)
Sulfur Content:	0.0015	%	Based on maximum sulfur content in ULSD of 15 ppm
SO_2 emission factor (lb/MMBtu):	1.52E-03	lb/MMBtu	= 1.01 EF x 0.0015%, sulfur
SO_2 emission factor in terms of SCC units:	0.208	lb/Mgal	= 1.52E-03 lb/MMBtu x 137 MMBtu/Mgal

Greenhouse Gases

> CO_2, CH_4 and N_2O emissions for diesel fuel combustion are estimated using the Distillate Fuel Oil No. 2 emission factors published in 40 CFR 98, Subpart C, Table C-1 & 2. CO_2e emissions for diesel fuel combustion are estimated using the global warming potentials published in 40 CFR 98, Subpart A. Table A-1.

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO_2	1
CH_4	28
N_2O	265

Pollutant	Emission Factor (kg/MMBtu)	Equivalent Factor (lb/Mgal)	
CO_2	73.96	22,501	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2
CH_4	3.00E-03	0.913	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
N_2O	6.00E-04	0.183	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
CO_2e	74.20	22,575	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

7.2.1 Hazardous Air Pollutants

> Emission factors for organic HAP compounds expected to be emitted are based on emission factors in AP-42 Table 3.4-3 and 3.4-4 (10/96 Edition). Emission factors are converted from lb/MMBtu as provided in AP-42 to lb/Mgal as applicable to the SCC designation.

Pollutant	CAS #	HAP?	Emission Factor (lb/MMBtu)	Emission Factor (lb/Mgal)
Acetaldehyde	75-07-0	Y	2.52E-05	3.45E-03
Acrolein	107-02-8	Y	7.88E-06	1.08E-03
Benzene	71-43-2	Y	7.76E-04	1.06E-01
Formaldehyde	50-00-0	Y	7.89E-05	1.08E-02
Naphthalene	91-20-3	Y	1.30E-04	1.78E-02
PAH		Y	2.12E-04	2.91E-02
Toluene	108-88-3	Y	2.81E-04	3.85E-02
Xylenes	1330-20-7	Y	1.93E-04	2.64E-02

7.3 Emergency Generator Potential Emissions Summary

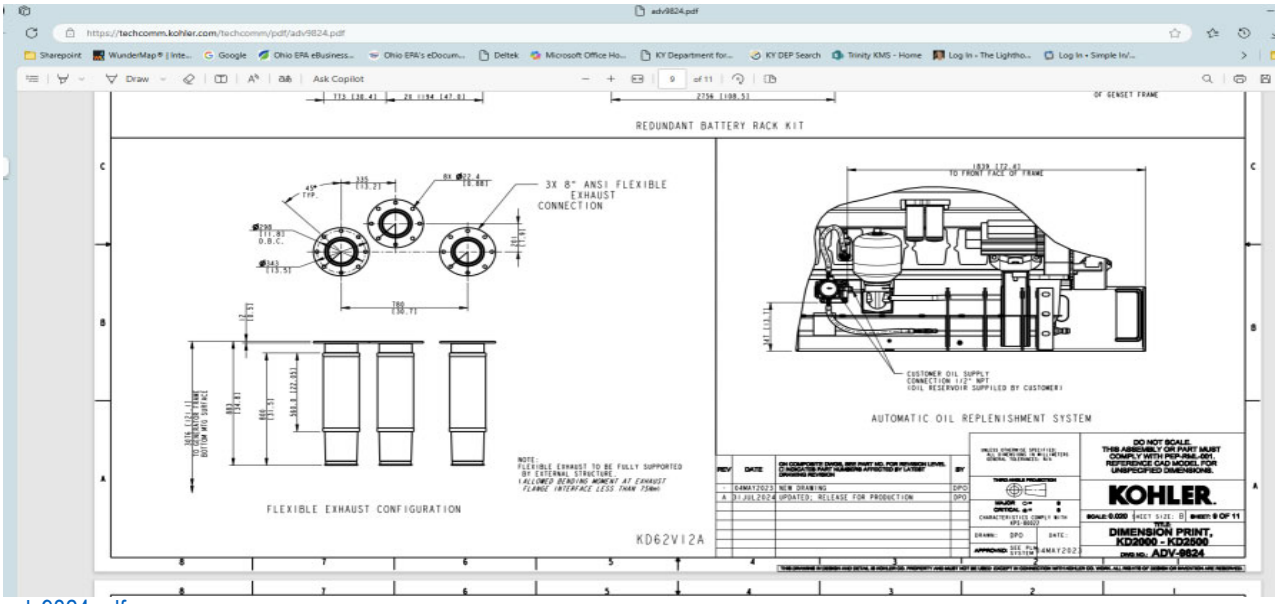
Pollutant	Emission Factor (lb/Mgal)	Basis	Potential Emissions (lb/hr)	(tpy)
NOx	201.137	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW	29.969	7.49
CO	111.350	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I	16.591	4.15
VOC	5.375	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW	0.801	0.200
PM	6.363	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I	0.948	0.237
PM10	6.363	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I	0.948	0.237
PM2.5	6.363	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I	0.948	0.237
SO2	0.208	AP-42 Table 3.4-1	0.031	0.008
CO2	22,501	40 CFR 98, Subpart C, Table C-1	3,353	838.18
CH4	0.913	40 CFR 98, Subpart C, Table C-2	0.136	0.034
N2O	0.183	40 CFR 98, Subpart C, Table C-2	0.027	0.007
CO2e	22,575	40 CFR 98, Subpart A	3,364	840.93
Hazardous Air Pollutants				
Acetaldehyde	0.0035	AP-42 Table 3.4-3	5.15E-04	1.29E-04
Acrolein	0.0011	AP-42 Table 3.4-3	1.61E-04	4.02E-05
Benzene	0.106	AP-42 Table 3.4-3	1.58E-02	3.96E-03
Formaldehyde	0.011	AP-42 Table 3.4-3	1.61E-03	4.03E-04
Naphthalene	0.018	AP-42 Table 3.4-4	2.65E-03	6.64E-04
PAH	0.029	AP-42 Table 3.4-4	4.33E-03	1.08E-03
Toluene	0.039	AP-42 Table 3.4-3	5.74E-03	1.43E-03
Xylenes	0.026	AP-42 Table 3.4-3	3.94E-03	9.85E-04
Total HAP	0.233	AP-42 Table 3.4-3	3.48E-02	8.70E-03

Sample Calculations:
NOx (lb/hr) = 201.137 lb/Mgal x 0.149 Mgal/hr = 29.969 lb/hr NOx
NOx (tpy) = 29.969 lb/hr x 500 hr/yr / 2,000 lb/ton = 7.49 tpy NOx

Example Spec Sheet



https://www.powersystems.rehlko.com/product/kd2000


REDUNDANT BATTERY RACK KIT
3X 8" ANSI FLEXIBLE EXHAUST CONNECTION
FLEXIBLE EXHAUST CONFIGURATION
AUTOMATIC OIL REPLENISHMENT SYSTEM
KD62V12A
KOHLER.
DIMENSION PRINT, KD2000 - KD2500
ADV-9824

adv9824.pdf

8. Derivation of Emissions Factors and Calculations for EU 62: 422 HP Diesel Driven Fire Pump

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 62: 422 HP Diesel Driven Fire Pump are documented in this section.

Equipment ID (SI): **62**
Emission Unit Description: 422 HP Diesel Driven Fire Pump
Equipment ID (SI): COMB23

8.1 Process Unit(s)

Process ID: **1**
EU ID - PID: **62-1**
Process Description: **Diesel Fuel Combustion**
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-62
Stack Description: Vertically Unobstructed Stack
Applicable Regulation: NSPS IIII, RICE MACT, 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20100102
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Distillate Oil (Diesel) (2-01-001) - Reciprocating (2-01-001-02)
SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned

> KU plans to provision a diesel-fired emergency fire pump engine for the NGCC project. The fire pump will be a Clarke JW6H-UFAD80, 422 bph diesel-fired pump. For permitting purposes and to calculate potential emissions, this maximum rating is assumed.

Engine Rating	**422**	**bhp**	
Annual Operating Hours	500	hr/yr	The PTE of emergency engines may be based on 500 operating hours annually per EPA guidance.
Diesel Heating Value:	137.03	MMBtu/Mgal	Assume heating value of 137,030 Btu/gallon for diesel fuel based on AP-42, Table 3.4-1, Footnote 'a', i.e., 19300 Btu/lb * 7.1 lb/gallon = 137,000 Btu/gallon
Avg Brake-Specific Fuel Consumption:	7,000	Btu/hp-hr	AP-42, Chapter 3.3 Gasoline and Diesel Industrial Engines, Table 3.3-1 Footnote a
Maximum Fuel Consumption:	0.022	Mgal/hr	= 422 bhp x 7,000 Btu/hp-hr / 1E6 Btu/MMBtu / 137.03 MMBtu/Mgal
Maximum Heat Input:	2.95	MMBtu/hr	

8.2 Derivation and Documentation of Emission Factors

> Clarke JW6H-UFAD80 meets EPA Tier III emissions standards. Emissions factors for Clarke JW6H-UFAD80 for NOX, VOC, CO, and PM/PM10/PM2.5 from vendor datasheet. Emission factors for NSR-regulated pollutants not included in the manufacturer's emissions data are from AP-42, Section 3.3 Gasoline and Diesel Industrial Engines (for other criteria pollutants and HAP), and 40 CFR 98, Subpart C, Table C-2 (for non-CO2 greenhouse gases).

Emission factor for NO_X + NMHC:	4.0	g/kW-hr	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
	3.0	g/hp-hr	Converted

> A separate VOC and NO_X emission factor that conforms to the Subpart IIII requirements can be derived based on the ratio of the TOC to NO_X factor in AP-42 Table 3.3-1 (10/1996 edition).

Sum of AP-42 NO_X and TOC emission factors:	0.034	lb/hp-hr	AP-42 Table 3.3-1 for Diesel Fuel
Ratio of NO_X factor to sum of NO_X and TOC factors:	0.925		= 0.031 / 0.034 lb/hp-hr
Ratio of TOC factor to sum of NO_X and TOC factors:	0.075		= 0.00247 + 4.41 E-05 / 0.034

NO_X

Emission factor for NO_X: as BACT	3.7	g/hp-hr	= 4 g/kW-hr * 0.925 / 1.341 hp/kW
NO_X emission factor in terms of SCC units:	159.7	lb/Mgal	= 3.70 g/hp-hr x 422 bhp / 0.022 Mgal/hr / 453.593 gm/lb

VOC

Emission factor for VOC:	0.22	g/hp-hr	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW
VOC emission factor in terms of SCC units:	9.66	lb/Mgal	= 0.22 g/hp-hr x 422 bhp / 0.022 Mgal/hr / 453.593 gm/lb

CO

Emission factor for CO:	2.60	g/hp-hr	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
CO emission factor in terms of SCC units:	112.21	lb/Mgal	= 2.60 g/hp-hr x 422 bhp / 0.022 Mgal/hr / 453.593 gm/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.15	g/hp-hr	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	6.47	lb/Mgal	= 0.15 g/hp-hr x 422 bhp / 0.022 Mgal/hr / 453.593 gm/lb

SO_2

> To take into account the lower sulfur content of the diesel fuel burned, and for purposes of representing SO_2 emissions from the engine, the factor in AP-42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO_2 as a function of sulfur content. As required under NSPS Subpart IIII, the ultra low sulfur diesel (ULSD) must be used in the new emergency generator engine.

AP-42 Factor for SO_2 based on sulfur content:	1.01 S	lb/MMBtu	AP-42 Table 3.4-1 (S is sulfur content in %)
Sulfur Content:	0.0015	%	Based on maximum sulfur content in ULSD of 15 ppm
SO_2 emission factor (lb/MMBtu):	1.52E-03	lb/MMBtu	= 1.01 EF x 0.0015%, sulfur
SO_2 emission factor in terms of SCC units:	0.208	lb/Mgal	= 1.52E-03 lb/MMBtu x 137 MMBtu/Mgal

Greenhouse Gases

> CO_2, CH_4 and N_2O emissions for diesel fuel combustion are estimated using the Distillate Fuel Oil No. 2 emission factors published in 40 CFR 98, Subpart C, Table C-1 & 2. CO_2e emissions for diesel fuel combustion are estimated using the global warming potentials published in 40 CFR 98, Subpart A, Table A-1.

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO_2	1
CH_4	28
N_2O	265

Pollutant	Emission Factor (kg/MMBtu)	Equivalent Factor (lb/Mgal)	
CO_2	73.96	22,343	40 CFR 98, Subpart C, Table C-1; Distillate Fuel Oil No. 2
CH_4	3.00E-03	0.906	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
N_2O	6.00E-04	0.181	40 CFR 98, Subpart C, Table C-2; Distillate Fuel Oil No. 2
CO_2e	74.20	22,417	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

8.2.1 Hazardous Air Pollutants

> Emission factors for organic HAP compounds expected to be emitted are based on emission factors in AP-42 Table 3.3-2 (10/96 Edition). Emission factors are converted from lb/MMBtu as provided in AP-42 to lb/Mgal as applicable to the SCC designation.

Pollutant	CAS #	HAP?	Emission Factor (lb/MMBtu)	Emission Factor (lb/Mgal)
1,3-Butadiene	106-99-0	Y	3.91E-05	5.36E-03
Acetaldehyde	75-07-0	Y	7.67E-04	1.05E-01
Acrolein	107-02-8	Y	9.25E-05	1.27E-02
Benzene	71-43-2	Y	9.33E-04	1.28E-01
Formaldehyde	50-00-0	Y	1.18E-03	1.62E-01
Naphthalene	91-20-3	Y	8.48E-05	1.16E-02
PAH		Y	1.68E-04	2.30E-02
Toluene	108-88-3	Y	4.09E-04	5.60E-02
Xylenes	1330-20-7	Y	2.85E-04	3.91E-02

8.3 Emergency Generator Potential Emissions Summary

Pollutant	Emission Factor (lb/Mgal)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NOx	159.678	= 4 g/kW-hr * 0.925 / 1.341 hp/kW	3.442	0.861
CO	112.208	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	2.419	0.605
VOC	9.657	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW	0.208	0.052
PM	6.474	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	0.140	0.035
PM10	6.474	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	0.140	0.035
PM2.5	6.474	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII)	0.140	0.035
SO2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %)	0.0045	0.0011
CO2	22,343	40 CFR 98, Subpart C, Table C-1	481.7	120.4
CH4	0.906	40 CFR 98, Subpart C, Table C-2	0.020	0.005
N2O	0.181	40 CFR 98, Subpart C, Table C-2	0.0039	0.0010
CO2e	22,417	40 CFR 98, Subpart A	483.2	120.8
Hazardous Air Pollutants				
1,3-Butadiene	0.0054	AP-42 Table 3.3-2	1.16E-04	2.89E-05
Acetaldehyde	0.105	AP-42 Table 3.3-2	2.27E-03	5.66E-04
Acrolein	0.013	AP-42 Table 3.3-2	2.73E-04	6.83E-05
Benzene	0.128	AP-42 Table 3.3-2	2.76E-03	6.89E-04
Formaldehyde	0.162	AP-42 Table 3.3-2	3.49E-03	8.71E-04
Naphthalene	0.012	AP-42 Table 3.3-2	2.50E-04	6.26E-05
PAH	0.023	AP-42 Table 3.3-2	4.96E-04	1.24E-04
Toluene	0.056	AP-42 Table 3.3-2	1.21E-03	3.02E-04
Xylenes	0.039	AP-42 Table 3.3-2	8.42E-04	2.10E-04
Total HAP	0.542	AP-42 Table 3.3-2	1.17E-02	2.92E-03

Sample Calculations:
NOx (lb/hr) = 159.678 lb/Mgal x 0.022 Mgal/hr = 3.442 lb/hr NOx
NOx (tpy) = 3.442 lb/hr x 500 hr/yr / 2,000 lb/ton = 0.861 tpy NOx

Example Spec Sheet

CLARKE®

Rating Specific Emissions Data

Nameplate Rating Information

Clarke Model	**JW6H-UFAD80**
Power Rating (BHP/kW)	**400/298**
Certified Speed (RPM)	**2100**

Refer to **Rating Data** section on page 2 for emissions output values

Rating Specific Emissions Data - John Deere Power Systems

JOHN DEERE

Rating Data

Rating	**6090HFC47B**	
Certified Power(kW)	**298**	
Rated Speed	**2100**	
Vehicle Model Number	**OEM (Clarke Fire Pump-Emergency)**	
Units	**g/kW-hr**	**g/hp-hr**
NOx	**3.50**	**2.61**
HC	**0.14**	**0.10**
NOx + HC	**N/A**	**N/A**
Pm	**0.14**	**0.10**
CO	**1.1**	**0.8**

Certificate Data

Engine Model Year	2022
EPA Family Name	NJDXL09.0114
EPA JD Name	450HAB
EPA Certificate Number	NJDXL09.0114-007
CARB Executive Order	
Parent of Family	6090HFG84A
Units	g/kW-hr
NOx	3.80
HC	0.05
NOx + HC	N/A
Pm	0.11
CO	0.9

* The emission data listed is measured from a laboratory test engine according to the test procedures of 40 CFR 89 or 40 CFR 1039, as applicable. The test engine is intended to represent nominal production hardware, and we do not guarantee that every production engine will have identical test results. The family parent data represents multiple ratings and this data may have been collected at a different engine speed and load. Emission results may vary due to engine manufacturing tolerances, engine operating conditions, fuels used, or other conditions beyond our control.

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Emissions Results by Rating run on Apr-05-2022

9. Derivation of Emissions Factors and Calculations for EU 63: Mechanical Draft Cooling Tower (10 Cells)

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 63: Mechanical Draft Cooling Tower (10 Cells) are documented in this section.

Equipment ID (SI): **63**
Emission Unit Description: Mechanical Draft Cooling Tower (10 Cells)
Equipment ID (SI): EQPT21

9.1 Process Unit(s)

Process ID: 1
EU ID - PID: 63-1
Process Description: Gallons of Recirculating Water
Control Device ID: C36
Control Device Description: Drift Eliminators
Stack ID: S-63
Stack Description: TBD
Applicable Regulation: 401 KAR 59:010, 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 38500101
SCC Description: Industrial Processes - Cooling Tower (3-85) - Process Cooling (3-85-001) - Mechanical Draft (3-85-001-01)
SCC Units: Million Gallons Cooling Water Throughput

9.2 Methodology for Defining Potential PM Emissions from Cooling Tower

9.2.1 PM Emission Factor

> As the water flows down through a cooling tower, the draft air picks up water droplets that can be emitted from the top of the tower (i.e., "drift loss"). Drift loss is minimized through the use of mist eliminators. Particulate matter emissions can result due to the presence of dissolved solids in the cooling tower water droplets that are released from the tower. As the cooling tower droplets disperse in the atmosphere, the liquid water evaporates, leaving behind solid particles in the form of particulate matter.

> Particulate matter emissions from cooling towers are estimated using the procedures of AP-42 Section 13.4 (1/1995 edition), in which PM emissions are estimated as a function of the tower flow capacity, drift loss, and total dissolved solids (TDS) in the cooling tower recirculating water.

> Cooling Tower Design Parameters:

Max Annual Operating Hours	8,760	hr/yr	
Circulating Water Flow Rate	95,000	gpm	
	5.7	MMgal/hr	95,000 gpm x 60 min/hr / 1E6 gal/MMgal = 5.7
Total Dissolved Solids (TDS) of Recirculating Water	990	ppm	
Drift Percentage for Cooling Tower Mist Eliminator	0.0010	%	
Density of Circulating Water	8.34	lb/gal	

PM emission factor based on AP-42 13.4 methodology:
PM Factor = 1.0E-05 gal drift/gal flow x 8.34 lb/gal x 990 ppm = **0.0826 lb/MMgal**

9.2.2 PM10 and PM2.5 Emission Factors

> PM_{10} and $PM_{2.5}$ emission factors are derived from the PM emission factor calculated above using the methodology presented in "Calculating Realistic PM_{10} Emissions from Cooling Towers" by Joe Reisman and Gordon Frisbie, Environmental Progress, Volume 21, Issue 2 (April 20, 2004).

> The aerodynamic diameter of a particle resulting from drift was calculated over a target droplet size distribution presented in the table below, taken from the source cited above. By interpolating on the calculated aerodynamic particle diameter, the corresponding mass percentage smaller than $PM_{2.5}$ and PM_{10} can be derived.

Droplet Diameter Size[1] (µm)	EPRI % Mass Smaller[1] (%)	Droplet Volume (μm^3)	Droplet Mass (µg)	Particle Mass (Solids) (µg)	Solid Particle Volume (μm^3)	Solid Particle Diameter (µm)	Aerodyn. Particle Diameter (µm)
10	0	524	5.24E-04	5.18E-07	0.24	0.77	1.1
20	0.196	4,189	4.19E-03	4.15E-06	1.88	1.53	2.3
22.0	***0.202***	***5,571***	***5.57E-03***	5.52E-06	***2.51***	1.69	***2.5***
30	0.226	14,137	0.01	1.40E-05	6.36	2.30	3.4
40	0.514	33,510	0.03	3.32E-05	15.08	3.07	4.5
50	1.816	65,450	0.07	6.48E-05	29.45	3.83	5.7
60	5.702	113,097	0.11	1.12E-04	50.89	4.60	6.8
70	21.348	179,594	0.18	1.78E-04	80.82	5.36	8.0
88.0	***46.937***	***356,576***	***0.36***	3.53E-04	***160.46***	6.74	***10.0***
90	49.812	381,704	0.38	3.78E-04	171.77	6.90	10.2
110	70.509	696,910	0.70	6.90E-04	314	8.43	12.5
130	82.023	1,150,347	1.15	1.14E-03	518	9.96	14.8
150	88.012	1,767,146	1.77	1.75E-03	795	11.49	17.0
180	91.032	3,053,628	3.05	3.02E-03	1,374	13.79	20.5
210	92.468	4,849,048	4.85	4.80E-03	2,182	16.09	23.9
240	94.091	7,238,229	7.24	7.17E-03	3,257	18.39	27.3
270	94.689	10,305,995	10.31	1.02E-02	4,638	20.69	30.7
300	96.288	14,137,167	14.14	1.40E-02	6,362	22.99	34.1
350	97.011	22,449,298	22.45	2.22E-02	10,102	26.82	39.8
400	98.340	33,510,322	33.51	3.32E-02	15,080	30.65	45.5
450	99.071	47,712,938	47.71	4.72E-02	21,471	34.48	51.1
500	99.071	65,449,847	65.45	6.48E-02	29,452	38.32	56.8
600	100	113,097,336	113.10	1.12E-01	50,894	45.98	68.2

Bold highlights indicate interpolated values to determine PM_{10} and $PM_{2.5}$ size fractions.

[1] Based on drift droplet size distribution testing from EPRI test facility published in the Reisman and Frisbie paper

9.2.3 Summary of PM Emission Factors

Estimated PM_{10}/PM Ratio	0.469	EPRI ratio of mass smaller than PM_{10} (based on interpolation in table above)
Estimated $PM_{2.5}$/PM Ratio	2.02E-03	EPRI ratio of mass smaller than $PM_{2.5}$ (based on interpolation in table above)

Pollutant	Emission Factor (lb/MMgal)	Basis
PM	0.0826	= 8.34 lb/gal x 990 ppm x 0.0010 drift %
PM_{10}	0.0388	= 0.0826 lb PM/MMgal circulating water x 0.469 Estimated PM10/PM Ratio
$PM_{2.5}$	1.668E-04	= 0.0826 lb PM/MMgal circulating water x 2.02E-03 Estimated PM2.5/PM Ratio

9.3 Cooling Tower Potential Emissions Summary

Pollutant	Emission Factor (lb/MMgal)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
PM	0.083	990 ppm TDS in recirculating water and 0.001% drift	0.471	2.06
PM_{10}	0.039	EPRI PM_{10}/PM ratio	0.221	0.97
$PM_{2.5}$	1.668E-04	EPRI $PM_{2.5}$/PM ratio	9.51E-04	4.16E-03

Sample Calculations:
PM (lb/hr) = 0.083 lb/MMgal x 5.7 MMgal/hr = 0.471 lb/hr PM
PM (tpy) = 0.471 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2.06 tpy PM

10. Derivation of Emissions Factors and Calculations for EU 64: Turbine Circuit Breaker

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 64: Turbine Circuit Breaker with 30 lb. SF6 circuit are documented in this section.

Equipment ID (SI): **64**
Emission Unit Description: Turbine Circuit Breaker with 30 lb. SF6 circuit
Equipment ID (SI): EQPT22

10.1 Process Unit(s)

Process ID: **1**
EU ID - PID: **64-1**
Process Description: **SF6 Releases**
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-64
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20180001
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)
SCC Units: Each-Year Facility Operating

10.3 Potential Emissions Summary

Parameter	Value	Units	Basis
Circuit Breaker Operating Hours	8760	hr/yr	
Number of Circuit Breakers	1	breakers	
Total SF_6 per Circuit Breaker	30	lb SF_6/breaker	
SF_6 Leak Rate	0.5	%	Maximum allowable leak rate
Annual SF_6 Emissions	7.50E-05	tpy	= 1 breakers * 30 lb SF6/breaker * 0.5% leak rate/yr / 2,000 lb/ton
SF_6 Global Warming Potential	23,500	lb CO_2e/lb SF_6	GWP, 100-year time horizon from 40 CFR Part 98
Annual CO_2e Emissions	1.76	tpy	= 7.50E-05 tpy SF6 Emissions * 23,500 GWP
Hourly CO_2e Emissions	0.40	lb/hr	= 1.76 tpy x 2,000 lb/ton / 8,760 hr/yr

11. Derivation of Emissions Factors and Calculations for EU 65: Lube Oil System with Demister Vents

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 65: Lube Oil System with Demister Vents are documented in this section.

Equipment ID (SI): **65**
Emission Unit Description: Lube Oil System with Demister Vents
Equipment ID (SI): EQPT23

11.1 Process Unit(s)

Process ID: **1**
EU ID - PID: **65-1**
Process Description: **Evaporative losses**
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-65
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20180001
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)
SCC Units: Each-Year Facility Operating

> The working losses conservatively assume that all lube oil consumed/replaced will evaporate and contribute to VOC emissions. Similar to LG&E/KU's Cane Run NGCC project, at most 165 gallons per year of lube oil will be added to both the GT and STG.

Max Annual Operating Hours	8,760	hr/yr	
ST and GT Lube Oil Consumption	0.50	gal/day	Process knowledge
Total Lube Oil Consumption	**0.021**	**gal/hr**	Unit Conversion: 0.5 gal/day / 24 hr/day

11.2 Lube Oil Demister Vents Potential Emissions Summary

Pollutant	Density (lb/gal)	Basis	Loss (%)	VOC EF (lb/gal)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
VOC	7.28	Lube oil density	100%	7.28	0.152	0.664

Sample Calculations:
VOC (lb/hr) = 7.281 lb/gal x 0.021 gal/hr * 100% Loss = 0.152 lb/hr VOC
VOC (tpy) = 0.152 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 0.664 tpy VOC

12. Derivation of Emissions Factors and Calculations for EU 66: Diesel Storage Tank for Generator (3,733 gal) and 67:Diesel Storage Tank for Firewater Pump (300 gal)

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 66: Diesel Storage Tank for Generator (3,733 gal) are documented in this section.

Equipment ID (SI): **66**
Emission Unit Description: Diesel Storage Tank for Generator (3,733 gal)
Equipment ID (SI): EQPT24

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 67: Diesel Storage Tank for Firewater Pump (300 gal) are documented in this section. Note that the detailed emissions calculations in this section are representative of a single GTs to be installed as part of the NGCC EGU Project.

Equipment ID (SI): **67**
Emission Unit Description: Diesel Storage Tank for Firewater Pump (300 gal)
Equipment ID (SI): EQPT25

12.1 Process Unit(s)

> The diesel tanks associated with the new emergency generator and fire pump engines serving the NGCC Plant will qualify to be classified as an insignificant activity under the Title V permit.
> This insignificant activity represents emissions from two storage tanks: one associated with the new emergency generator engine and one associated with the new fire pump engine.

Process ID: **1**
EU ID - PID: **66-1**
Process Description: **Breathing Losses**
Control Device Description: N/A
Stack ID: S-66
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code:
SCC: 42500301
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)
SCC Units: 1000 Gallon-Years Liquid Storage Capacity

Process ID: **2**
EU ID - PID: **66-2**
Process Description: **Working Losses**
Control Device Description: N/A
Stack ID: S-66
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code:
SCC: 42500302
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)
SCC Units: 1000 Gallons Liquid Throughput

Process ID: **1**
EU ID - PID: **67-1**
Process Description: **Breathing Losses**
Control Device Description: N/A
Stack ID: S-67
Stack Description: TBD

Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code:
SCC: 42500301
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)
SCC Units: 1000 Gallon-Years Liquid Storage Capacity

Process ID: 2
EU ID - PID: 67-2
Process Description: Working Losses
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-67
Stack Description: TBD
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code:
SCC: 42500302
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)
SCC Units: 1000 Gallons Liquid Throughput

Tank Volume	3,733	gal	Design specifications
	499.06	ft^3	Unit Conversion: 3733 gal x 7.48 ft3/gal
Tank Diameter	6.82	ft	Design specifications
Tank Height	13.65	ft	Design specifications
Diesel Throughput	74,500	gal/yr	Emergency diesel engine annual fuel consumption (based on 500 hr/yr): 0.149 Mgal/hr x 500 operating hrs/yr x 1000 gal/Mgal
	8.50	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Working Losses SCC rate	8.50E-03	Mgal/hr	
Breathing Losses SCC rate	4.26E-04	Mgal-Cap/hr	
Turnovers	19.96	turnovers/yr	74,500 gal/yr / 3733 gal = 19.96 turnovers/yr
True Vapor Pressure	0.0070	psia	Calculated by TankESP
Bulk Liquid Storage	59.00	°F	Calculated by TankESP
Average Liquid Surface	62.16	°F	Calculated by TankESP

Tank Volume	300	gal	Design specifications
	40.11	ft^3	Unit Conversion: 300 gal x 7.48 ft3/gal
Tank Diameter	2.94	ft	Design specifications
Tank Height	5.89	ft	Design specifications
Diesel Throughput	10,779	gal/yr	Fire pump diesel engine annual fuel consumption (based on 500 hr/yr): 0.022 Mgal/hr x 500 operating hrs/yr x 1000 gal/Mgal
	1.23	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Working Losses SCC rate	1.23E-03	Mgal/hr	
Breathing Losses SCC rate	3.42E-05	Mgal-Cap/hr	
Turnovers	35.93	turnovers/yr	10,779 gal/yr / 300 gal = 35.93 turnovers/yr
True Vapor Pressure	0.0076	psia	Calculated by TankESP
Bulk Liquid Storage	59.00	°F	Calculated by TankESP
Average Liquid Surface	64.67	°F	Calculated by TankESP

12.2 Diesel Storage Tanks Potential Emissions Summary

Storage Tank	Pollutant	Standing Loss Emission Factor (lb/Mgal-cap)	Working Loss Emission Factor (lb/Mgal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
Emergency Generator	VOC	4.186	1.13E-03	TankESP analysis using methodology presented in AP-42 Section 7.1	15.625	0.084	1.79E-03	8E-03
Fire Pump	VOC	0.257	5.85E-04		0.077	0.006	9.51E-06	4.2E-05

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

13. Derivation of Emissions Factors and Calculations for EU 68: NGCC Haul Roads

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for 68: NGCC Haul Roads are documented in this section.

Emission Unit ID: **68**
Emission Unit Name: NGCC Haul Roads
Equipment ID (SI): AREA5

13.1 Process Units

Process ID: **1**
EU ID - PID: **68-1**
Process Description: **Paved Aq. NH3 Transport**
Control Device Description: Dust Suppression
Applicable Regulation: 401 KAR 63:010; 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30502011
SCC Description: Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)
SCC Units: Miles Vehicle Travelled

Process ID: **2**
EU ID - PID: **68-2**
Process Description: **Paved Cooling Twr Chemicals Transport**
Control Device Description: Dust Suppression
Applicable Regulation: 401 KAR 63:010; 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30502011
SCC Description: Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)
SCC Units: Miles Vehicle Travelled

Process ID: **3**
EU ID - PID: **68-3**
Process Description: **Paved Water Treatment Chemicals Transport**
Control Device Description: Dust Suppression
Applicable Regulation: 401 KAR 63:010; 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30502011
SCC Description: Industrial Processes - Mineral Products (3-05) - Stone Quarrying - Processing (See also 305320) (3-05-020) - Hauling (3-05-020-11)
SCC Units: Miles Vehicle Travelled

13.2 Annual Material Process Rates

> Road emissions are grouped into one of 3 categories based on type of truck-- aqueous ammonia, cooling tower chemicals, and water treatment chemicals.

> For aqueous ammonia, cooling tower chemicals, and water treatment chemicals, VMT can be estimated each year based on the tons of material received and the approximate weight of material carried per trip.

> Annual material process rate totals listed below are estimates of maximum deliveries via truck.

	Annual Total (tons)	Full Truck Weight (tons)	Empty Truck Weight (tons)	Material Per Trip (tons)	Annual Trips (trips/yr)
Aqueous Ammonia Delivered	3,125	30.0	16	14	223
Cooling Tower Chemicals Delivered	1,267	31.4	16.0	15	82
Water Treatment Chemicals Delivered	24	12.0	10	2	12

13.4 Truck Routes and Mileage

> The round trip distance each type of truck takes while on-site, and the portion unpaved and paved, are estimated based on site plan drawings.

	On-Site Round-Trip Distance (mi)	Annual Trips (trips/yr)	Annual VMT (VMT/yr)	% of Route Unpaved	% of Route Paved	Unpaved VMT (VMT/yr)	Paved VMT (VMT/yr)
Aqueous Ammonia Delivered	2.1	223	465	0%	100%	0	465
Cooling Tower Chemicals Delivered	2.1	82	171	0%	100%	0	171
Water Treatment Chemicals Delivered	1.9	12	23	0%	100%	0	23

13.5 Unpaved Road Emission Factors

> The methodology presented in AP-42 Section 13.2.2 (11/2006) was used to derive fugitive PM emission factors for truck traffic on unpaved road surfaces within the plant.

> The following emission factor equation applies: (Equations 1a and 2 in AP42 13.2.2)

$E\ (lb/VMT) = [(k)(s/12)^{a}(W/3)^{b}]((365-P)/365)$

where:		PM	PM10	PM2.5
k	Particle Size Multiplier (lb/VMT)	4.9	1.5	0.15
a	Constant	0.7	0.9	0.9
b	Constant	0.45	0.45	0.45
s	Surface Material Silt Content (%)	3.9	3.9	3.9
P	Days with Precipitation	125	125	125

> The road surface silt content value is that used by EPA in the 1999 National Emissions Inventory for unpaved roads in Kentucky.

> Estimated mean number of days with 0.01 inch or more of precipitation for central Kentucky is from AP-42 Figure 13.2.2-1 (11/2006).

> For purposes of representing emissions in the Title V renewal application, the control efficiency provided by existing road dust suppression methods and work practices is not accounted for, which results in a conservative estimate of PM fugitive emissions.

Aqueous Ammonia Trucks		PM	PM10	PM2.5
W	Average Vehicle Weight (tons)	23	23	23
E	Uncontrolled Emission Factor (lb/VMT)	3.669	0.897	0.090
Cooling Tower Chemical Trucks				
W	Average Vehicle Weight (tons)	24	24	24
E	Uncontrolled Emission Factor (lb/VMT)	3.719	0.909	0.091
Water Treatment Chemical Trucks				
W	Average Vehicle Weight (tons)	11	11	11
E	Uncontrolled Emission Factor (lb/VMT)	2.632	0.644	0.064

13.6 Paved Road Emission Factors

> The methodology presented in AP-42 Section 13.2.1 (11/2006) was used to derive fugitive PM emission factors for truck traffic on paved road surfaces within the plant.

> The following emission factor equation applies: (Equation 2 in AP43 13.2.1)

$E\ (lb/VMT) = [(k)(sL/2)^{0.65}(W/3)^{1.5} - C](1-(P/4N))$

where:		PM	PM10	PM2.5
k	Particle Size Multiplier (lb/VMT)	0.082	0.016	0.0024
sL	Silt Loading (g/m2)	0.6	0.6	0.6
C	Factor for Exhaust, Brake Wear & Tire Wear (lb/VMT)	0.00047	0.00047	0.00036
P	Days with Precipitation	125	125	125
N	Number of days in averaging period	365	365	365

> The road surface silt loading value is from AP42 Table 13.2.1-3 (11/2006) for the <500 ADT category.
> C value is from AP42 Table 13.2.1-2 (11/2006). PM30 is used as a surrogate for PM.
> Estimated mean number of days with 0.01 inch or more of precipitation for central Kentucky is from AP-42 Figure 13.2.1-2 (11/2006).
> For purposes of representing emissions in the Title V renewal application, the control efficiency provided by existing road dust suppression methods and work practices is not accounted for, which results in a conservative estimate of PM fugitive emissions.

Aqueous Ammonia Trucks	PM	PM10	PM2.5
W Average Vehicle Weight (tons)	23	23	23
E Uncontrolled Emission Factor (lb/VMT)	0.727	0.142	0.021
Cooling Tower Chemical Trucks			
W Average Vehicle Weight (tons)	24	24	24
E Uncontrolled Emission Factor (lb/VMT)	0.761	0.148	0.022
Water Treatment Chemical Trucks			
W Average Vehicle Weight (tons)	11	11	11
E Uncontrolled Emission Factor (lb/VMT)	0.240	0.047	0.007

13.7 Fugitive PM Emissions from Roads

Truck Category	Unpaved Road Miles (VMT/yr)	Unpaved Road Factor (lb/VMT)	Unpaved Road Emissions (tpy)	Paved Road Miles (VMT/yr)	Paved Road Factor (lb/VMT)	Paved Road Emissions (tpy)	Total Road Emissions (tpy)	Hourly Average Emissions (lb/hr)
PM								
Aqueous Ammonia Delivered	-	3.67	-	465	0.727	0.1691	0.169	0.0386
Cooling Tower Chemicals Delivered	-	3.72	-	171	0.761	0.0651	0.065	0.0149
Water Treatment Chemicals Delivered	-	2.63	-	23	0.240	0.0027	0.003	0.0006
TOTAL	-		-	659		0.2370	0.237	0.0541
					Overall SCC Factor (lb/VMT):		**0.719**	
PM10								
Aqueous Ammonia Delivered	-	0.90	-	465	0.142	0.0329	0.033	0.0075
Cooling Tower Chemicals Delivered	-	0.91	-	171	0.148	0.0127	0.013	0.0029
Water Treatment Chemicals Delivered	-	0.64	-	23	0.047	0.0005	0.001	0.0001
TOTAL	-		-	659		0.0461	0.046	0.0105
					Overall SCC Factor (lb/VMT):		**0.140**	
PM2.5								
Aqueous Ammonia Delivered	-	0.09	-	465	0.021	0.0049	0.005	0.0011
Cooling Tower Chemicals Delivered	-	0.09	-	171	0.022	0.0019	0.002	0.0004
Water Treatment Chemicals Delivered	-	0.06	-	23	0.007	0.0001	0.000	0.0000
TOTAL	-		-	659		0.0068	0.007	0.0016
					Overall SCC Factor (lb/VMT):		**0.021**	

14. Derivation of Emissions Factors and Calculations for EU 69: Natural Gas Piping Fugitives

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for EU 69: Natural Gas Piping Fugitives are documented in this section.

Equipment ID (SI): **69**
Emission Unit Description: Natural Gas Piping Fugitives
Equipment ID (SI): EQPT26

14.1 Process Units

Process ID: **1**
EU ID - PID: **69-1**
Process Description: **Gas/Vapor Valves**
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30600811
SCC Description: Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Pipeline Valves: Gas Streams (3-06-008-11)
SCC Units: Each-Year Valve Operating

Process ID: **2**
EU ID - PID: **69-2**
Process Description: **Relief Valves**
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30600822
SCC Description: Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Vessel Relief Valves: All Streams (3-06-008-22)
SCC Units: Each-Year Valve Operating

Process ID: **3**
EU ID - PID: **69-3**
Process Description: **Flanges**
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30600816
SCC Description: Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Flanges: All Streams (3-06-008-16)
SCC Units: Each-Year Flange Operating

Process ID: **4**
EU ID - PID: **69-4**
Process Description: **Vents**
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 20180001
SCC Description: Internal Combustion Engines - Electric Generation (2-01) - Equipment Leaks (2-01-800) - Equipment Leaks (2-01-800-01)
SCC Units: Each-Year Facility Operating

Process ID: **5**
EU ID - PID: **69-5**
Process Description: **Compressors Components**
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30600819
SCC Description: Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Compressor Seals: Gas Streams (3-06-008-19)
SCC Units: Each-Year Seal Operating

Process ID: **6**
EU ID - PID: **69-6**
Process Description: **Sampling Connections**
Control Device Description: N/A
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? Yes
Count Emissions for PTE? Yes

Source Classification Code
SCC: 30600811
SCC Description: Industrial Processes - Petroleum Industry (3-06) - Fugitive Emissions (3-06-008) - Pipeline Valves: Gas Streams (3-06-008-11)
SCC Units: Each-Year Valve Operating

14.2 Natural Gas Piping Fugitives Component Counts

> The total component counts below represent new natural gas piping components to be installed as part of the NGCC project.

Component Type	NGCC	Total Components
Valves	304	304
Relief Valves	25	25
Flanges	496	496
Vents	69	69
Compressors	3	3
Sampling Connections	3	3

14.3 Derivation and Documentation of Emission Factors for Natural Gas Piping Fugitives

> The emission factors presented below are from EPA's Protocol for Equipment Leak Emissions Estimates (Document EPA-453/R-95/017, November 1995), Page 2-15. These emission factors are representative of oil and gas production operations and as such are appropriate to use for estimating natural gas piping fugitive emissions.

Component Type	Emission Factor (kg/hr/comp.)[1]	VOC Content of Pipeline Gas (wt. %)	VOC Emission Factor (kg/hr/comp.)[2]	VOC Emission Factor (lb/yr/comp.)	CO2 Content of Pipeline Gas (wt. %)	CO2 Emission Factor (kg/hr/comp.)	CO2 Emission Factor (lb/yr/comp.)	CH4 Content of Pipeline Gas (wt. %)	CH4 Emission Factor (kg/hr/comp.)	CH4 Emission Factor (lb/yr/comp.)
Valves	4.50E-03	0.38%	1.70E-05	0.329	3.69%	1.66E-04	3.209	84.7%	3.81E-03	73.594
Relief Valves[3]	8.80E-03	0.38%	3.33E-05	0.644	3.69%	3.25E-04	6.275	84.7%	7.45E-03	143.917
Flanges	3.90E-04	0.38%	1.48E-06	0.029	3.69%	1.44E-05	0.278	84.7%	3.30E-04	6.378
Vents[3]	8.80E-03	0.38%	3.33E-05	0.644	3.69%	3.25E-04	6.275	84.7%	7.45E-03	143.917
Compressors[3]	8.80E-03	0.38%	3.33E-05	0.644	3.69%	3.25E-04	6.275	84.7%	7.45E-03	143.917
Sampling Connections	8.80E-03	0.38%	3.33E-05	0.644	3.69%	3.25E-04	6.275	84.7%	7.45E-03	143.917

[1] These emission factors exclude non-VOC contributions from methane and ethane.
[2] VOC EF = TOC EF * VOC wt. %
[3] Emissions from pressure relief valves are rolled into the "Other" category.

14.4 Potential Emissions Summary for Natural Gas Piping Fugitives

Pollutant	Capacity (comp./hr)	Emission Factor (lb/yr/comp.)	Basis	Potential Emissions (lb/yr)	Potential Emissions (tpy)
Valves					
VOC	0.0347	0.329	Document EPA-453/R-95/017, November 1995	100	0.050
CO_2	0.0347	3.209	Document EPA-453/R-95/017, November 1995	976	0.488
CH_4	0.0347	73.594	Document EPA-453/R-95/017, November 1995	22,373	11.186
CO_2e	0.0347	2,064	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	627,407	313.704
Relief Valves					
VOC	0.0029	0.644	Document EPA-453/R-95/017, November 1995	16	0.008
CO_2	0.0029	6.275	Document EPA-453/R-95/017, November 1995	157	0.078
CH_4	0.0029	143.917	Document EPA-453/R-95/017, November 1995	3,598	1.799
CO_2e	0.0029	4,036	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	100,899	50.449
Flanges					
VOC	0.0566	0.029	Document EPA-453/R-95/017, November 1995	14	0.007
CO_2	0.0566	0.278	Document EPA-453/R-95/017, November 1995	138	0.069
CH_4	0.0566	6.378	Document EPA-453/R-95/017, November 1995	3,164	1.582
CO_2e	0.0566	179	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	88,718	44.359
Vents					
VOC	0.0079	0.644	Document EPA-453/R-95/017, November 1995	44	0.022
CO_2	0.0079	6.275	Document EPA-453/R-95/017, November 1995	433	0.217
CH_4	0.0079	143.917	Document EPA-453/R-95/017, November 1995	9,930	4.965
CO_2e	0.0079	4,036	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	278,481	139.240
Compressors					
VOC	3.42E-04	0.644	Document EPA-453/R-95/017, November 1995	2	0.001
CO_2	3.42E-04	6.275	Document EPA-453/R-95/017, November 1995	19	0.009
CH_4	3.42E-04	143.917	Document EPA-453/R-95/017, November 1995	432	0.216
CO_2e	3.42E-04	4,036	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	12,108	6.054
Sampling Connections					
VOC	3.42E-04	0.644	Document EPA-453/R-95/017, November 1995	2	0.001
CO_2	3.42E-04	6.275	Document EPA-453/R-95/017, November 1995	19	0.009
CH_4	3.42E-04	143.917	Document EPA-453/R-95/017, November 1995	432	0.216
CO_2e	3.42E-04	4,036	CO_2 * CO_2 GWP + CH_4 * CH_4 GWP	12,108	6.054
Total Potential Emissions					
VOC				**179**	**0.07**
CO_2				**1,741**	**0.64**
CH_4				**39,928**	**14.78**
CO_2e				**1,119,720**	**415**

15. Derivation of Emissions Factors and Calculations for EU 70: 93% Sulfuric Acid Tank

> Emission factors and control efficiencies for the pollutants represented on the 7007N form for 70: 93% Sulfuric Acid Tank are documented in this section.

Emission Unit ID: 70
Emission Unit Description: 93% Sulfuric Acid Tank
Equipment ID (SI): EQPT27

15.1 Process Unit(s)

Process ID: **1**
EU ID - PID: **70-1**
Process Description: **Breathing Losses**
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-70
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500301
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Breathing Loss (4-25-003-01)
SCC Units: 1000 Gallon-Years Liquid Storage Capacity

Process ID: **2**
EU ID - PID: **70-2**
Process Description: **Working Losses**
Control Device ID: N/A
Control Device Description: N/A
Stack ID: S-70
Applicable Regulation: 401 KAR 51:017
Construction Date: 6/22/2026
Fugitive Emissions? No
Count Emissions for PTE? Yes

Source Classification Code
SCC: 42500302
SCC Description: Petroleum and Solvent Evaporation - Fixed Roof Tanks (4-25) - (1,000 Bbl Size) (4-25-003) - Working Loss (4-25-003-02)
SCC Units: 1000 Gallons Liquid Throughput

Max Annual Operating Hours	8,760	hr/yr	
Tank Volume	12,200	gal	Design specification
	1,630.9	ft^3	Unit Conversion: 12200 gal * 7.48 ft3/gal
Tank Length	22.00	ft	Design specification
Tank Diameter	10.00	ft	Design specification
H_2SO_4 Throughput	146,400	gal/yr	Conservative estimate for annual facility-wide consumption
	16.71	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	12.00	turnovers/yr	= 146,400 gal/yr / 12,200 gal
True Vapor Pressure	1.16E-05	psia	Calculated by TankESP
Bulk Liquid Storage	56.51	°F	Calculated by TankESP
Average Liquid Surface	60.69	°F	Calculated by TankESP

15.2 Potential Emissions Summary for 93% Sulfuric Acid Tank

Storage Tank	Pollutant	Standing Loss Emission (lb/Mgal-cap)	Working Loss Emission Factor (lb/Mgal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
Sulfuric Acid Tank	H_2SO_4	6.60E-05	4.37E-07	TankESP analysis using methodology presented in AP-42 Section 7.1 and sulfuric acid partial pressure data from Perry's Chemical Engineer's Handbook, 8th Edition	8.05E-04	6.39E-05	9.92E-08	4.3E-07

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

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APPENDIX C. AIR PERMIT APPLICATION FORMS

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007AI

Administrative Information

___ Section AI.1: Source Information
___ Section AI.2: Applicant Information
___ Section AI.3: Owner Information
___ Section AI.4: Type of Application
___ Section AI.5: Other Required Information
___ Section AI.6: Signature Block
___ Section AI.7: Notes, Comments, and Explanations

Additional Documentation

None

___ Additional Documentation attached

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)

KY EIS (AFS) #: 21- 167-00001

Permit #: V-17-030 R1

Agency Interest (AI) ID: 3148

Date: March 25, 2025

Section AI.1: Source Information

Physical Location Address:	**Street:**	815 Dix Dam Road				
	City:	Harrodsburg	**County:**	Mercer	**Zip Code:**	40330
Mailing Address:	**Street or P.O. Box:**	32010				
	City:	Louisville	**State:**	Kentucky	**Zip Code:**	40232

Standard Coordinates for Source Physical Location

Longitude: -84.715263 (decimal degrees) **Latitude:** 37.789261 (decimal degrees)

Primary (NAICS) Category: Fossil Fuel Electric Power **Primary NAICS #:** 221112

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Classification (SIC) Category: Electric Services **Primary SIC #:** 4911

Briefly discuss the type of business conducted at this site: Electric generating power plant. Existing operations consist of one pulverized coal utility boiler and associated raw material and support operations, and seven simple cycle peaking turbines.

Description of Area Surrounding Source: ☑ Rural Area ☐ Industrial Park ☐ Residential Area ☐ Urban Area ☐ Industrial Area ☐ Commercial Area

Is any part of the source located on federal land? ☐ Yes ☑ No

Number of Employees: Approximately 95

Approximate distance to nearest residence or commercial property: < 1 mile

Property Area: 1,222.1 acres

Is this source portable? ☐ Yes ☑ No

What other environmental permits or registrations does this source currently hold or need to obtain in Kentucky?

NPDES/KPDES:	☑ Currently Hold	☐ Need	☐ N/A
Solid Waste:	☑ Currently Hold	☐ Need	☐ N/A
RCRA:	☑ Currently Hold	☐ Need	☐ N/A
UST:	☐ Currently Hold	☐ Need	☑ N/A

Type of Regulated Waste Activity:

☐ Mixed Waste Generator ☑ Generator ☐ Recycler ☐ Other: _____

☐ U.S. Importer of Hazardous Waste ☐ Transporter ☐ Treatment/Storage/Disposal Facility ☐ N/A

Section AI.2: Applicant Information

Applicant Name: Kentucky Utilities Company (E.W. Brown Generating Station)

Title: (if individual)

Mailing Address: **Street or P.O. Box:** 820 West Broadway
City: Louisville **State:** KY **Zip Code** 40232

Email: (if individual) Not Applicable

Phone: 502-627-2343

Technical Contact

Name: Brandan Burfict

Title: Sr. Manager, Environmental Generation and Gas Operations

Mailing Address: **Street or P.O. Box:** 820 West Broadway
City: Louisville **State:** KY **Zip Code** 40232

Email: brandan.burfict@lge-ku.com

Phone: 502-627-2791

Air Permit Contact for Source

Name: Same as Technical Contact

Title:

Mailing Address: **Street or P.O. Box:**
City: **State:** **Zip Code**

Email:

Phone:

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Section AI.3: Owner Information

☑ **Owner same as applicant**

Name:

Title:

Mailing Address: **Street or P.O. Box:**

City: **State:** **Zip Code**

Email:

Phone:

List names of owners and officers of the company who have an interest in the company of 5% or more.

Name	Position
LG&E and KU Energy LLC owns 100% common stock of Louisville Gas & Electric Company and Kentucky Utilities Company	

Section AI.4: Type of Application

Current Status: ☑ Title V ☐ Conditional Major ☐ State-Origin ☐ General Permit ☐ Registration ☐ None

Requested Action: *(check all that apply)*

☐ Name Change	☐ Initial Registration	☑ Significant Revision	☐ Administrative Permit Amendment
☐ Renewal Permit	☐ Revised Registration	☐ Minor Revision	☐ Initial Source-wide Operating Permit
☐ 502(b)(10)Change	☐ Extension Request	☐ Addition of New Facility	☐ Portable Plant Relocation Notice
☐ Revision	☐ Off Permit Change	☐ Landfill Alternate Compliance Submittal	☐ Modification of Existing Facilities
☐ Ownership Change	☐ Closure		

Requested Status: ☐ Title V ☐ Conditional Major ☐ State-Origi ☑ PSD ☐ NSR ☐ Other: _____

Is the source requesting a limitation of potential emissions? ☑ Yes ☐ No

Pollutant:	Requested Limit:	Pollutant:	Requested Limit:
☐ Particulate Matter		☐ Single HAP	
☐ Volatile Organic Compounds (VOC)		☐ Combined HAPs	
☐ Carbon Monoxide		☐ Air Toxics (40 CFR 68, Subpart F)	
☐ Nitrogen Oxides		☐ Carbon Dioxide	
☐ Sulfur Dioxide		☐ Greenhouse Gases (GHG)	
☐ Lead		☑ Other	< 4000 hr/yr for Aux Boiler

For New Construction:

Proposed Start Date of Construction: *(MM/YYYY)* 06/22/2026

Proposed Operation Start-Up Date: *(MM/YYYY)* 6/1/2029 - 6/1/2030

For Modifications:

Proposed Start Date of Modification: *(MM/YYYY)* N/A

Proposed Operation Start-Up Date: *(MM/YYYY)* N/A

Applicant is seeking coverage under a permit shield. ☑ **Yes** ☐ **No**

Identify any non-applicable requirements for which permit shield is sought on a separate attachment to the application.

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Section AI.5 Other Required Information

Indicate the documents attached as part of this application:

- [x] DEP7007A Indirect Heat Exchangers and Turbines
- [x] DEP7007B Manufacturing or Processing Operations
- [ ] DEP7007C Incinerators and Waste Burners
- [ ] DEP7007F Episode Standby Plan
- [x] DEP7007J Volatile Liquid Storage
- [ ] DEP7007K Surface Coating or Printing Operations
- [ ] DEP7007L Mineral Processes
- [ ] DEP7007M Metal Cleaning Degreasers
- [x] DEP7007N Source Emissions Profile
- [ ] DEP7007P Perchloroethylene Dry Cleaning Systems
- [ ] DEP7007R Emission Offset Credit
- [ ] DEP7007S Service Stations
- [ ] DEP7007T Metal Plating and Surface Treatment Operations
- [x] DEP7007V Applicable Requirements and Compliance Activities
- [ ] DEP7007Y Good Engineering Practice and Stack Height Determination
- [ ] DEP7007AA Compliance Schedule for Non-complying Emission Units
- [ ] DEP7007BB Certified Progress Report
- [x] DEP7007CC Compliance Certification See CY2024 ACC
- [x] DEP7007DD Insignificant Activities
- [x] DEP7007EE Internal Combustion Engines
- [ ] DEP7007FF Secondary Aluminum Processing
- [x] DEP7007GG Control Equipment
- [x] DEP7007HH Haul Roads
- [ ] Confidentiality Claim
- [ ] Ownership Change Form
- [ ] Secretary of State Certificate
- [x] Flowcharts or diagrams depicting process
- [ ] Digital Line Graphs (DLG) files of buildings, roads, etc.
- [x] Site Map
- [x] Map or drawing depicting location of facility
- [ ] Safety Data Sheet (SDS)
- [ ] Emergency Response Plan
- [x] Other: Application Report
  Acid Rain Permit Application

Section AI.6: Signature Block

I, the undersigned, hereby certify under penalty of law, that I am a responsible official*, and that I have personally examined, and am familiar with, the 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 information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

DocuSigned by:
Steven B. Turner
8AD647306F3F4A0...

Authorized Signature

3/25/2025

Date

Steven Turner

Type or Printed Name of Signatory

Vice President, Generation

Title of Signatory

*Responsible official as defined by 401 KAR 52:001.

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Section AI.7: Notes, Comments, and Explanations

Clarification of AI.1 Permits/Registrations:

Kentucky Division of Waste Management Certificate of Registration-EPA ID #KYD-000-622-951
Kentucky Division of Water KPDES Permit #KY 0002020
US DOT Hazardous Material Certificate of Registration # 060619550228B
KY Division of Waste Management, Special Waste Landfill Permit (#SW 084-00010)

Division of Waste Management Certificate of Registration annual renewal
KPDES Permit Renewal every five years
US DOT Hazardous Material Certificate of Registration annual renewal

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Division for Air Quality
300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007DD

Insignificant Activities

Section DD.1: Table of Insignificant Activities
Section DD.2: Signature Block
___ Section DD.3: Notes, Comments, and Explanations

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AF 21- 167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: March 25, 2025

Section DD.1: Table of Insignificant Activities

*Identify each activity with a unique Insignificant Activity number (IA #); for example: 1, 2, 3… etc.

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
1	Station fuel-oil tanks (2 @ 1,100,000 gallons each)	T-1 & T-2 (South CT area)	NA	VOC: 0.20 tpy
2	#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973	T-10 525,000 (Fuel oil Storage & Unit 3 Light off Tank)	NA	VOC: 0.10 tpy
3	Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each)	T-17 & T-18 (Steam Plant/Unit 3 Clean/Dirty Turbine Oil)	NA	VOC: <0.01 tpy
4	Unleaded gasoline storage tanks	T-25 (Coal Yard/Tractor Garage Area)	NA	VOC: 0.10 tpy
5	Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons)	R3, R6, R7	NA	VOC: <0.01 tpy
6	Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons)	R8, R9, R10, R11	NA	VOC: <0.01 tpy
7	Burning of Off-Specification Used Oil for Energy Recovery		401 KAR 61:020	
8	Kerosene Tank (500 gallons)	T-26 (Coal Yard/Tractor Garage Area)	NA	VOC: <0.01 tpy

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Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
9	Distillate Oil and/or Propane Coal Belt Heaters		NA	
10	Limestone Storage Pile		401 KAR 63.010	PM: 0.134 tpy PM10: 0.067 tpy PM2.5: 0.010 tpy
11	Limestone Reclaim Maintenance Tunnel Exhaust Vent		401 KAR 59:010	PM: 0.050 tpy PM10: 0.017 tpy PM2.5: <0.01 tpy
12	Sorbent Storage Silos (for SO3 mitigation)		401 KAR 59:010	PM/PM10/PM2.5: <0.01 tpy
13	Natural Gas Distillate tank (2,000 gallons)	T-9 (CT area)	NA	VOC: 0.20 tpy
14	Diesel Fuel tanks for emergency generators (3 @ 391 gallons)	T3, T4, T5 (CT area/Emergency Generators)	NA	VOC: <0.01 tpy
15	Diesel Fuel tank for emergency fire pump (300 gallons)	T-8 (CT area/emergency fire pump AST)	NA	VOC: <0.01 tpy
16	Liquid Hg Control Additives		NA	
17	Diesel Fuel tank for emergency generator (837 gallons)	T-14 (Steam Plant/Unit 3 Emergency Generator)	NA	VOC: <0.01 tpy
18	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons)	T-20, T-21 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)	NA	VOC: <0.01 tpy
19	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons)	T-22, T-23 (Steam Plant, Emergency Fire Pumps & FGD Quench Water Building)	NA	VOC: <0.01 tpy
20	Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons)	R4, R44	NA	VOC: <0.01 tpy
21	Turbine oil reservoir for Unit 3 seal oil (150 gallons)	R14	NA	VOC: <0.01 tpy
22	Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons)	R18, R19 (Unit 3, outside out of service ESP)	NA	VOC: <0.01 tpy
23	Lab Fume Hood		NA	

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
24	Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons)	T27, T28, T29 (Tractor Garage Building Read Area)	NA	VOC: <0.01 tpy
25	PAC Storage Silos		401 KAR 59:010	PM/PM10/PM2.5: <0.01 tpy
26	Bottom Ash Transport		401 KAR 63.010	
27	Fly Ash Transport		401 KAR 63.010	
28	Gypsum Transport & Process Water System Solids		401 KAR 63.010	PM: 0.842 tpy PM10: 0.168 tpy PM2.5: 0.041 tpy
29	Landfill Truck Loading and Unloading & Process Water System Solids		401 KAR 63.010	PM: 0.126 tpy PM10: 0.060 tpy PM2.5: <0.01 tpy
30	Active Area of the CCR Landfill & Process Water System Solids (Wind Erosion)		401 KAR 63.010	PM: 1.18 tpy PM10: 0.589 tpy PM2.5: 0.088 tpy
31	Slipstream Carbon Dioxide (CO2) capture System – Research		401 KAR 63.010	PM/PM10/PM2.5: <0.01 tpy
32	Bottom Ash Handling including storage pile (associated with CCR landfill operations)		401 KAR 63.010	PM: 0.050 tpy PM10: 0.025 tpy PM2.5: <0.01 tpy
33	Fly Ash Handling including load out to trucks (associated with CCR landfill operations)		401 KAR 63.010	PM: 0.911 tpy PM10: 0.431 tpy PM2.5: 0.065 tpy
34	Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)		401 KAR 63.010	PM/PM10: 0.863 tpy PM2.5: 0.604 tpy
35	Fly Ash Storage Silos (2) (associated with CCR landfill operations)		401 KAR 59.010	PM/PM10: 0.691 tpy PM2.5: 0.484 tpy
36	Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)		401 KAR 63.010	PM: 0.232 tpy PM10: 0.113 tpy PM2.5: 0.017 tpy
37	NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)		NA	

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Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
38	Diesel Fuel tanks for emergency generators (2 @ 900 gallons)	T-6, T-7 CT area/between CT7 & CT8(EU28 & EU25)	NA	VOC: <0.01 tpy
39	Diesel Fuel Tanks (500, 2000, 3@ 550, 1100 gallons)	T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)	NA	VOC: <0.01 tpy
40	Mobile Diesel Fuel Tank (251 gallons/square tank)	T-39 (Stored in CT Warehouse when not in use)	NA	VOC: <0.01 tpy
41	Unit 3 Propylene Glycol Tank (3,000 gal)		NA	VOC: <0.01 tpy
42	Hydroelectric Building Lube Oil Tanks (T-31 and T-32)		NA	VOC: <0.01 tpy
43	CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)		NA	Negligible
44	Unit 3 Hydrazine Monohydrate Tote (180 gal)		NA	Negligible
45	Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)		401 KAR 59:010	PM/PM10/PM2.5: 0.75 tpy
	NOTE: Blue font are existing IAs. New Insignificant Activities being added to Section C of the Title V permit via the Title V permit renewal are shown in green font.			

Section DD.2: Signature Block

I, THE UNDERSIGNED, HEREBY CERTIFY UNDER PENALTY OF LAW, THAT I AM A RESPONSIBLE OFFICIAL, AND THAT I HAVE PERSONALLY EXAMINED, AND AM FAMILIAR WITH, THE 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 INFORMATION IS ON KNOWLEDGE AND BELIEF, TRUE, ACCURATE, AND COMPLETE. I AM AWARE THAT THERE ARE SIGNIFICANT PENALTIES FOR SUBMITTING FALSE OR INCOMPLETE INFORMATION, INCLUDING THE POSSIBILITY OF FINE OR IMPRISONMENT.

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Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions

By:

DocuSigned by:
Steven B. Turner
8AD647306F3F4A0...

Authorized Signature

3/25/2025

Date

Steven Turner

Type/Print Name of Signatory

Vice President, Generation

Title of Signatory

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

Section DD.3: Notes, Comments, and Explanations

Insignificant Activities listed on the form in blue font are existing. New Insignificant Activities being added to Section C of the Title V permit via the Title V permit renewal application in green font.

Refer to prior applications for emission calculations for existing insignificant activities.

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007A

Indirect Heat Exchangers and Turbines

___ Section A.1: General Information
___ Section A.2: Operating and Fuel Information
___ Section A.3: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG.
____ Manufacturer's specifications

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AFS) #: 21-167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: March 25, 2025

Section A.1: General Information

Emission Unit #	Emission Unit Name	Process ID	Process Name	Identify General Type: Indirect Heat Exchanger, Gas Turbine, or Combustion Turbine	Indirect Heat Exchanger Configuration	Manufacturer	Model No./ Serial No.	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	SCC Code	SCC Units	Control Device ID	Stack ID
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	1	Natural Gas Firing in GT & DB	Gas Turbine and HRSG with Duct Burner	na	GE 7HA.03		06/2026	20100201	MMCF	C34, C35	S-58
		2	Natural Gas Firing in GT						20100201	MMCF	na	S-58
		3	Cold Startup Events						39999993	Event	na	S-58
		4	Warm Startup Events						39999993	Event	na	S-58
		5	Hot Startup Events						39999993	Event	na	S-58
		6	Shutdown Events						39999993	Event	na	S-58
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	Indirect Heat Exchanger	Boiler	Rentech, M0500		06/2026	10200602	MMCF	na	S-59
COMB21, 60	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15.65 MMBtu/hr)	Process Heater	Process Heater	OGI-TERI, < 20 MMBtu/hr		06/2026	39990003	MMCF	na	S-60

Section A.2: Operating and Fuel Information

Emission Unit #	If multipurpose unit, identify the percentage of use by purpose				Rated Capacity Heat Input *(MMBTU/hr)*	Rated Capacity Power Output		Describe Operating Scenario (only if this unit will be used in different configurations)	Classify Fuel as Primary or Secondary	Identify Fuel Type: Coal, Natural Gas, Wood, Biomass, Landfill/Digester Gas, Fuel Oil # (specify 1-6), or Other	Heat Content (HHV)		Maximum Operating Hours	Ash Content *(%)*	Sulfur Content *(%)*
	Space Heat	Process Heat	Power	Emergency			*(Specify units: hp, MW, or lb steam/hr)*					*(Specify units: Btu/lb, Btu/gal, or Btu/scf)*			
COMB19, 58	0	0	100	na	4895 for GT 4525 for NGCC	681	MW-g	Refer to Section 5 in Appendix B of application.	Primary	Natural Gas	1,053	Btu/scf	8,760	na	0.5 gr/Ccf
COMB20, 59	0	100	0	na	95.52	na	na	na	Primary	Natural Gas	1,053	Btu/scf	4,000	na	0.5 gr/Ccf
COMB21, 60	0	100	0	na	15.65	na	na	na	Primary	Natural Gas	1,053	Btu/scf	8,760	na	0.5 gr/Ccf

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Section A.3: Notes, Comments, and Explanations

Refer to Sections 4 and 4 in Appendix B of the application for an explanation of the base load operating scenario as well as startup/shutdown events.

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Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007B

Manufacturing or Processing Operations

___ Section B.1: Process Information
___ Section B.2: Materials and Fuel Informatic
___ Section B.3: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG.
___ Attach a flow diagram
___ Attach SDS

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AFS) #: 21- 167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: March 25, 2025

Section B.1: Process Information

Emission Unit #	Emission Unit Name	Describe Emission Unit	Process ID	Process Name	Manufacturer	Model No.	Proposed/Actual Date of Construction Commencement	Is the Process Continuous or Batch?	Number of Batches per 24 Hours *(if applicable)*	Hours per Batch *(if applicable)*
EQPT21, 63	Mechanical Draft Cooling Tower (10 Cells)		1	Gallons of Recirculating Water	na	na	06/2026	Continuous	na	na
EQPT22, 64	Turbine Circuit Breaker with 30 lb. SF6 circuit		1	SF6 Releases	na	na	06/2026	Continuous	na	na
EQPT23, 65	Lube Oil System with Demister Vents		1	Evaporative losses	na	na	06/2026	Continuous	na	na
EQPT26, 69	Natural Gas Piping Fugitives		1	Gas/Vapor Valves	na	na	06/2026	Continuous	na	na
EQPT26, 69	Natural Gas Piping Fugitives		2	Relief Valves	na	na	06/2026	Continuous	na	na
EQPT26, 69	Natural Gas Piping Fugitives		3	Flanges	na	na	06/2026	Continuous	na	na

Emission Unit #	Emission Unit Name	Describe Emission Unit	Process ID	Process Name	Manufacturer	Model No.	Proposed/Actual Date of Construction Commencement	Is the Process Continuous or Batch?	Number of Batches per 24 Hours *(if applicable)*	Hours per Batch *(if applicable)*
EQPT26, 69	Natural Gas Piping Fugitives		4	Vents	na	na	06/2026	Continuous	na	na
EQPT26, 69	Natural Gas Piping Fugitives		5	Compressors Components	na	na	06/2026	Continuous	na	na
EQPT26, 69	Natural Gas Piping Fugitives		6	Sampling Connections	na	na	06/2026	Continuous	na	na

Section B.2: Materials and Fuel Information

**Maximum yearly fuel usage rate only applies if applicant request operating restrictions through federally enforceable limitations.*

Emission Unit #	Emission Unit Name	Name of Raw Materials Input	Maximum Quantity of Each Raw Material Input		Total Process Weight Rate for Emission Unit *(tons/hr)*	Name of Finished Materials	Maximum Quantity of Each Finished Material Output		Fuel Type	Maximum Hourly Fuel Usage Rate		Maximum Yearly Fuel Usage Rate		Sulfur Content *(%)*	Ash Content *(%)*
				(Specify Units/hr)				*(Specify Units/hr)*			*(Specify Units)*		*(Specify Units)*		
EQPT21, 63	Mechanical Draft Cooling Tower (10 Cells)	Cooling Water	5.70	MMgal/hr	na	na	na	na	na	na	na	na	na	na	na
EQPT22, 64	Turbine Circuit Breaker with 30 lb. SF6 circuit	SF6	30.00	lb/ circuit	na	na	na	na	na	na	na	na	na	na	na
EQPT23, 65	Lube Oil System with Demister Vents	Lube Oil	0.02	gal/hr	na	na	na	na	na	na	na	na	na	na	na
EQPT26, 69	Natural Gas Piping Fugitives	Natural Gas	na	na	na	na	na	na	na	na	na	na	na	na	na

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Section B.3: Notes, Comments, and Explanations

While not process operations, the SF6-containing circuit breakers and natural gas pipeline equipment leak components are included on this DEP7007B form to comprehensively represent all new emissions sources on required DEP7007 series forms.

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Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
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DEP7007EE

Internal Combustion Engines

___ Section EE.1: General Information
___ Section EE.2: Operating Information
___ Section EE.3: Design Information
___ Section EE.4: Fuel Information
___ Section EE.5: Emission Factor Information
___ Section EE.6: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG

___ Attach EPA certification of the engine

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AFS) # 21- 167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: March 25, 2025

Section EE.1: General Information

Emission Unit #	Emission Unit Name	Control Device ID	Stack ID	Manufacturer	Model Number	Model Year	Date of Manufacture	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	Date Reconstructed/ Modified	List Applicable Regulations
COMB22, 61	2.18 MW Diesel Emergency Generator	na	S-61	Kohler/KD2000 or similar		TBD	TBD	6/22/2026	na	NSPS IIII, RICE MACT, 401 KAR 51:017
COMB23, 62	422 HP Diesel Driven Fire Pump	na	S-62	Clarke JW6H-UFAD80 or Similar		TBD	TBD	6/22/2026	na	NSPS IIII, RICE MACT, 401 KAR 51:017

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Section EE.2: Operating Information

Emission Unit #	Engine Purpose (Identify if Non-Emergency, Emergency,Fire/Water Pump, Black-start engine for combustion turbine, Engine Testing)	Hours Operated	Is this engine a rental? *(Yes/No)*	Rental Time Period *(hrs)*	Alternate Operating Scenarios (Describe any operating scenarios in which the engine may be used in a different configuration)
COMB22, 61	Emergency Electrical Generator Power	Estimated maximum of 500 hr/yr	No	na	na
COMB23, 62	Fire/Water Pump	Estimated maximum of 500 hr/yr	No	na	na

Section EE.3: Design Information

Emission Unit #	Engine Type (Identify all that apply: Commercial, Institutional, Stationary, Non-Road)	Ignition Type (Identify if either Compression or Spark Ignition)	Engine Family (Identify all that apply: 2-stroke, 4-stroke, Rich Burn, Lean Burn)	Maximum Engine Power *(bhp)*	Maximum Engine Speed *(rpm)*	Total Displacement *(L)*	Number of Cylinders
COMB22, 61	Stationary	Compression	4-stroke	2,923	1,800	62.0	12
COMB23, 62	Stationary	Compression	4-stroke	422	2,100	9	6

Section EE.4: Fuel Information

Emission Unit #	Identify if Primary, Secondary, or Tertiary Fuel	Fuel Type (Identify if Diesel, Gasoline, Natural Gas, Liquefied Petroleum Gas (LPG), Landfill/Digester Gas, or Other)	Fuel Grade	Percent Time Used *(%)*	Maximum Fuel Consumption	Heat Content	Sulfur Content *(%)*	SCC Code	SCC Units
COMB22, 61	Primary	Diesel	ULSFO	As needed	0.149 Mgal/hr	137.03 MMBtu/Mgal	0.0015%	20100102	1000 Gallons Distillate Oil (Diesel) Burned
COMB23, 62	Primary	Diesel	ULSFO	As needed	0.022 Mgal/hr	137.03 MMBtu/Mgal	0.0015%	20100102	1000 Gallons Distillate Oil (Diesel) Burned

Section EE.5: Emission Factor Information

Emission factors expressed here are based on the potential to emit.

Emission Unit #	Fuel	Pollutant	Emission Factor	Emission Factor Units	Source of Emission Factor
COMB22, 61	Diesel	NOX	201.137	lb/Mgal	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW; See Section 7.2 in Appendix B
COMB22, 61	Diesel	CO	111.350	lb/Mgal	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I; See Section 7.2 in Appendix B
COMB22, 61	Diesel	VOC	5.375	lb/Mgal	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW; See Section 7.2 in Appendix B
COMB22, 61	Diesel	PT	6.363	lb/Mgal	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I; See Section 7.2 in Appendix B
COMB22, 61	Diesel	PM10	6.363	lb/Mgal	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I; See Section 7.2 in Appendix B
COMB22, 61	Diesel	PM2.5	6.363	lb/Mgal	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I; See Section 7.2 in Appendix B
COMB22, 61	Diesel	SO2	0.208	lb/Mgal	AP-42 Table 3.4-1
COMB22, 61	Diesel	CO2	22,501	lb/Mgal	40 CFR 98, Subpart C, Table C-1
COMB22, 61	Diesel	CH4	0.913	lb/Mgal	40 CFR 98, Subpart C, Table C-2
COMB22, 61	Diesel	N2O	0.183	lb/Mgal	40 CFR 98, Subpart C, Table C-2

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Emission Unit #	Fuel	Pollutant	Emission Factor	Emission Factor Units	Source of Emission Factor
COMB23, 62	Diesel	NOX	159.678	lb/Mgal	= 4 g/kW-hr * 0.925 / 1.341 hp/kW; See Section 8.2 in Appendix B
COMB23, 62	Diesel	CO	112.208	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII) ; See Section 8.2 in Appendix B
COMB23, 62	Diesel	VOC	9.657	lb/Mgal	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW; See Section 8.2 in Appendix B
COMB23, 62	Diesel	PT	6.474	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII) ; See Section 8.2 in Appendix B
COMB23, 62	Diesel	PM10	6.474	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII) ; See Section 8.2 in Appendix B
COMB23, 62	Diesel	PM2.5	6.474	lb/Mgal	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII) ; See Section 8.2 in Appendix B
COMB23, 62	Diesel	SO2	0.208	lb/Mgal	40 CFR 98, Subpart C, Table C-1
COMB23, 62	Diesel	CO2	22,343	lb/Mgal	40 CFR 98, Subpart C, Table C-2
COMB23, 62	Diesel	CH4	0.906	lb/Mgal	40 CFR 98, Subpart C, Table C-2
COMB23, 62	Diesel	N2O	0.181	lb/Mgal	40 CFR 98, Subpart A

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Section EE.6: Notes, Comments, and Explanations

EE.2 Form - In a memo from EPA Air Quality and planning Standards Director John S. Seitz to the region directors of Air and Radiation, “Calculating Potential to Emit (PTE) for Emergency Generators”, dated September 6, 1995, EPA formalized its position that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.

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Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
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DEP7007J

Volatile Liquid Storage

___ Section J.1: General Information
___ Section J.2: Tank Description
___ Section J.3: Gasoline Plants and Termi
___ Section J.4: Loading Rack(s)
___ Section J.5: Equipment Leaks
___ Section J.6: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI, DEP7007N, DEP7007V, and DEP7007GG.
___ SDS attached

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AFS): 21- 167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: March 25, 2025

Section J.1: General Information

Emission Unit #	Emission Unit Name	Emission Unit Description	Proposed/Actual Date of Construction Commencement *(MM/YYYY)*	Date of modification/ reconstruction	Control Device ID	Stack ID
EQPT24, 66	Diesel Storage Tank for Generator (3,733 gal)		6/22/2026	na	na	S-66
EQPT25, 67	Diesel Storage Tank for Firewater Pump (300 gal)		6/22/2026	na	na	S-67
EQPT27, 70	93% Sulfuric Acid Tank		6/22/2026	na	na	S-70

Section J.2: Tank Description

Emission Point #: EQPT24, 66

Emission Point Name: Diesel Storage Tank for Generator (3,733 gal)

Tank ID#: TBD

Date Installed: 6/22/2026

List Applicable Regulations: 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)*		Vapor Pressure *(psia)*	
					Minimum	Maximum	Minimum	Maximum
ULSFO	74,500	7.1	~188	100% No. 2 Diesel Fuel	Average Bulk Storage Temp = 59.00 deg.F		Tank Stock True Vapor Pressure = 0.0070 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 3,733 **Height/ Length:** *(ft)* 13.65 **Shell Diameter:** *(ft)* 6.82 **Tank Turnovers per Year:** 19.96

Tank Orientation: ☑ Horizontal ☐ Vertical If Vertical, provide Maximum Liquid Height: *(ft)* na Average Liquid Height: *(ft)* na

Shell Color/Shade: ☐ Red ☐ White ☑ Light Gra ☐ Medium Gray ☐ Aluminum Specula Aluminum Diffuse Other: _____

Roof Color: ☐ Slack ☐ White ☑ Light Gra ☐ Medium Gray ☐ Aluminum Specula Aluminum Diffuse Other: _____

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type: ☐ Dome ☑ Flat ☐ Cone **Dome/Cone Height:** na ft **Average Vapor Space Height:** Unknown ft

Is Tank Undergroun ☐ Yes ☑ No **Roof Condition:** ☑ Good ☐ Poor **Vacuum Setting:** _____ psig

Is Tank Heated?: ☐ Yes ☑ No **Shell Condition:** ☑ Good ☐ Poor **Pressure Setting:** _____ psig

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal Shoe Mounted

☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined **External Shell Conditio** Good Poor

Roof Paint Condition: ☐ Good ☐ Poor **Self Supporting Roof?** Yes No

Number of Support Columns: _____ **Effective Column Diameter:** _____ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Sean _____ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well Vacuum Breaker

☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:
- ☐ Vapor Mounted Primary
- ☐ Vapor Mounted Primary Rim Secondary Seal
- Vapor Mounted Prmary with Weather Shield
- ☐ Liquid Mounted Primary
- ☐ Liquid Mounted Primary Rim Secondary Seal
- Liquid Mounted Primary with Weather Shield
- ☐ Shoe Mounted Primary
- ☐ Shoe Mounted Primary Rim Secondary Seal
- Shoe Mounted Primary Shoe Secondary

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

Tank Type: ☐ Riveted ☐ Welded

Roof Type: ☐ Pontoon Roof ☐ Double Deck Roof

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:
- ☐ Access Hatch
- ☐ Gauge Hatch
- ☐ Sample Well
- Roof Leg
- Vacuum Breaker
- ☐ Guide Pole
- ☐ Gauge Float
- ☐ Roof Drain
- Rim Vent
- Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	ULSFO	Breathing Losses	4.186	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	ULSFO	Working Losses	0.001	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Section J.2: Tank Description

Emission Point #: EQPT25, 67

Emission Point Name: Diesel Storage Tank for Firewater Pump (300 gal)

Tank ID#: TBD

Date Installed: 6/22/2026

List Applicable Regulations: 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)*		Vapor Pressure *(psia)*	
					Minimum	Maximum	Minimum	Maximum
ULSFO	10,779	7.1	~188	100% No. 2 Diesel Fuel	Average Bulk Storage Temp = 59.00 deg.F		Tank Stock True Vapor Pressure = 0.0070 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 300 **Height/ Length:** *(ft)* 5.89 **Shell Diameter:** *(ft)* 2.94 **Tank Turnovers per Year:** 35.93

Tank Orientation: ☑ Horizontal ☐ Vertical If Vertical, provide Maximum Liquid Height: *(ft)* na Average Liquid Height: *(ft)* na

Shell Color/Shade: ☐ Red ☐ White ☑ Light Gra ☐ Medium Gray ☐ Aluminum Specula Aluminum Diffuse Other: _____

Roof Color: ☐ Slack ☐ White ☑ Light Gra ☐ Medium Gray ☐ Aluminum Specula Aluminum Diffuse Other: _____

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type: ☐ Dome ☑ Flat ☐ Cone **Dome/Cone Height:** na ft **Average Vapor Space Height:** Unknown ft

Is Tank Undergroun ☐ Yes ☑ No **Roof Condition:** ☑ Good ☐ Poor **Vacuum Setting:** _____ psig

Is Tank Heated?: ☐ Yes ☑ No **Shell Condition:** ☑ Good ☐ Poor **Pressure Setting:** _____ psig

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal Shoe Mounted

☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined **External Shell Conditio** Good Poor

Roof Paint Condition: ☐ Good ☐ Poor **Self Supporting Roof?** Yes No

Number of Support Columns: _____ **Effective Column Diameter:** _____ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Sean _____ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well Vacuum Breaker

☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:
- ☐ Vapor Mounted Primary
- ☐ Vapor Mounted Primary Rim Secondary Seal
- Vapor Mounted Prmary with Weather Shield
- ☐ Liquid Mounted Primary
- ☐ Liquid Mounted Primary Rim Secondary Seal
- Liquid Mounted Primary with Weather Shield
- ☐ Shoe Mounted Primary
- ☐ Shoe Mounted Primary Rim Secondary Seal
- Shoe Mounted Primary Shoe Secondary

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

Tank Type: ☐ Riveted ☐ Welded

Roof Type: ☐ Pontoon Roof ☐ Double Deck Roof

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:
- ☐ Access Hatch
- ☐ Gauge Hatch
- ☐ Sample Well
- Roof Leg
- Vacuum Breaker
- ☐ Guide Pole
- ☐ Gauge Float
- ☐ Roof Drain
- Rim Vent
- Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	ULSFO	Breathing Losses	0.257	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	ULSFO	Working Losses	0.001	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Section J.2: Tank Description

Emission Point #: EQPT27, 70

Emission Point Name: 93% Sulfuric Acid Tank

Tank ID#: TBD

Date Installed: 6/22/2026

List Applicable Regulations: 401 KAR 51:017

J.2A: Stored Liquid Data:

Single or Multi-Component Liquid Name(s)	Maximum Annual Throughput *(gal/yr)*	Liquid Density *(lb/gal)*	Molecular Weight of Single or Multi-Component Liquid	Percent Composition of Multi-Component Liquid(s)	Temperature *(°F)*		Vapor Pressure *(psia)*	
					Minimum	Maximum	Minimum	Maximum
H2SO4	146,400	15.4	98.08 (H_2SO_4)	93% H_2SO_4 7% Water	Average Bulk Storage Temp = 56.51 deg.F		Tank Stock True Vapor Pressure = 1.16E-05 psia	

J.2B: Tank Data:

Tank Capacity: *(gallons)* 12,200 **Height/ Length:** *(ft)* 22.00 **Shell Diameter:** *(ft)* 10.00 **Tank Turnovers per Year:** 12.00

Tank Orientation: ☑ Horizontal ☐ Vertical If Vertical, provide Maximum Liquid Height: *(ft)* na Average Liquid Height: *(ft)* na

Shell Color/Shade: ☐ Red ☐ White ☑ Light Gra ☐ Medium Gray ☐ Aluminum Specula Aluminum Diffuse Other: _____

Roof Color: ☐ Slack ☐ White ☑ Light Gra ☐ Medium Gray ☐ Aluminum Specula Aluminum Diffuse Other: _____

Tank Type: ☑ Fixed Roof ☐ Internal Floating Roof ☐ External Floating Roof Pressure Tank

J.2C: For Fixed Roof Tanks:

Roof Type: ☐ Dome ☑ Flat ☐ Cone **Dome/Cone Height:** na ft **Average Vapor Space Height:** Unknown ft

Is Tank Undergroun ☐ Yes ☑ No **Roof Condition:** ☑ Good ☐ Poor **Vacuum Setting:** _____ psig

Is Tank Heated?: ☐ Yes ☑ No **Shell Condition:** ☑ Good ☐ Poor **Pressure Setting:** _____ psig

J.2D: For All Internal Floating Roof Tanks:

Rim Seal Description ☐ Vapor Mounted Primary ☐ Vapor Mounted Primary plus Secondary Seal Shoe Mounted

☐ Liquid Mounted Primary ☐ Liquid Mounted Primary plus Secondary Seal Shoe Mounted plus Secondary Seal

Secondary Seal: ☐ Rim Mounted ☐ Shoe Mounted ☐ None

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined **External Shell Conditio** Good Poor

Roof Paint Condition: ☐ Good ☐ Poor **Self Supporting Roof?** Yes No

Number of Support Columns: _____ **Effective Column Diameter:** _____ ft

J.2E: Deck Data for Internal Floating Roofs:

Length of Deck Sean _____ ft

Deck Type: ☐ Bolted ☐ Welded

Type of Deck Fitting: ☐ Access Hatch ☐ Ladder Well ☐ Sample Pipe ☐ Sample Well Vacuum Breaker

☐ Column Well ☐ Roof Leg ☐ Hanger Well ☐ Stub Drain Automatic Gauge Float Well

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover or fabric seal, adjustable or fixed roof leg/hanger well and number)

J.2F: For All External Floating Roof Tanks:

Rim Seal Description:
- ☐ Vapor Mounted Primary
- ☐ Vapor Mounted Primary Rim Secondary Seal
- Vapor Mounted Prmary with Weather Shield
- ☐ Liquid Mounted Primary
- ☐ Liquid Mounted Primary Rim Secondary Seal
- Liquid Mounted Primary with Weather Shield
- ☐ Shoe Mounted Primary
- ☐ Shoe Mounted Primary Rim Secondary Seal
- Shoe Mounted Primary Shoe Secondary

Internal Shell Condition: ☐ Light Rust ☐ Dense Rust ☐ Gunite-lined

Tank Type: ☐ Riveted ☐ Welded

Roof Type: ☐ Pontoon Roof ☐ Double Deck Roof

J.2G: Deck Data for External Floating Roof Tanks:

Type of Deck Fitting:
- ☐ Access Hatch
- ☐ Gauge Hatch
- ☐ Sample Well
- Roof Leg
- Vacuum Breaker
- ☐ Guide Pole
- ☐ Gauge Float
- ☐ Roof Drain
- Rim Vent
- Other

Design of each deck fitting:
(diameter sizes, bolted or gasket covers, sliding cover, unslotted or slotted guide pole well, adjusted or fixed roof leg and number of each design)

J.2H: Emissions Data:

Attach SDS/Composition Analysis for Each Component Listed

Process ID	Component Name	Process Name (e.g. Breathing, Working, Cleaning, Flashing Loss(es))	Lost Emissions *(lb/1000 gal)*	Frequency of Occurrence	Determination Methodology for Each Type of Loss*
1	H2SO4	Breathing Losses	6.60E-05	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1
2	H2SO4	Working Losses	4.37E-07	Annual	TankESP analysis using methodology presented in AP-42 Section 7.1

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

Section J.6: Notes, Comments, and Explanations

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007HH

Haul Roads

_____ Section HH.1: Haul Roads
_____ Section HH.2: Yard Area
_____ Section HH.3: Notes, Comments, and Explanation

Additional Documentation

___ Complete DEP7007AI, DEP7007N and DEP7007V

___ SDS for dust suppressant

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)

KY EIS (AFS) #: 21- 167-00001

Permit #: V-17-030 R1

Agency Interest (AI) ID: 3148

Date: March 25, 2025

Section HH.1: Haul Roads

HH.1A Unpaved Haul Roads:

Average Number of Days in a Year with 0.01 inches of Precipitation (P): na Days

Mean Vehicle Weight (W): na Tons

Surface Material Silt Content (s): na %

Haul Road Length: na Miles

Maximum Vehicle Miles Traveled in a Year: na Miles

Describe the dust control method for unpaved haul road(s):
(If dust control suppressants will be utilized, attach the approved Safety Data Sheet(s), as applicable.)

na

Emission factor:

na

HH.1B Paved Haul Roads:

Average Number of Days in a Year with 0.01 inches of Precipitation (P): 132 Days

Mean Vehicle Weight (W): 12.0-31.4 Tons

Road Surface Silt Loading (sL): 0.6 (G/M^2)

Haul Road Length: 2.08 Miles

Maximum Vehicle Miles Traveled in a Year: 659 Miles

Describe the dust control method for paved haul road(s):
(If dust control suppressants will be utilized, attach the approved Safety Data Sheet(s), as applicable.)

Will follow the existing dust control plan, which includes watering, sweeping, or other approriate means.

Section HH.2: Yard Area (Aggregate Handling And Storage Piles):

Average Number of Days in a Year with 0.01 inches of Precipitation (P): na Days

Mean Wind Speed (U): na MPH

Material Moisture Content (M): na %

Describe the dust control method for yard area:
(If dust control suppressants will be utilized, attach the approved Safety Data Sheet(s), as applicable.)

na

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Section HH.3: Notes, Comments, and Explanations

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007N

Source Emissions Profile

__ Section N.1: Emission Summary
__ Section N.2: Stack Information
__ Section N.3: Fugitive Information
__ Section N.4: Notes, Comments, and Explanations

Additional Documentation

__ Complete DEP7007AI

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AFS) #: 21- 167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: March 25, 2025

N.1: Emission Summary

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
58	Unit 12 Gas Turbine with HRSG and DB															
		1	Natural Gas Firing in GT & DB					SCC Code: 20100201			SCC Units: Million Cubic Feet Natural Gas Burned					
				SCR	C34	S-58	4.297	NOX	79.219	KU Requirement; See Section 4.3 in App B	na	90%	340.4	34.0	1,490.9	149.1
				Oxidation Catalyst	C35	S-58	4.297	CO	48.232	KU Requirement; See Section 4.3 in App B	na	90%	207.2	20.7	907.7	90.8
				Oxidation Catalyst	C35	S-58	4.297	VOC	5.525	KU Requirement; See Section 4.3 in App B	na	50%	23.74	11.87	104.0	52.0
				NA	NA	S-58	4.297	PM	5.256	Vendor Estimate; See Section 4.3 in App B	na	na	22.6	22.6	98.9	98.9
				NA	NA	S-58	4.297	PM10	5.256	Vendor Estimate; See Section 4.3 in App B	na	na	22.6	22.6	98.9	98.9
				NA	NA	S-58	4.297	PM2.5	5.256	Vendor Estimate; See Section 4.3 in App B	na	na	22.6	22.6	98.9	98.9
				NA	NA	S-58	4.297	SO2	1.427	Pipeline spec conversion; See Section 4.3 in App B	na	na	6.13	6.13	26.9	26.9
				NA	NA	S-58	4.297	H2SO4	1.259	Pipeline spec conversion; See Section 4.3 in App B	na	na	5.41	5.41	23.69	23.69
				NA	NA	S-58	4.297	NH3	7.332	KU Requirement; See Section 4.3 in App B	na	na	31.5	31.5	138.0	138.0

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
				NA	NA	S-58	4.297	CO2	120,019	40 CFR 98, Table C-1; See Section 4.3 in App B	na	na	515,709	515,709	2,258,806	2,258,806
				NA	NA	S-58	4.297	CH4	24.881	40 CFR 98, Table C-2; See Section 4.3 in App B	na	na	106.9	106.9	468.3	468.3
				NA	NA	S-58	4.297	N2O	3.619	40 CFR 98, Table C-2; See Section 4.3 in App B	na	na	15.6	15.6	68.1	68.1
				NA	NA	S-58	4.297	CO2e	121,674	40 CFR 98 Subpart A; See Section 4.3 in App B	na	na	522,824	522,824	2,289,968	2,289,968
				Oxidation Catalyst	C35	S-58	4.297	1,3-Butadiene	3.97E-04	AP-42 Table 3.1; See Section 4.3 in App B	na	50.0%	1.70E-03	8.52E-04	7.47E-03	3.73E-03
				Oxidation Catalyst	C35	S-58	4.297	Acetaldehyde	0.3248	AP-42 Table 3.1 & 3-4 of BID; See Section 4.3 in App B	na	50.0%	1.396	0.698	6.113	3.057
				Oxidation Catalyst	C35	S-58	4.297	Acrolein	0.0059	AP-42 Table 3.1 & 3-4 of BID; See Section 4.3 in App B	na	43.4%	0.025	0.014	0.111	0.063
				Oxidation Catalyst	C35	S-58	4.297	Benzene	0.0113	AP-42 Table 3.1 & 3-4 of BID and AP-42 Table 1.4-3; See Section 4.3 in App B	na	72.4%	0.048	0.013	0.212	0.058
				Oxidation Catalyst	C35	S-58	4.297	Dichlorobenzene	1.14E-04	AP-42 Table 1.4-3; See Section 4.3 in App B	na	50.0%	4.92E-04	2.46E-04	2.15E-03	1.08E-03
				Oxidation Catalyst	C35	S-58	4.297	Ethylbenzene	0.0295	AP-42 Table 3.1; See Section 4.3 in App B	na	50.0%	0.127	0.063	0.556	0.278
				Oxidation Catalyst	C35	S-58	4.297	Formaldehyde	0.6552	KU Requirement; See Section 4.3 in App B	na	67.5%	2.815	0.916	12.330	4.012
				Oxidation Catalyst	C35	S-58	4.297	Naphthalene	1.26E-03	AP-42 Table 3.1 and AP-42 Table 1.4-3; See Section 4.3 in App B	na	50.0%	5.40E-03	2.70E-03	2.37E-02	1.18E-02
				Oxidation Catalyst	C35	S-58	4.297	Hexane	0.1716	AP-42 Table 1.4-3; See Section 4.3 in App B	na	50.0%	0.737	0.369	3.230	1.615
				Oxidation Catalyst	C35	S-58	4.297	PAH	2.03E-03	AP-42 Table 3.1; See Section 4.3 in App B	na	50.0%	8.72E-03	4.36E-03	3.82E-02	1.91E-02
				Oxidation Catalyst	C35	S-58	4.297	Propylene Oxide	0.0268	AP-42 Table 3.1; See Section 4.3 in App B	na	50.0%	0.115	0.057	0.50	0.25
				Oxidation Catalyst	C35	S-58	4.297	Toluene	0.1203	AP-42 Table 3.1 and AP-42 Table 1.4-3; See Section 4.3 in App B	na	50.0%	0.517	0.258	2.26	1.13
				Oxidation Catalyst	C35	S-58	4.297	Xylenes	0.0591	AP-42 Table 3.1; See Section 4.3 in App B	na	50.0%	0.254	0.127	1.11	0.56
				NA	NA	S-58	4.297	Arsenic	1.91E-05	AP-42 Table 1.4-4; See Section 4.3 in App B	na	0.0%	8.19E-05	8.19E-05	3.59E-04	3.59E-04

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
				NA	NA	S-58	4.297	Beryllium	1.14E-06	||	na	0.0%	4.92E-06	4.92E-06	2.15E-05	2.15E-05
				NA	NA	S-58	4.297	Cadmium	1.05E-04	||	na	0.0%	4.51E-04	4.51E-04	1.97E-03	1.97E-03
				NA	NA	S-58	4.297	Chromium	1.33E-04	||	na	0.0%	5.74E-04	5.74E-04	2.51E-03	2.51E-03
				NA	NA	S-58	4.297	Cobalt	8.01E-06	||	na	0.0%	3.44E-05	3.44E-05	1.51E-04	1.51E-04
				NA	NA	S-58	4.297	Lead	4.77E-05	||	na	0.0%	2.05E-04	2.05E-04	8.97E-04	8.97E-04
				NA	NA	S-58	4.297	Manganese	3.62E-05	||	na	0.0%	1.56E-04	1.56E-04	6.82E-04	6.82E-04
				NA	NA	S-58	4.297	Mercury	2.48E-05	||	na	0.0%	1.07E-04	1.07E-04	4.67E-04	4.67E-04
				NA	NA	S-58	4.297	Nickel	2.00E-04	||	na	0.0%	8.60E-04	8.60E-04	3.77E-03	3.77E-03
				NA	NA	S-58	4.297	Selenium	2.29E-06	||	na	0.0%	9.83E-06	9.83E-06	4.31E-05	4.31E-05
				NA	NA	S-58	4.297	Total HAP	1.4088	||	na	58.3%	6.053	2.527	26.513	11.068
Process ID 1, should only be used when the GT is in "fired" mode.																
		2	Natural Gas Firing in GT					SCC Code: 20100201					SCC Units: Million Cubic Feet Natural Gas Burned			
				SCR	C34	S-58	3.770	NOX	84.364	KU Requirement; See Section 4.5 in App B	na	90%	318.0	31.8	1,392.9	139.3
				Oxidation Catalyst	C35	S-58	3.770	CO	51.364	KU Requirement; See Section 4.5 in App B	na	90%	193.6	19.4	848.1	84.8
				Oxidation Catalyst	C35	S-58	3.770	VOC	2.942	KU Requirement; See Section 4.5 in App B	na	50%	11.09	5.55	48.6	24.3
				NA	NA	S-58	3.770	PM	4.763	Vendor Estimate; See Section 4.5 in App B	na	na	18.0	18.0	78.6	78.6
				NA	NA	S-58	3.770	PM10	4.763	Vendor Estimate; See Section 4.5 in App B	na	na	18.0	18.0	78.6	78.6
				NA	NA	S-58	3.770	PM2.5	4.763	Vendor Estimate; See Section 4.5 in App B	na	na	18.0	18.0	78.6	78.6
				NA	NA	S-58	3.770	SO2	1.427	Pipeline spec conversion; See Section 4.5 in App B	na	na	5.38	5.38	23.6	23.6

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity *(SCC Units/hour)*	Pollutant	Uncontrolled Emission Factor *(lb/SCC Units)*	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency *(%)*	Control Efficiency *(%)*	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential *(lb/hr)*	Controlled Potential *(lb/hr)*	Uncontrolled Potential *(tons/yr)*	Controlled Potential *(tons/yr)*
				NA	NA	S-58	3.770	H2SO4	1.261	Pipeline spec conversion; See Section 4.5 in App B	na	na	4.75	4.75	20.82	20.82
				NA	NA	S-58	3.770	NH3	7.808	KU Requirement; See Section 4.5 in App B	na	na	29.4	29.4	128.9	128.9
				NA	NA	S-58	3.770	CO2	120,019	40 CFR 98, Table C-1; See Section 4.5 in App B	na	na	452,430	452,430	1,981,641	1,981,641
				NA	NA	S-58	3.770	CH4	0.024	40 CFR 98, Table C-2; See Section 4.5 in App B	na	na	0.1	0.1	0.4	0.4
				NA	NA	S-58	3.770	N2O	0.004	40 CFR 98, Table C-2; See Section 4.5 in App B	na	na	0.0	0.0	0.1	0.1
				NA	NA	S-58	3.770	CO2e	121674.428	40 CFR 98 Subpart A; See Section 4.5 in App B	na	na	458,671.114	458,671.114	2,008,979.48	2,008,979.48
				Oxidation Catalyst	C35	S-58	3.770	1,3-Butadiene	4.39E-04	AP-42 Table 3.1; See Section 4.5 in App B	na	50.0%	1.65E-03	8.27E-04	7.24E-03	3.62E-03
				Oxidation Catalyst	C35	S-58	3.770	Acetaldehyde	0.3590	AP-42 Table 3.1 & 3-4 of BID; See Section 4.5 in App B	na	50.0%	1.353	0.677	5.928	2.964
				Oxidation Catalyst	C35	S-58	3.770	Acrolein	0.0065	AP-42 Table 3.1 & 3-4 of BID; See Section 4.5 in App B	na	43.4%	0.025	0.014	0.108	0.061
				Oxidation Catalyst	C35	S-58	3.770	Benzene	0.0122	AP-42 Table 3.1 & 3-4 of BID; See Section 4.5 in App B	na	72.8%	0.046	0.013	0.202	0.055
				Oxidation Catalyst	C35	S-58	3.770	Ethylbenzene	0.0326	AP-42 Table 3.1; See Section 4.5 in App B	na	50.0%	0.123	0.062	0.539	0.269
				Oxidation Catalyst	C35	S-58	3.770	Formaldehyde	0.7242	KU Requirement; See Section 4.5 in App B	na	65.4%	2.730	0.945	11.957	4.139
				Oxidation Catalyst	C35	S-58	3.770	Naphthalene	0.0013	AP-42 Table 3.1; See Section 4.5 in App B	na	50.0%	0.005	0.002	0.022	0.011
				Oxidation Catalyst	C35	S-58	3.770	PAH	0.0022	AP-42 Table 3.1; See Section 4.5 in App B	na	50.0%	0.008	0.004	0.037	0.019
				Oxidation Catalyst	C35	S-58	3.770	Propylene Oxide	0.0296	AP-42 Table 3.1; See Section 4.5 in App B	na	50.0%	0.112	0.056	0.488	0.244
				Oxidation Catalyst	C35	S-58	3.770	Toluene	0.1326	AP-42 Table 3.1; See Section 4.5 in App B	na	50.0%	0.500	0.250	2.189	1.095
				Oxidation Catalyst	C35	S-58	3.770	Xylenes	0.0653	AP-42 Table 3.1; See Section 4.5 in App B	na	50.0%	0.246	0.123	1.078	0.539
				Oxidation Catalyst	C35	S-58	3.770	Total HAP	1.3661	Sum; See Section 4.5 in App B	na	58.3%	5.150	2.146	22.556	9.400

Process ID 2, should only be used when the GT is in "un-fired" mode.

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
		3	Cold Startup Events					SCC Code: 39999993			SCC Units: Each Parts Processed					
				na	na	S-58	1	NOX	420	GE Vendor Data; See Section 4.7 in App B	na	na	420	420	2.10	2.10
				na	na	S-58	1	CO	758	GE Vendor Data; See Section 4.7 in App B	na	na	758	758	3.79	3.79
				na	na	S-58	1	VOC	135	GE Vendor Data; See Section 4.7 in App B	na	na	135	135	0.68	0.68
				na	na	S-58	1	PM	32	GE Vendor Data; See Section 4.7 in App B	na	na	32	32	0.16	0.16
				na	na	S-58	1	PM10	32	GE Vendor Data; See Section 4.7 in App B	na	na	32	32	0.16	0.16
				na	na	S-58	1	PM2.5	32	GE Vendor Data; See Section 4.7 in App B	na	na	32	32	0.16	0.16
				na	na	S-58	1	SO2	9.5	Extrapolated Data; See Section 4.7 in App B	na	na	9.533	9.533	0.048	0.048
				na	na	S-58	1	H2SO4	8.5	Extrapolated Data; See Section 4.7 in App B	na	na	8.474	8.474	0.042	0.042
				na	na	S-58	1	CO2	291,390	Extrapolated Data; See Section 4.7 in App B	na	na	291,390	291,390	1,457	1,457
				na	na	S-58	1	CO2e	291,390	GHGs Assume 100% CO2	na	na	291,390	291,390	1,457	1,457
* The hourly emissions represented in this form for CS, WS, HS, and SD are normalized to the maximum number of events per year. Within the dispersion modeling, the maximum hourly emission rate considers shortest duration before the minimum emissions compliance load (MECL) is reached. For example, 420 lb/event is expected during a CS and the MECL is 1.22 hrs. As a result, the modeled emission rate is 345.21 lb/hr for NOx.																
		4	Warm Startup Events					SCC Code: 39999993			SCC Units: Each Parts Processed					
				na	na	S-58	1	NOX	260	GE Vendor Data; See Section 4.7 in App B	na	na	260	260	6.50	6.50
				na	na	S-58	1	CO	476	GE Vendor Data; See Section 4.7 in App B	na	na	476	476	11.90	11.90
				na	na	S-58	1	VOC	121	GE Vendor Data; See Section 4.7 in App B	na	na	121	121	3.03	3.03
				na	na	S-58	1	PM	27	GE Vendor Data; See Section 4.7 in App B	na	na	27	27	0.68	0.68
				na	na	S-58	1	PM10	27	GE Vendor Data; See Section 4.7 in App B	na	na	27	27	0.68	0.68
				na	na	S-58	1	PM2.5	27	GE Vendor Data; See Section 4.7 in App B	na	na	27	27	0.68	0.68

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
				na	na	S-58	1	SO2	8.0	Extrapolated Data; See Section 4.7 in App B	na	na	8.043	8.043	0.201	0.201
				na	na	S-58	1	H2SO4	7.1	Extrapolated Data; See Section 4.7 in App B	na	na	7.150	7.150	0.179	0.179
				na	na	S-58	1	CO2	249,980	Extrapolated Data; See Section 4.7 in App B	na	na	249,980	249,980	6,249	6,249
				na	na	S-58	1	CO2e	249,980	GHGs Assume 100% CO2	na	na	249,980	249,980	6,249	6,249
		5	Hot Startup Events					SCC Code: 39999993			SCC Units: Each Parts Processed					
				na	na	S-58	1	NOX	135	GE Vendor Data; See Section 4.7 in App B	na	na	135	135	8.44	8.44
				na	na	S-58	1	CO	303	GE Vendor Data; See Section 4.7 in App B	na	na	303	303	18.94	18.94
				na	na	S-58	1	VOC	91	GE Vendor Data; See Section 4.7 in App B	na	na	91	91	5.69	5.69
				na	na	S-58	1	PM	15	GE Vendor Data; See Section 4.7 in App B	na	na	15	15	0.94	0.94
				na	na	S-58	1	PM10	15	GE Vendor Data; See Section 4.7 in App B	na	na	15	15	0.94	0.94
				na	na	S-58	1	PM2.5	15	GE Vendor Data; See Section 4.7 in App B	na	na	15	15	0.94	0.94
				na	na	S-58	1	SO2	4.5	Extrapolated Data; See Section 4.7 in App B	na	na	4.469	4.469	0.279	0.279
				na	na	S-58	1	H2SO4	4.0	Extrapolated Data; See Section 4.7 in App B	na	na	3.972	3.972	0.248	0.248
				na	na	S-58	1	CO2	106,800	Extrapolated Data; See Section 4.7 in App B	na	na	106,800	106,800	6,675	6,675
				na	na	S-58	1	CO2e	106,800	GHGs Assume 100% CO2	na	na	106,800	106,800	6,675	6,675
		6	Shutdown Events					SCC Code: 39999993			SCC Units: Each Parts Processed					
				na	na	S-58	1	NOX	78	GE Vendor Data; See Section 4.7 in App B	na	na	78	78	7.22	7.22
				na	na	S-58	1	CO	244	GE Vendor Data; See Section 4.7 in App B	na	na	244	244	22.57	22.57
				na	na	S-58	1	VOC	118	GE Vendor Data; See Section 4.7 in App B	na	na	118	118	10.92	10.92

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
				na	na	S-58	1	PM	5	GE Vendor Data; See Section 4.7 in App B	na	na	5	5	0.46	0.46
				na	na	S-58	1	PM10	5	GE Vendor Data; See Section 4.7 in App B	na	na	5	5	0.46	0.46
				na	na	S-58	1	PM2.5	5	GE Vendor Data; See Section 4.7 in App B	na	na	5	5	0.46	0.46
				na	na	S-58	1	SO2	1.5	Extrapolated Data; See Section 4.7 in App B	na	na	1.490	1.490	0.138	0.138
				na	na	S-58	1	H2SO4	1.3	Extrapolated Data; See Section 4.7 in App B	na	na	1.324	1.324	0.122	0.122
				na	na	S-58	1	CO2	23,571	Extrapolated Data; See Section 4.7 in App B	na	na	23,571	23,571	2,180	2,180
				na	na	S-58	1	CO2e	23,571	GHGs Assume 100% CO2	na	na	23,571	23,571	2,180	2,180
59	Auxiliary Steam Boiler															
		1	Natural Gas Combustion w/ LNB & FGR					SCC Code: 10200602					SCC Units: Million Cubic Feet Natural Gas Burned			
				NA	na	S-59	0.0907	NOX	38.339	KU Requirement; See Section 5.3 in App B	na	na	3.478	3.478	6.96	6.96
				NA	na	S-59	0.0907	CO	38.900	KU Requirement; See Section 5.3 in App B	na	na	3.529	3.529	7.06	7.06
				NA	na	S-59	0.0907	VOC	5.5	AP-42 Table 1.4-2; See Section 5.3 in App B	na	na	0.499	0.499	1.00	1.00
				NA	na	S-59	0.0907	PM	1.90	AP-42 Table 1.4-2; See Section 5.3 in App B	na	na	0.172	0.172	0.34	0.34
				NA	na	S-59	0.0907	PM10	7.14	AP-42 Table 1.4-2 + KU Requirement; See Section 5.3 in App B	na	na	0.648	0.648	1.30	1.30
				NA	na	S-59	0.0907	PM2.5	7.14	KU Requirement; See Section 5.3 in App B	na	na	0.648	0.648	1.30	1.30
				NA	na	S-59	0.0907	SO2	1.43	Pipeline spec conversion; See Section 5.3 in App B	na	na	0.129	0.129	0.26	0.26
				NA	na	S-59	0.0907	H2SO4	0.109	Pipeline spec conversion; See Section 5.3 in App B	na	na	0.010	0.010	0.02	0.02
				NA	na	S-59	0.0907	Lead	0.0005	AP-42, Table 1.4-2; See Section 5.3 in App B	na	na	4.54E-05	4.54E-05	9.07E-05	9.07E-05
				NA	na	S-59	0.0907	CO2	123,177	40 CFR 98, Table C-1; See Section 5.3 in App B	na	na	11,173	11,173	22,347	22,347

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity *(SCC Units/hour)*	Pollutant	Uncontrolled Emission Factor *(lb/SCC Units)*	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency *(%)*	Control Efficiency *(%)*	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential *(lb/hr)*	Controlled Potential *(lb/hr)*	Uncontrolled Potential *(tons/yr)*	Controlled Potential *(tons/yr)*
				NA	na	S-59	0.0907	CH4	2.32	40 CFR 98, Table C-2; See Section 5.3 in App B	na	na	0.211	0.211	0.42	0.42
				NA	na	S-59	0.0907	N2O	0.232	40 CFR 98, Table C-2; See Section 5.3 in App B	na	na	0.021	0.021	0.04	0.04
				NA	na	S-59	0.0907	CO2e	123,304	40 CFR 98, Subpart A; See Section 5.3 in App B	na	na	11,185	11,185	22,370	22,370
				NA	na	S-59	0.0907	Benzene	0.0021	AP-42, Table 1.4-3; See Section 5.3 in App B	na	na	0.0002	0.0002	0.0004	0.0004
				NA	na	S-59	0.0907	Dichlorobenzene	0.0012	AP-42, Table 1.4-3; See Section 5.3 in App B	na	na	0.0001	0.0001	0.0002	0.0002
				NA	na	S-59	0.0907	Formaldehyde	0.075	AP-42, Table 1.4-3; See Section 5.3 in App B	na	na	0.0068	0.0068	0.0136	0.0136
				NA	na	S-59	0.0907	Hexane	1.8	AP-42, Table 1.4-3; See Section 5.3 in App B	na	na	0.1633	0.1633	0.3266	0.3266
				NA	na	S-59	0.0907	Naphthalene	0.00061	AP-42, Table 1.4-3; See Section 5.3 in App B	na	na	0.0001	0.0001	0.0001	0.0001
				NA	na	S-59	0.0907	Toluene	0.0034	AP-42, Table 1.4-3; See Section 5.3 in App B	na	na	0.0003	0.0003	0.0006	0.0006
				NA	na	S-59	0.0907	Arsenic	0.0002	AP-42, Table 1.4-4; See Section 5.3 in App B	na	na	0.0000	0.0000	0.0000	0.0000
				NA	na	S-59	0.0907	Cadmium	0.0011	AP-42, Table 1.4-4; See Section 5.3 in App B	na	na	0.0001	0.0001	0.0002	0.0002
				NA	na	S-59	0.0907	Chromium	0.0014	AP-42, Table 1.4-4; See Section 5.3 in App B	na	na	0.0001	0.0001	0.0003	0.0003
				NA	na	S-59	0.0907	Manganese	0.00038	AP-42, Table 1.4-4; See Section 5.3 in App B	na	na	0.0000	0.0000	0.0001	0.0001
				NA	na	S-59	0.0907	Mercury	0.00026	AP-42, Table 1.4-4; See Section 5.3 in App B	na	na	0.0000	0.0000	0.0000	0.0000
				NA	na	S-59	0.0907	Nickel	0.0021	AP-42, Table 1.4-4; See Section 5.3 in App B	na	na	0.0002	0.0002	0.0004	0.0004
				NA	na	S-59	0.0907	Total HAP	1.88775	Sum; See Section 5.3 in App B	na	na	0.1712	0.1712	0.3425	0.3425

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity *(SCC Units/hour)*	Pollutant	Uncontrolled Emission Factor *(lb/SCC Units)*	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency *(%)*	Control Efficiency *(%)*	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential *(lb/hr)*	Controlled Potential *(lb/hr)*	Uncontrolled Potential *(tons/yr)*	Controlled Potential *(tons/yr)*
60	Fuel Gas (Dewpoint) Preheater															
		1	NG Fuel Combustion (15.65 MMBtu/hr)					SCC Code: 39990003					SCC Units: Million Cubic Feet Natural Gas Burned			
				na	na	S-60	0.0149	NOX	38.339	KU Requirement; See Section 6.3 in App B	na	na	0.570	0.570	2.496	2.496
				na	na	S-60	0.0149	CO	38.900	KU Requirement; See Section 6.3 in App B	na	na	0.578	0.578	2.532	2.532
				na	na	S-60	0.0149	VOC	8.208	AP-42 Table 1.4-2; See Section 6.3 in App B	na	na	0.122	0.122	0.534	0.534
				na	na	S-60	0.0149	PM	1.900	AP-42 Table 1.4-2; See Section 6.3 in App B	na	na	0.028	0.028	0.124	0.124
				na	na	S-60	0.0149	PM10	3.47	AP-42 Table 1.4-2 + EPA Speciate Database; See Section 6.3 in App B	na	na	0.052	0.052	0.226	0.226
				na	na	S-60	0.0149	PM2.5	3.47	AP-42 Table 1.4-2; See Section 6.3 in App B	na	na	0.052	0.052	0.226	0.226
				na	na	S-60	0.0149	SO2	1.43	AP-42 Table 1.4-2 + EPA Speciate Database.; See Section 6.3 in App B	na	na	0.021	0.021	0.093	0.093
				na	na	S-60	0.0149	H2SO4	0.109	Pipeline spec conversion; See Section 6.3 in App B	na	na	0.00162	0.00162	0.00711	0.00711
				na	na	S-60	0.0149	Lead	0.0005	Pipeline spec conversion; See Section 6.3 in App B	na	na	7.43E-06	7.43E-06	3.25E-05	3.25E-05
				na	na	S-60	0.0149	CO2	120,019	AP-42, Table 1.4-2; See Section 6.3 in App B	na	na	1,784	1,784	7,813	7,813
				na	na	S-60	0.0149	CH4	2.26	40 CFR 98, Table C-1; See Section 6.3 in App B	na	na	0.0336	0.0336	0.1472	0.1472
				na	na	S-60	0.0149	N2O	0.226	40 CFR 98, Table C-2; See Section 6.3 in App B	na	na	0.0034	0.0034	0.0147	0.0147
				na	na	S-60	0.0149	CO2e	120,142	40 CFR 98, Table C-2; See Section 6.3 in App B	na	na	1,786	1,786	7,821	7,821
				na	na	S-60	0.0149	Benzene	0.0021	AP-42, Table 1.4-3; See Section 6.3 in App B	na	na	3.12E-05	3.12E-05	1.37E-04	1.37E-04
				na	na	S-60	0.0149	Dichlorobenzene	0.0012	AP-42, Table 1.4-3; See Section 6.3 in App B	na	na	1.78E-05	1.78E-05	7.81E-05	7.81E-05
				na	na	S-60	0.0149	Formaldehyde	0.0750	AP-42, Table 1.4-3; See Section 6.3 in App B	na	na	1.11E-03	1.11E-03	4.88E-03	4.88E-03
				na	na	S-60	0.0149	Hexane	1.80	AP-42, Table 1.4-3; See Section 6.3 in App B	na	na	2.68E-02	2.68E-02	1.17E-01	1.17E-01

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
				na	na	S-60	0.0149	Naphthalene	6.10E-04	AP-42, Table 1.4-3; See Section 6.3 in App B	na	na	9.07E-06	9.07E-06	3.97E-05	3.97E-05
				na	na	S-60	0.0149	Toluene	3.40E-03	AP-42, Table 1.4-3; See Section 6.3 in App B	na	na	5.05E-05	5.05E-05	2.21E-04	2.21E-04
				na	na	S-60	0.0149	Arsenic	2.00E-04	AP-42, Table 1.4-4; See Section 6.3 in App B	na	na	2.97E-06	2.97E-06	1.30E-05	1.30E-05
				na	na	S-60	0.0149	Cadmium	1.10E-03	AP-42, Table 1.4-4; See Section 6.3 in App B	na	na	1.63E-05	1.63E-05	7.16E-05	7.16E-05
				na	na	S-60	0.0149	Chromium	1.40E-03	AP-42, Table 1.4-4; See Section 6.3 in App B	na	na	2.08E-05	2.08E-05	9.11E-05	9.11E-05
				na	na	S-60	0.0149	Manganese	3.80E-04	AP-42, Table 1.4-4; See Section 6.3 in App B	na	na	5.65E-06	5.65E-06	2.47E-05	2.47E-05
				na	na	S-60	0.0149	Mercury	2.60E-04	AP-42, Table 1.4-4; See Section 6.3 in App B	na	na	3.86E-06	3.86E-06	1.69E-05	1.69E-05
				na	na	S-60	0.0149	Nickel	2.10E-03	AP-42, Table 1.4-4; See Section 6.3 in App B	na	na	3.12E-05	3.12E-05	1.37E-04	1.37E-04
				na	na	S-60	0.0149	Total HAP	1.8878	Sum; See Section 6.3 in App B	na	na	0.02806	0.02806	0.12289	0.12289
61	2.18 MW Diesel Emergency Generator															
		1	Diesel Fuel Combustion					SCC Code: 20100102			SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned					
				na	na	S-61	0.1490	NOx	201.137	= 6.4 g/kW-hr * 0.974 / 1.341 hp/kW; See Section 7.2 in App B	na	na	29.969	29.969	7.49	7.49
				na	na	S-61	0.1490	CO	111.350	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I; See Section 7.2 in App B	na	na	16.591	16.591	4.15	4.15
				na	na	S-61	0.1490	VOC	5.375	= 6.4 g/bhp-hr * 0.026 / 1.341 hp/kW; See Section 7.2 in App B	na	na	0.801	0.801	0.200	0.200
				na	na	S-61	0.1490	PM	6.363	Tier 2 NSPS IIII Standard => 40 CFR 1039, Appendix I; See Section 7.2 in App B	na	na	0.948	0.948	0.237	0.237
				na	na	S-61	0.1490	PM10	6.363	||	na	na	0.948	0.948	0.237	0.237
				na	na	S-61	0.1490	PM2.5	6.363	||	na	na	0.948	0.948	0.237	0.237
				na	na	S-61	0.1490	SO2	0.208	AP-42 Table 3.4-1; See Section 7.2 in App B	na	na	0.031	0.031	0.008	0.008
				na	na	S-61	0.1490	CO2	22,501	40 CFR 98, Subpart C, Table C-1; See Section 7.2 in App B	na	na	3,353	3,353	838.18	838.18

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
				na	na	S-61	0.1490	CH4	0.913	40 CFR 98, Subpart C, Table C-2; See Section 7.2 in App B	na	na	0.136	0.136	0.034	0.034
				na	na	S-61	0.1490	N2O	0.183	40 CFR 98, Subpart C, Table C-2; See Section 7.2 in App B	na	na	0.027	0.027	0.007	0.007
				na	na	S-61	0.1490	CO2e	22,575	40 CFR 98, Subpart A; See Section 7.2 in App B	na	na	3,364	3,364	840.93	840.93
				na	na	S-61	0.1490	Acetaldehyde	0.0035	AP-42 Table 3.4-3; See Section 7.2 in App B	na	na	5.15E-04	5.15E-04	1.29E-04	1.29E-04
				na	na	S-61	0.1490	Acrolein	0.0011	AP-42 Table 3.4-3; See Section 7.2 in App B	na	na	1.61E-04	1.61E-04	4.02E-05	4.02E-05
				na	na	S-61	0.1490	Benzene	0.1063	AP-42 Table 3.4-3; See Section 7.2 in App B	na	na	1.58E-02	1.58E-02	3.96E-03	3.96E-03
				na	na	S-61	0.1490	Formaldehyde	0.0108	AP-42 Table 3.4-3; See Section 7.2 in App B	na	na	1.61E-03	1.61E-03	4.03E-04	4.03E-04
				na	na	S-61	0.1490	Naphthalene	0.0178	AP-42 Table 3.4-4; See Section 7.2 in App B	na	na	2.65E-03	2.65E-03	6.64E-04	6.64E-04
				na	na	S-61	0.1490	PAH	0.0291	AP-42 Table 3.4-4; See Section 7.2 in App B	na	na	4.33E-03	4.33E-03	1.08E-03	1.08E-03
				na	na	S-61	0.1490	Toluene	0.0385	AP-42 Table 3.4-3; See Section 7.2 in App B	na	na	5.74E-03	5.74E-03	1.43E-03	1.43E-03
				na	na	S-61	0.1490	Xylenes	0.0264	AP-42 Table 3.4-3; See Section 7.2 in App B	na	na	3.94E-03	3.94E-03	9.85E-04	9.85E-04
				na	na	S-61	0.1490	Total HAP	0.2335	AP-42 Table 3.4-3; See Section 7.2 in App B	na	na	3.48E-02	3.48E-02	8.70E-03	8.70E-03
62	422 HP Diesel Driven Fire Pump															
		1	Diesel Fuel Combustion					SCC Code: 20100102					SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned			
				na	na	S-62	0.0216	NOx	159.678	= 4 g/kW-hr * 0.925 / 1.341 hp/kW; See Section 8.2 in App B	na	na	3.442	3.442	0.86	0.86
				na	na	S-62	0.0216	CO	112.208	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII) ;	na	na	2.419	2.419	0.60	0.60
				na	na	S-62	0.0216	VOC	9.657	= 4 g/bhp-hr * 0.075 / 1.341 hp/kW; See Section 8.2 in App B	na	na	0.208	0.208	0.052	0.052
				na	na	S-62	0.0216	PM	6.474	Emission Standards for Stationary Pumps per NSPS IIII (Table 4 to Subpart IIII) ;	na	na	0.140	0.140	0.035	0.035
				na	na	S-62	0.0216	PM10	6.474	||	na	na	0.140	0.140	0.035	0.035

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity *(SCC Units/hour)*	Pollutant	Uncontrolled Emission Factor *(lb/SCC Units)*	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency *(%)*	Control Efficiency *(%)*	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential *(lb/hr)*	Controlled Potential *(lb/hr)*	Uncontrolled Potential *(tons/yr)*	Controlled Potential *(tons/yr)*
				na	na	S-62	0.0216	PM2.5	6.474	||	na	na	0.140	0.140	0.035	0.035
				na	na	S-62	0.0216	SO2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %); See Section 8.2 in App B	na	na	0.004	0.004	0.0011	0.0011
				na	na	S-62	0.0216	CO2	22,343	40 CFR 98, Subpart C, Table C-1; See Section 8.2 in App B	na	na	481.7	481.7	120.42	120.42
				na	na	S-62	0.0216	CH4	0.906	40 CFR 98, Subpart C, Table C-2; See Section 8.2 in App B	na	na	0.020	0.020	0.0049	0.0049
				na	na	S-62	0.0216	N2O	0.181	40 CFR 98, Subpart C, Table C-2; See Section 8.2 in App B	na	na	0.0039	0.0039	0.0010	0.0010
				na	na	S-62	0.0216	CO2e	22,417	40 CFR 98, Subpart A; See Section 8.2 in App B	na	na	483.2	483.2	120.81	120.81
				na	na	S-62	0.0216	1,3-Butadiene	0.0054	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	1.16E-04	1.16E-04	2.89E-05	2.89E-05
				na	na	S-62	0.0216	Acetaldehyde	0.1051	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	2.27E-03	2.27E-03	5.66E-04	5.66E-04
				na	na	S-62	0.0216	Acrolein	0.0127	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	2.73E-04	2.73E-04	6.83E-05	6.83E-05
				na	na	S-62	0.0216	Benzene	0.1278	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	2.76E-03	2.76E-03	6.89E-04	6.89E-04
				na	na	S-62	0.0216	Formaldehyde	0.1617	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	3.49E-03	3.49E-03	8.71E-04	8.71E-04
				na	na	S-62	0.0216	Naphthalene	0.0116	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	2.50E-04	2.50E-04	6.26E-05	6.26E-05
				na	na	S-62	0.0216	PAH	0.0230	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	4.96E-04	4.96E-04	1.24E-04	1.24E-04
				na	na	S-62	0.0216	Toluene	0.0560	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	1.21E-03	1.21E-03	3.02E-04	3.02E-04
				na	na	S-62	0.0216	Xylenes	0.0391	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	8.42E-04	8.42E-04	2.10E-04	2.10E-04
				na	na	S-62	0.0216	Total HAP	0.5424	AP-42 Table 3.3-2; See Section 7.2 in App B	na	na	1.17E-02	1.17E-02	2.92E-03	2.92E-03

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
63	Mechanical Draft Cooling Tower (10 Cells)															
		1	Gallons of Recirculating Water					SCC Code: 38500101					SCC Units: Million Gallons Cooling Water Throughput			
				Drift Eliminators	C36	S-63	5.7	PM	0.0826	990 ppm TDS in recirculating water and 0.001% drift; See Section 9.2 in Appendix B	na	na	0.47	0.47	2.06	2.06
				Drift Eliminators	C36	S-63	5.7	PM10	0.0388	EPRI PM10/PM ratio; See Section 9.2 in Appendix B	na	na	0.22	0.22	0.97	0.97
				Drift Eliminators	C36	S-63	5.7	PM2.5	1.67E-04	EPRI PM2.5/PM ratio; See Section 9.2 in Appendix B	na	na	9.51E-04	9.51E-04	4.16E-03	4.16E-03
64	Turbine Circuit Breaker with 30 lb. SF6 circuit															
		1	SF6 Releases					SCC Code: 20180001					SCC Units: Each-Year Facility Operating			
				0	0	S-64	1	CO2e	0.4024	= 1 breakers * 30 lb SF6/breaker * 0.5% leak rate/yr / 2,000 lb/ton	na	na	0.40	0.40	1.76	1.76
65	Lube Oil System with Demister Vents															
		1	Evaporative losses					SCC Code: 20180001					SCC Units: Each-Year Facility Operating			
				N/A	N/A	S-65	1	VOC	0.1517	Unit Conversion: 0.5 gal/day / 24 hr/day	na	na	0.15	0.15	0.66	0.66
66	Diesel Storage Tank for Generator (3,733 gal)															
		1	Breathing Losses					SCC Code: 42500301					SCC Units: 1000 Gallon-Years Liquid Storage Capacity			
				N/A	N/A	S-66	4.26E-04	VOC	4.1857	TankESP and AP42 Section 7.1; See Section 12.1 in App B	na	na	1.78E-03	1.78E-03	7.81E-03	7.81E-03
		2	Working Losses					SCC Code: 42500302					SCC Units: 1000 Gallons Liquid Throughput			
				N/A	N/A	S-66	8.50E-03	VOC	0.0011	TankESP and AP42 Section 7.1; See Section 12.1 in App B	na	na	9.64E-06	9.64E-06	4.22E-05	4.22E-05
67	Diesel Storage Tank for Firewater Pump (300 gal)															
		1	Breathing Losses					SCC Code: 42500301					SCC Units: 1000 Gallon-Years Liquid Storage Capacity			
				N/A	N/A	S-67	3.42E-05	VOC	0.2567	TankESP and AP42 Section 7.1; See Section 12.1 in App B	na	na	8.79E-06	8.79E-06	3.85E-05	3.85E-05
		2	Working Losses					SCC Code: 42500302					SCC Units: 1000 Gallons Liquid Throughput			
				N/A	N/A	S-67	1.23E-03	VOC	0.0006	TankESP and AP42 Section 7.1; See Section 12.1 in App B	na	na	7.20E-07	7.20E-07	3.15E-06	3.15E-06

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity *(SCC Units/hour)*	Pollutant	Uncontrolled Emission Factor *(lb/SCC Units)*	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency *(%)*	Control Efficiency *(%)*	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential *(lb/hr)*	Controlled Potential *(lb/hr)*	Uncontrolled Potential *(tons/yr)*	Controlled Potential *(tons/yr)*
68	NGCC Haul Roads															
		1	Paved Aq. NH3 Transport					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.0531	PM	0.7273	AP-42, Section 13.2.1	na	na	0.0386	0.0386	0.1691	0.1691
				Dust Suppression	NA	Fugitive	0.0531	PM10	0.1416	AP-42, Section 13.2.1	na	na	0.0075	0.0075	0.0329	0.0329
				Dust Suppression	NA	Fugitive	0.0531	PM2.5	2.10E-02	AP-42, Section 13.2.1	na	na	0.0011	0.0011	0.0049	0.0049
		2	Paved Cooling Twr Chemicals Transport					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.0195	PM	0.7615	AP-42, Section 13.2.1	na	na	0.0149	0.0149	0.0651	0.0651
				Dust Suppression	NA	Fugitive	0.0195	PM10	0.1482	AP-42, Section 13.2.1	na	na	0.0029	0.0029	0.0127	0.0127
				Dust Suppression	NA	Fugitive	0.0195	PM2.5	2.20E-02	AP-42, Section 13.2.1	na	na	0.0004	0.0004	0.0019	0.0019
		3	Paved Water Treatment Chemicals Transport					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.0026	PM	0.2403	AP-42, Section 13.2.1	na	na	0.0006	0.0006	0.0027	0.0027
				Dust Suppression	NA	Fugitive	0.0026	PM10	0.0465	AP-42, Section 13.2.1	na	na	0.0001	0.0001	0.0005	0.0005
				Dust Suppression	NA	Fugitive	0.0026	PM2.5	6.72E-03	AP-42, Section 13.2.1	na	na	0.0000	0.0000	0.0001	0.0001
69	Natural Gas Piping Fugitives															
		1	Gas/Vapor Valves					SCC Code: 30600811					SCC Units: Each-Year Valve Operating			
				N/A	N/A	Fugitive	0.035	VOC	0.329	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.011	0.011	0.050	0.050
				N/A	N/A	Fugitive	0.035	CO2	3.209	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.111	0.111	0.488	0.488
				N/A	N/A	Fugitive	0.035	CH4	73.594	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	2.554	2.554	11.186	11.186
				N/A	N/A	Fugitive	0.035	CO2e	2,063.84	CO2 * CO2 GWP + CH4 * CH4 GWP; See Section 14.4 in App B	na	na	71.622	71.622	313.704	313.704

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
		2	Relief Valves					SCC Code: 30600822			SCC Units: Each-Year Valve Operating					
				N/A	N/A	Fugitive	0.0029	VOC	0.644	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.002	0.002	0.008	0.008
				N/A	N/A	Fugitive	0.0029	CO2	6.275	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.018	0.018	0.078	0.078
				N/A	N/A	Fugitive	0.0029	CH4	143.917	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.411	0.411	1.799	1.799
				N/A	N/A	Fugitive	0.0029	CO2e	4,035.95	CO2 * CO2 GWP + CH4 * CH4 GWP; See Section 14.4 in App B	na	na	11.518	11.518	50.449	50.449
		3	Flanges					SCC Code: 30600816			SCC Units: Each-Year Flange Operating					
				N/A	N/A	Fugitive	0.0566	VOC	0.029	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.002	0.002	0.007	0.007
				N/A	N/A	Fugitive	0.0566	CO2	0.278	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.016	0.016	0.069	0.069
				N/A	N/A	Fugitive	0.0566	CH4	6.378	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.361	0.361	1.582	1.582
				N/A	N/A	Fugitive	0.0566	CO2e	178.87	CO2 * CO2 GWP + CH4 * CH4 GWP; See Section 14.4 in App B	na	na	10.128	10.128	44.359	44.359
		4	Vents					SCC Code: 20180001			SCC Units: Each-Year Facility Operating					
				N/A	N/A	Fugitive	0.0079	VOC	0.644	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.005	0.005	0.022	0.022
				N/A	N/A	Fugitive	0.0079	CO2	6.275	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	0.049	0.049	0.217	0.217
				N/A	N/A	Fugitive	0.0079	CH4	143.917	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	1.134	1.134	4.965	4.965
				N/A	N/A	Fugitive	0.0079	CO2e	4,035.95	CO2 * CO2 GWP + CH4 * CH4 GWP; See Section 14.4 in App B	na	na	31.790	31.790	139.240	139.240
		5	Compressors Components					SCC Code: 30600819			SCC Units: Each-Year Seal Operating					
				N/A	N/A	Fugitive	3.42E-04	VOC	0.644	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	2.20E-04	2.20E-04	9.66E-04	9.66E-04
				N/A	N/A	Fugitive	3.42E-04	CO2	6.275	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	2.15E-03	2.15E-03	9.41E-03	9.41E-03
				N/A	N/A	Fugitive	3.42E-04	CH4	143.917	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	4.93E-02	4.93E-02	2.16E-01	2.16E-01
				N/A	N/A	Fugitive	3.42E-04	CO2e	4,035.95	CO2 * CO2 GWP + CH4 * CH4 GWP; See Section 14.4 in App B	na	na	1.382	1.382	6.054	6.054

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity *(SCC Units/hour)*	Pollutant	Uncontrolled Emission Factor *(lb/SCC Units)*	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency *(%)*	Control Efficiency *(%)*	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential *(lb/hr)*	Controlled Potential *(lb/hr)*	Uncontrolled Potential *(tons/yr)*	Controlled Potential *(tons/yr)*
		6	Sampling Connections					SCC Code: 30600811			SCC Units: Each-Year Valve Operating					
				N/A	N/A	Fugitive	3.42E-04	VOC	0.644	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	2.20E-04	2.20E-04	9.66E-04	9.66E-04
				N/A	N/A	Fugitive	3.42E-04	CO2	6.275	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	2.15E-03	2.15E-03	9.41E-03	9.41E-03
				N/A	N/A	Fugitive	3.42E-04	CH4	143.917	Document EPA-453/R-95/017, November 1995; See Section 14.4 in App B	na	na	4.93E-02	4.93E-02	2.16E-01	2.16E-01
				N/A	N/A	Fugitive	3.42E-04	CO2e	4,035.95	CO2 * CO2 GWP + CH4 * CH4 GWP; See Section 14.4 in App B	na	na	1.382	1.382	6.054	6.054
70	93% Sulfuric Acid Tank															
		1	Breathing Losses					SCC Code: 42500301			SCC Units: 1000 Gallon-Years Liquid Storage Capacity					
				N/A	N/A	S-70	0.00139	H2SO4	6.60E-05	TankESP and AP42 Section 7.1; See Section 15.2 in App B	na	na	9.19E-08	9.19E-08	4.02E-07	4.02E-07
		2	Working Losses					SCC Code: 42500302			SCC Units: 1000 Gallons Liquid Throughput					
				N/A	N/A	S-70	0.0167	H2SO4	4.37E-07	TankESP and AP42 Section 7.1; See Section 15.2 in App B	na	na	7.30E-09	7.30E-09	3.20E-08	3.20E-08

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
The changes shown below are unrelated to BR12 NGCC Project.																
35	Paved and Unpaved Roads															
		1	Roadways					SCC Code: 30502011					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	3.4725	PM	1.0389	AP-42, Section 13.2.1 & 13.2.2	na	na	3.6076	3.6076	15.8012	15.8012
				Dust Suppression	NA	Fugitive	3.4725	PM10	0.2056	AP-42, Section 13.2.1 & 13.2.2	na	na	0.7139	0.7139	3.1270	3.1270
				Dust Suppression	NA	Fugitive	3.4725	PM2.5	2.98E-02	AP-42, Section 13.2.1 & 13.2.2	na	na	0.1034	0.1034	0.4529	0.4529
* Unrelated to BR12 NGCC Project. This total includes reduced amount of possible deliveries for coal and KU increased the amount of other process trucks to 20,000 per year. As a result, the weighted average emissions factors also changed. 30,420 VMT = 17,900 coal haul trips * 2.0 miles of paved roads + 41,667 limestone FEL trips/yr on unpaved roads * 0.01 miles + 10,000 limestone haul trips * 0.91 miles of paved roads + 20,000 other delivery VMT * 5% unpaved roads + 20,000 other delivery VMT * 95% paved roads																
EU 50	CCR Landfill Operations and Haul Trucks															
		1	Unpaved Empty Bottom Ash Transport					SCC Code: 30502504					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.0163	PM	3.9223	AP-42, Section 13.2.2	na	70.00%	0.0638	0.0191	0.2793	0.0838
				Dust Suppression	NA	Fugitive	0.01626	PM10	0.9590	AP-42, Section 13.2.2	na	70.00%	0.0156	0.0047	0.0683	0.0205
				Dust Suppression	NA	Fugitive	0.0163	PM2.5	9.59E-02	AP-42, Section 13.2.2	na	70.00%	0.0016	0.0005	0.0068	0.0020
* Unrelated to BR12 NGCC Project. Underlying front end loader traffic VMT was corrected: 100 ft distance, 0 feet paved and 100 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on paved road activity.																
		2	Paved Full Fly Ash Transport					SCC Code: 30502504					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.0000	PM	0.0000	AP-42, Section 13.2.1	na	70.00%	0.0000	0.0000	0.0000	0.0000
				Dust Suppression	NA	Fugitive	0.0000	PM10	0.0000	AP-42, Section 13.2.1	na	70.00%	0.0000	0.0000	0.0000	0.0000
				Dust Suppression	NA	Fugitive	0.0000	PM2.5	0.00E+00	AP-42, Section 13.2.1	na	70.00%	0.0000	0.0000	0.0000	0.0000
* Unrelated to BR12 NGCC Project. Fly ash is no longer handed by front end loaders.																

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
		3	Unpaved Empty Gypsum-Like Transport					SCC Code: 30502504			SCC Units: Miles Vehicle Travelled					
				Dust Suppression	NA	Fugitive	0.1268	PM	3.9223	AP-42, Section 13.2.2	na	70.00%	0.4972	0.1492	2.1778	0.6534
				Dust Suppression	NA	Fugitive	0.1268	PM10	0.9590	AP-42, Section 13.2.2	na	70.00%	0.1216	0.0365	0.5325	0.1597
				Dust Suppression	NA	Fugitive	0.1268	PM2.5	9.59E-02	AP-42, Section 13.2.2	na	70.00%	0.0122	0.0036	0.0532	0.0160
* Unrelated to BR12 NGCC Project. Underlying front end loader traffic VMT was corrected: 100 ft distance, 0 feet paved and 100 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on paved road activity.																
		4	Unpaved Full Bottom Ash Transport					SCC Code: 30502504			SCC Units: Miles Vehicle Travelled					
				Dust Suppression	NA	Fugitive	0.0163	PM	4.2841	AP-42, Section 13.2.2	na	70.00%	0.0697	0.0209	0.3051	0.0915
				Dust Suppression	NA	Fugitive	0.0163	PM10	1.0475	AP-42, Section 13.2.2	na	70.00%	0.0170	0.0051	0.0746	0.0224
				Dust Suppression	NA	Fugitive	0.0163	PM2.5	1.05E-01	AP-42, Section 13.2.2	na	70.00%	0.0017	0.0005	0.0075	0.0022
* Unrelated to BR12 NGCC Project. Underlying front end loader traffic VMT was corrected: 100 ft distance, 0 feet paved and 100 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on paved road activity.																
		5	Paved Empty Fly Ash Transport					SCC Code: 30502504			SCC Units: Miles Vehicle Travelled					
				Dust Suppression	NA	Fugitive	0.0000	PM	0.0000	AP-42, Section 13.2.1	na	70.00%	0.0000	0.0000	0.0000	0.0000
				Dust Suppression	NA	Fugitive	0.0000	PM10	0.0000	AP-42, Section 13.2.1	na	70.00%	0.0000	0.0000	0.0000	0.0000
				Dust Suppression	NA	Fugitive	0.0000	PM2.5	0.00E+00	AP-42, Section 13.2.1	na	70.00%	0.0000	0.0000	0.0000	0.0000
* Unrelated to BR12 NGCC Project. Fly ash is no longer handed by front end loaders.																
		6	Unpaved Full Gypsum-Like Transport					SCC Code: 30502504			SCC Units: Miles Vehicle Travelled					
				Dust Suppression	NA	Fugitive	0.1268	PM	4.2841	AP-42, Section 13.2.2	na	70.00%	0.5431	0.1629	2.3787	0.7136
				Dust Suppression	NA	Fugitive	0.1268	PM10	1.0475	AP-42, Section 13.2.2	na	70.00%	0.1328	0.0398	0.5816	0.1745
				Dust Suppression	NA	Fugitive	0.1268	PM2.5	1.05E-01	AP-42, Section 13.2.2	na	70.00%	0.0133	0.0040	0.0582	0.0174
* Unrelated to BR12 NGCC Project. Underlying front end loader traffic VMT was corrected: 100 ft distance, 0 feet paved and 100 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on paved road activity.																

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
		7	Paved/Unpaved Empty Bottom Ash Transport					SCC Code: 30502504					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.0482	PM	3.3624	AP-42, Section 13.2.1	na	70.00%	0.1621	0.0486	0.7099	0.2130
				Dust Suppression	NA	Fugitive	0.0482	PM10	0.8205	AP-42, Section 13.2.1	na	70.00%	0.0396	0.0119	0.1732	0.0520
				Dust Suppression	NA	Fugitive	0.0482	PM2.5	8.31E-02	AP-42, Section 13.2.1	na	70.00%	0.0040	0.0012	0.0175	0.0053
* Unrelated to BR12 NGCC Project. Underlying front end loader traffic VMT was corrected: 100 ft distance, 0 feet paved and 100 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on paved road activity.																
		8	Paved/Unpaved Full Bottom Ash Transport					SCC Code: 30502504					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.0482	PM	5.3629	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.2585	0.0775	1.1322	0.3397
				Dust Suppression	NA	Fugitive	0.0482	PM10	1.3068	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.0630	0.0189	0.2759	0.0828
				Dust Suppression	NA	Fugitive	0.0482	PM2.5	1.34E-01	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.0064	0.0019	0.0282	0.0085
* Unrelated to BR12 NGCC Project. Underlying VMT was corrected: 2100 ft distance to landfill, 200 feet paved and 1900 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on unpaved road activity.																
		9	Paved/Unpaved Empty Fly Ash Transport					SCC Code: 30502504					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.2112	PM	3.1022	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.6552	0.1966	2.8696	0.8609
				Dust Suppression	NA	Fugitive	0.2112	PM10	0.7556	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.1596	0.0479	0.6990	0.2097
				Dust Suppression	NA	Fugitive	0.2112	PM2.5	7.74E-02	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.0164	0.0049	0.0716	0.0215
* Unrelated to BR12 NGCC Project. Underlying VMT was corrected: 2100 ft distance to landfill, 200 feet paved and 1900 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on unpaved road activity.																
		10	Paved/Unpaved Full Fly Ash Transport					SCC Code: 30502504					SCC Units: Miles Vehicle Travelled			
				Dust Suppression	NA	Fugitive	0.2112	PM	4.9878	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	1.0534	0.3160	4.6138	1.3841
				Dust Suppression	NA	Fugitive	0.2112	PM10	1.2114	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.2558	0.0767	1.1205	0.3362
				Dust Suppression	NA	Fugitive	0.2112	PM2.5	1.26E-01	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.0267	0.0080	0.1170	0.0351
* Unrelated to BR12 NGCC Project. Underlying VMT was corrected: 2100 ft distance to landfill, 200 feet paved and 1900 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on unpaved road activity.																

Emission Unit #	Emission Unit Name	Process ID	Process Name	Control Device Name	Control Device ID	Stack ID	Maximum Design Capacity (SCC Units/hour)	Pollutant	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Source (e.g. AP-42, Stack Test, Mass Balance)	Capture Efficiency (%)	Control Efficiency (%)	Hourly Emissions		Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
		11	Paved/Unpaved Empty Gypsum-Like Transport					SCC Code: 30502504			SCC Units: Miles Vehicle Travelled					
				Dust Suppression	NA	Fugitive	0.3579	PM	3.5119	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	1.2570	0.3771	5.5058	1.6517
				Dust Suppression	NA	Fugitive	0.3579	PM10	0.8578	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.3070	0.0921	1.3449	0.4035
				Dust Suppression	NA	Fugitive	0.3579	PM2.5	8.63E-02	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.0309	0.0093	0.1353	0.0406
* Unrelated to BR12 NGCC Project. Underlying VMT was corrected: 2100 ft distance to landfill, 200 feet paved and 1900 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on unpaved road activity.																
		12	Paved/Unpaved Full Gypsum-Like Transport					SCC Code: 30502504			SCC Units: Miles Vehicle Travelled					
				Dust Suppression	NA	Fugitive	0.3579	PM	5.5786	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	1.9967	0.5990	8.7458	2.6237
				Dust Suppression	NA	Fugitive	0.3579	PM10	1.3616	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.4874	0.1462	2.1346	0.6404
				Dust Suppression	NA	Fugitive	0.3579	PM2.5	1.38E-01	AP-42, Section 13.2.1 & 13.2.2	na	70.00%	0.0493	0.0148	0.2159	0.0648
* Unrelated to BR12 NGCC Project. Underlying VMT was corrected: 2100 ft distance to landfill, 200 feet paved and 1900 feet unpaved. Number of trips remained unchanged. Prior evaluation was based solely on unpaved road activity.																
		13	Travel Heavy Equip. Landfill					SCC Code: 30502504			SCC Units: Miles Vehicle Travelled					
				Dust Suppression	NA	Fugitive	0.0417	PM	4.2841	AP-42, Section 13.2.2	na	70.00%	0.1785	0.0536	0.7819	0.2346
				Dust Suppression	NA	Fugitive	0.0417	PM10	1.0475	AP-42, Section 13.2.2	na	70.00%	0.0436	0.0131	0.1912	0.0573
				Dust Suppression	NA	Fugitive	0.0417	PM2.5	1.05E-01	AP-42, Section 13.2.2	na	70.00%	0.0044	0.0013	0.0191	0.0057
* No changes to underlying basis of EU 50-13, included for informational purposes only.																

Section N.2: Stack Information

UTM Zone: 16 S

Stack ID	Identify all Emission Units (with Process ID) and Control Devices that Feed to Stack	Stack Physical Data			Stack UTM Coordinates		Stack Gas Stream Data		
		Equivalent Diameter *(ft)*	Height *(ft)*	Base Elevation *(ft)*	Northing *(m)*	Easting *(m)*	Flowrate *(acfm)*	Temperature *(° F)*	Exit Velocity *(ft/sec)*
S-58	Unit 12 Gas Turbine with HRSG and DB, Control Devices: Oxidation Catalyst; SCR	24	185	895	4,184,832	701,606	1,600,000	171	59
S-59	Auxiliary Steam Boiler, Control Devices: NA	3.5	50	895	4,184,864	701,618	26,298	300	46
S-60	Fuel Gas (Dewpoint) Preheater, Control Devices:	1.96	25	895	4,185,208	700,848	8,233	500	46
S-61	2.18 MW Diesel Emergency Generator, Control Devices:	1.00	15.42	895	4,184,884.00	701,588.00	926	932	20
		1.00	15.42	895	4,184,884.20	701,588.34	926	932	20
		1.00	15.42	895	4,184,884.00	701,588.78	926	932	20
S-62	422 HP Diesel Driven Fire Pump, Control Devices:	0.50	13	895	4,184,920	701,630	2,048	891	174
S-63	Mechanical Draft Cooling Tower (10 Cells), Control Device: Drift Eliminators	35.625	55	895	4,184,796	701,673	1,350,000	88	23
		Setup as 12 cells							

Section N.3: Fugitive Information

UTM Zone:

Emission Unit #	Emission Unit Name	Process ID	Area Physical Data		Area UTM Coordinates		Area Release Data	
			Length of the X Side *(ft)*	Length of the Y Side *(ft)*	Northing *(m)*	Easting *(m)*	Release Temperature *(°F)*	Release Height *(ft)*
See Modeling Files								

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Section N.4: Notes, Comments, and Explanations

Division for Air Quality

300 Sower Boulevard

Frankfort, KY 40601

(502) 564-3999

DEP7007GG

Control Equipment

Additional Documentation

___ Complete Sections GG.1 through GG.12, as applicable
___ Attach manufacturer's specifications for each control device
___ Complete DEP7007AI

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)

#: 21- 167-00001

Permit #: V-17-030 R1

Agency Interest (AI) II 3148

Date: March 25, 2025

Section GG.1: General Information - Control Equipment

Control Device ID #	Control Device Name	Cost	Manufacturer	Model Name/ Serial #	Date Installed	Inlet Gas Stream Data For All Control Devices					Inlet Gas Stream Data For Condensers, Adsorbers, Afterburners, Incinerators, Oxidizers Only			Equipment Operational Data For All Control Devices		
						Temperature (°F)	Flowrate (scfm @ 68°F)	Average Particle Diameter (μm)	Particle Density (lb/ft^3) or Specific Gravity	Gas Density (lb/ft^3)	Gas Moisture Content (%)	Gas Composition	Fan Type	Pressure Drop Range (in. H_2O)	Pollutants Collected/ Controlled	Pollutant Removal (%)
C34	Oxidation Catalyst	na	See GG.12	na	06/2026	600-1,200	na	na	na	na	na	na	na	0.5-1.0	CO VOC	90% 50%
C35	SCR	na	See GG.12	na	06/2026	575-625	na	na	na	na	na	na	na	0.6-1.0	NOX	90%
C36	Drift Eliminators	na	See GG.12	na	06/2026	na	na	na	na	na	na	na	na	na	PM	Drift Loss = 0.1000%

Section GG.10: Selective Catalytic Reduction (SCR) / Selective Non-catalytic Reduction (SNCR)

Control Device ID #	Identify all Emission Units and Control Devices that Feed to SCR/SNCR	Type (SCR/SNCR)	Gas Composition	Injection Grid Design (e.g. honeycomb)	Design Temperature Range		Reagent			Maximum Design Ammonia Slip (ppm)	SCR Only			
											Catalyst			
					Min (°F)	Max (°F)	Type	Injection Rate Min (lb/hr)	Injection Rate Max (lb/hr)		Composition	Volume (ft^3)	Weight (lb)	Replacement Schedule
C35	COMB19, 58 - Unit 12 Gas Turbine with HRSG and DB; Refer to Process Flow Diagram in Appendix B	SCR	Refer to Section 4 in Appendix B	na	550	700	NH_3	400	700	5	TiO_2 ceramic substrate with transition metals such as Vanadium, Tungsten, and Molybdenum as activation sites	18,750	85,000	Expected to be scheduled seven to ten years dependent upon actual degradation.

Section GG.11: Other Control Equipment

Control Device ID #	Identify all Emission Units and Control Devices that Feed to Control Equipment	**Type of Control Equipment** (provide description and a diagram with dimensions)
C34	COMB19, 58 - Unit 12 Gas Turbine with HRSG and DB; Refer to Process Flow Diagram in Appendix B	Oxidation Catalyst - Refer to Process Flow Diagram in Appendix A
C36	EQPT21, 63 - Mechanical Draft Cooling Tower (10 Cells); Refer to Process Flow Diagram in Appendix B	Integrated Mist Eliminator with Drift Loss Specification of no greater than 0.0010%

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Section GG.12: Notes, Comments, and Explanations
Construction of equipment associated with the NGCC Project is not targeted to commence until June 2026. The specific vendors and model numbers of air pollution control equipment planned will not be known until farther in the project schedule.

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Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
(502) 564-3999

DEP7007V

Applicable Requirements and Compliance Activities

___ Section V.1: Emission and Operating Limitation(s)
___ Section V.2: Monitoring Requirements
___ Section V.3: Recordkeeping Requirements
___ Section V.4: Reporting Requirements
___ Section V.5: Testing Requirements
___ Section V.6: Notes, Comments, and Explanations

Additional Documentation

___ Complete DEP7007AI

Source Name: Kentucky Utilities Company (E.W. Brown Generating Station)
KY EIS (AFS) : 21- 167-00001
Permit #: V-17-030 R1
Agency Interest (AI) ID: 3148
Date: March 25, 2025

Section V.1: Emission and Operating Limitation(s)

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	40 CFR 60.4333(a); 40 CFR 60.5525a(b); 40 CFR 63.6105(c)	na	na	na	Operate and maintain the emissions unit, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.	Operate the affected source in a manner consistent with safety and good air pollution control practices.

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	40 CFR 60.4320(a)	NO_X	For turbines operating at peak load: 15 ppm at 15% O2, or 0.43 lb/MWh gross energy output, based upon a 30-unit operating day rolling average For turbines operating at less than 75% of peak load: 96 ppm at 15% O2, or 4.7 lb/MWh gross energy output, based upon a 30-unit operating day rolling average	na	na	NOX continuous emission monitoring.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	40 CFR 60.4330(a)(2)	SO_2	na	na	The owner or operator shall not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input.	Monitor fuel quality characteristics in purchase contract or tariff sheet
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	40 CFR 63.6100	CH_2O	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in 40 CFR 63.6175.	na	na	Continuously monitoring the inlet temperature to the catalyst and maintain the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer.
COMB19, 58	Unit 12 Gas Turbine (DB Firing Only)	401 KAR 59:015. Section 4(1)(b)	PM	0.1 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
COMB19, 58	Unit 12 Gas Turbine (DB Firing Only)	401 KAR 59:015, Section 4(2)	Opacity	20%	na	na	Equipment design and use of natural gas as fuel.
COMB19, 58	Unit 12 Gas Turbine (DB Firing Only)	401 KAR 59:015, Section 5(1)(b)	SO2	0.8 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
COMB19, 58	Unit 12 Gas Turbine (DB Firing Only)	401 KAR 59:015, Section 7; 401 KAR 59:015, Section 7(1)	na	na	na	During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7(1).	Equipment design and use of natural gas as fuel.

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	401 KAR 51:017	NOX CO VOC PM H2SO4 CO2	See RLSO Permit	na	Operate and maintain an SCR, oxidation catalyst, and operate under a good combustion and operation practices plan	Combust only pipeline natural gas as fuel. CEMS for NOx, CO, and CO2, Stack testing for VOC for PM, PM10, PM2.5 Record month and 12-month rolling emissions of NOx, CO, and VOC from Unit 12 (includes SU/SD)
COMB20, 59	**Auxiliary Steam Boiler**	Boiler MACT: 40 CFR 63.7500(a)	na	na	na	The Permittee shall meet the requirements in 63.7500(a)(1) through (3), except as provided in 63.7500(b) through (e). The Permittee shall meet these requirements at all times the affected unit is operating, except as provided in 63.7500(f).	Meet applicable emission limits and work practice standards.
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7500(a)(1) and 63.7505(a)	na	na	na	The Permittee shall meet each work practice standard in Table 3 to 40 CFR 63, Subpart DDDDD that applies to the boiler or process heater, for each boiler or process heater.	Meet applicable work practice standards.
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7500(a)(3)	na	na	na	Good air pollution control practices for minimizing emissions.	Operate the affected source in a manner consistent with safety and good air pollution control practices.
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7510(g)	na	na	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).	Meet applicable work practice standards.
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7540(a)	na	na	na	The Permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.	Meet applicable work practice standards.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	na	na	na	The Permittee shall conduct an annual (or every 5 years if using continuous oxygen trim system) tune-up of the process heater to demonstrate continuous compliance as specified in 63.7540(a)(10)(i) through (vi). The Permittee shall conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the process heater over the 12 months prior to the tune-up.	Meet applicable work practice standards.
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7540(a)(13)	na	na	na	If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.	Meet applicable work practice standards.
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7505(a); 40 CFR 63.7515(d); 40 CFR Subpart DDDDD Table 3(3);	na	na	na	The Permittee shall conduct an annual performance tune-up according to 63.7540(a)(10). Each annual tune-up specified in 63.7540(a)(10) must be no more than 13 months after the previous tune-up; If continuous oxygen trim system is being used, can conduct tune-up every 5 years instead. Each burner must be inspected once every 36 months. If trim system is utilized on a unit without emission standards, set oxygen level no lower than oxygen concentration measured during most recent tune-up.	Conduct annual tune-up. Or tune-up every 5 years if using continuous oxygen trim system.
COMB20, 59	Auxiliary Steam Boiler	Boiler MACT: 40 CFR 63.7515(d)	na	na	na	The Permittee shall complete a subsequent tune-up by following the procedures from 63.7540(a)(10) and the schedule described in 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.	Follow the described tune-up procedures.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB20, 59	Auxiliary Steam Boiler	401 KAR 59:015. Section 4(1)(b)	PM	0.1 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
COMB20, 59	Auxiliary Steam Boiler	401 KAR 59:015, Section 4(2)	Opacity	20%	na	na	Equipment design and use of natural gas as fuel.
COMB20, 59	Auxiliary Steam Boiler	401 KAR 59:015, Section 5(1)(b)	SO2	0.8 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
COMB20, 59	Auxiliary Steam Boiler	401 KAR 59:015, Section 7; 401 KAR 59:015, Section 7(2)(a)	na	na	na	During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii).	Equipment design and use of natural gas as fuel.
COMB20, 59	Auxiliary Steam Boiler	401 KAR 52:020, Section 10	na	na	4000 hr/yr	The permittee shall limit the hours of operation of EU 59 to no more than 4,000 hours per calendar year	Recordkeeping
COMB20, 59	Auxiliary Steam Boiler	401 KAR 51:017	NOX CO VOC PM H2SO4 CO2e	See RLSO Permit	na	Limit emissions through the use of LNBs and operate under a good combustion and work practices per Boiler MACT.	Combust only pipeline natural gas as fuel for H_2SO_4 and CO_2e. If requested, stack testing for NOx, CO, VOC, PM, PM_{10}, and/or $PM_{2.5}$

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB20, 59	Auxiliary Steam Boiler	NSPS Dc: 40 CFR 60.48c(g)(2)	SO_2	None	na	The owner or operator of an affected facility that combusts only natural gas to demonstrate compliance with the SO2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month	Recordkeeping
COMB21, 60	**Fuel Gas (Dewpoint) Preheater**	Boiler MACT: 40 CFR 63.7500(a)	na	na	na	The Permittee shall meet the requirements in 63.7500(a)(1) through (3), except as provided in 63.7500(b) through (e). The Permittee shall meet these requirements at all times the affected unit is operating, except as provided in 63.7500(f).	Meet applicable emission limits and work practice standards.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7500(a)(1) and 63.7505(a)	na	na	na	The Permittee shall meet each work practice standard in Table 3 to 40 CFR 63, Subpart DDDDD that applies to the boiler or process heater, for each boiler or process heater.	Meet applicable work practice standards.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7500(a)(3)	na	na	na	Good air pollution control practices for minimizing emissions.	Operate the affected source in a manner consistent with safety and good air pollution control practices.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7510(g)	na	na	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).	Meet applicable work practice standards.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7540(a)	na	na	na	The Permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.	Meet applicable work practice standards.

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	na	na	na	The Permittee shall conduct an annual (or every 5 years if using continuous oxygen trim system) tune-up of the process heater to demonstrate continuous compliance as specified in 63.7540(a)(10)(i) through (vi). The Permittee shall conduct the tune-up while burning the type of fuel that provided the majority of the heat input to the process heater over the 12 months prior to the tune-up.	Meet applicable work practice standards.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7540(a)(13)	na	na	na	If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.	Meet applicable work practice standards.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7505(a); 40 CFR 63.7515(d); 40 CFR Subpart DDDDD Table 3(3)	na	na	na	The Permittee shall conduct an annual performance tune-up according to 63.7540(a)(10). Each annual tune-up specified in 63.7540(a)(10) must be no more than 13 months after the previous tune-up; If continuous oxygen trim system is being used, can conduct tune-up every 5 years instead. Each burner must be inspected once every 36 months. If trim system is utilized on a unit without emission standards, set oxygen level no lower than oxygen concentration measured during most recent tune-up.	Conduct annual tune-up. Or tune-up every 5 years if using continuous oxygen trim system.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7515(d)	na	na	na	The Permittee shall complete a subsequent tune-up by following the procedures from 63.7540(a)(10) and the schedule described in 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.	Follow the described tune-up procedures.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB21, 60	Fuel Gas (Dewpoint) Preheater	401 KAR 59:015. Section 4(1)(b)	PM	0.1 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	401 KAR 59:015, Section 4(2)	Opacity	20%	na	na	Equipment design and use of natural gas as fuel.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	401 KAR 59:015, Section 5(1)(b)	SO2	0.8 lb/MMBtu	na	na	Equipment design and use of natural gas as fuel.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	401 KAR 59:015, Section 7; 401 KAR 59:015, Section 7(2)(a)	na	na	na	During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii).	Equipment design and use of natural gas as fuel.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	401 KAR 51:017	NOX CO VOC PM H2SO4 CO2e	See RLSO Permit	na	Limit emissions through the use of LNBs and operate under a good combustion and work practices per Boiler MACT.	Combust only pipeline natural gas as fuel for H_2SO_4 and CO_2e. If requested, stack testing for NOx, CO, VOC, PM, PM_{10}, and/or $PM_{2.5}$
COMB21, 60	Fuel Gas (Dewpoint) Preheater	NSPS Dc: 40 CFR 60.48c(g)(2)	SO_2	None	na	The owner or operator of an affected facility that combusts only natural gas to demonstrate compliance with the SO2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month	Recordkeeping

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4205(b); 60.4202(a)(2); 40 CFR part 1039, appendix I	NMHC + NOx	From 60.4202 referenced in 60.4205, NMHC + NOx shall not exceed 6.4 g/kW-hr (4.8 g/hp-hr) according to Table 2 of 40 CFR 1039 Appendix I over the entire life of the engine.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4205(b); 60.4202(a)(2); 40 CFR part 1039, appendix I	CO	From 60.4202 referenced in 60.4205, CO shall not exceed 3.5 g/kW-hr (2.6 g/hp-hr) according to Table 2 of 40 CFR 1039 Appendix I over the entire life of the engine.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4205(b); 60.4202(a)(2); 40 CFR part 1039, appendix I	PM	From 60.4202 referenced in 60.4205, PM shall not exceed 0.20 g/kW-hr (0.15 g/hp-hr) according to Table 2 of 40 CFR 1039 Appendix I over the entire life of the engine.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4205(b); 60.4202(a)(2); 40 CFR part 1039.105	Opacity	From 60.4202 referenced in 60.4205, exhaust opacity shall not exceed 20 percent during acceleration mode; 15 percent during lugging mode; and 50 percent during the peaks in either mode as described in 40 CFR 1039.105.	na	na	Purchase engine certified to the emission standards and install and configure according to manufacturer's specifications (60.4211(c)).
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4206	na	na	na	The permittee shall operate and maintain stationary CI ICE that achieves the emission standards as required in 40 CFR 60.4204 and 60.4205 over the entire life of the engine.	Operate according to manufacturer's specifications except where noted by the permittee.

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4207(b)	na	na	na	Must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel. i. Overview. Except as specified in § 1090.300(a), diesel fuel must meet the ULSD per-gallon standards of this section. [40 CFR 1090.305(a)] ii. Sulfur standard: Maximum sulfur content of 15 ppm [40 CFR 1090.305(b)] iii. Cetane index or aromatic content. Diesel fuel must meet one of the following standards: [40 CFR 1090.305(c)]	Use only nonroad diesel fuel via 40 CFR 1039.305
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4209(a)	na	na	na	If the permittee operates an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, the permittee shall install a non-resettable hour meter prior to startup of the emergency engine.	If applicable, install a non-resettable hour meter.
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4211(a)(1) through (3)	na	na	na	The permittee shall operate and maintain stationary CI ICE according to manufacturer's instructions, change only those emission-related settings that are permitted by the manufacturer; and meet the requirements of 40 CFR part 1068, as they apply	Operate according to manufacturer's specifications except where noted by the permittee.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4211(c)	na	na	na	The permittee shall purchase an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable, for the same model year and maximum engine power. In addition, the permittee must install and configure the engine according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g).	Purchase an engine certified to the emission standards
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4211(g)	na	na	na	If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance with 40 CFR 60.4211(g)(3).	Comply with 40 CFR 60.4211(g)(3)
COMB22, 61	2.18 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4211(f)	na	na	na	There is no time limit on use of emergency stationary RICE in emergency situations. You may operate your emergency stationary RICE for up to 100 hours per calendar year for maintenance and testing, with 50 hours allowed for specified non-emergency purposes as part of the 100 hours.	Operate generators according to hour limitations for maintenance, non-emergency, etc.
COMB22, 61	2.18 MW Diesel Emergency Generator	RICE MACT: 40 CFR 63.6590(b)(1)	na	na	na	EU 61 does not have to meet the requirements of Subpart ZZZZ and of Subpart A of 40 CFR Part 63 except for the initial notification requirements of 40 CFR 63.6645(f)	Statement of fact

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB22, 61	2.18 MW Diesel Emergency Generator	401 KAR 51:017	NOX + NMHC CO PM CO2e	4.8 g/hr-hr 2.6 g/hp-hr 0.15 g/hp-hr 164 lb/MMBtu See RLSO Permit	na	Operate under a good combustion and work practices per NSPS IIII.	Install and operate a certified engine.
COMB23, 62	**422 HP Diesel Driven Fire Pump**	NSPS IIII: 40 CFR 60.4205(c), 60.4206, Table 4	NMHC + NOx	4.0 g/kW-hr (3.0 g/hp-hr)	na	Emission standard is applicable over the entire life of the engine.	Purchase engine certified to the emission standards and install and configure according to the manufacturer specifications (60.4211(c)).
COMB23, 62	422 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4205(c), 60.4206, Table 4	CO	3.5 g/kW-hr (2.6 g/hp-hr)	na	Emission standard is applicable over the entire life of the engine.	Purchase engine certified to the emission standards and install and configure according to the manufacturer specifications (60.4211(c)).
COMB23, 62	422 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4205(c), 60.4206, Table 4	PM	0.20 g/kW-hr (0.15 g/hp-hr)	na	Emission standard is applicable over the entire life of the engine.	Purchase engine certified to the emission standards and install and configure according to the manufacturer specifications (60.4211(c)).

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB23, 62	422 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4207(b), 401 KAR 51:017	na	na	na	Must use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel. i. Overview. Except as specified in § 1090.300(a), diesel fuel must meet the ULSD per-gallon standards of this section. [40 CFR 1090.305(a)] ii. Sulfur standard: Maximum sulfur content of 15 ppm [40 CFR 1090.305(b)] iii. Cetane index or aromatic content. Diesel fuel must meet one of the following standards: [40 CFR 1090.305(c)]	Use only nonroad diesel fuel via 40 CFR 1039.305
COMB23, 62	422 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4211(a)(1) through (3)	na	na	na	Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions. Change only those emission-related settings that are permitted by the manufacturer. Meet the requirements of 40 CFR parts 89, 94, and/or 1068, as they apply to you.	Maintain records of maintenance conducted on the engine consistent with the operating requirements of 40 CFR 60.4206 and 40 CFR 60.4211(a).
COMB23, 62	422 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4211(c)	na	na	na	The permittee shall purchase an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable, for the same model year and maximum engine power. In addition, the permittee must install and configure the engine according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g).	Purchase an engine certified to the emission standards

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB23, 62	422 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4211(g)	na	na	na	If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance with 40 CFR 60.4211(g)(3).	Comply with 40 CFR 60.4211(g)(3)
COMB23, 62	422 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4211(f)	na	na	na	Operate according to the requirements in (f)(1) through (3) to be considered an emergency stationary ICE.	Monitor hours of operation in emergency and non-emergency service and the reason the engine was in operation during that time.
COMB23, 62	422 HP Diesel Driven Fire Pump	NESHAP ZZZZ: 40 CFR 63.6590(c)	na	na	na	Meet the requirements of NESHAP ZZZZ by complying with NSPS IIII.	Comply with NSPS IIII.
COMB23, 62	422 HP Diesel Driven Fire Pump	401 KAR 51:017	NOX + NMHC CO PM CO2e	3.0 g/hr-hr 2.6 g/hp-hr 0.15 g/hp-hr 164 lb/MMBtu See RLSO Permit	na	Operate under a good combustion and work practices per NSPS IIII.	Install and operate a certified engine.
EQPT21, 63	**Mechanical Draft Cooling Tower (10 Cells)**	401 KAR 59:010, Section 3(1)(a)	VE	The permittee shall not cause, suffer, allow or permit any continuous emission into the open air from a control device or stack associated with any affected facility which is equal to or greater than twenty (20) percent opacity.	na	na	Equipment design (drift eliminators) and proper operation.

Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
EQPT21, 63	Mechanical Draft Cooling Tower (10 Cells)	401 KAR 59:010, Section 3(2)	PM	PM emissions shall not be more than the lbs/hr limit calculated by the equation in 59:010.	na	na	Equipment design (drift eliminators) and proper operation.
EQPT21, 63	Mechanical Draft Cooling Tower (10 Cells)	401 KAR 52:017	PM	na	na	Minimize emissions of PM, PM10, PM2.5 through the use of inherent drift eliminators achieving 0.001% drift loss	Operate and maintain according to the manufacturer's specifications and recommendations at all times.
EQPT21, 63	Mechanical Draft Cooling Tower (10 Cells)	401 KAR 52:020, Section 10	HAP	na	na	The use of chromium-based water treatment chemicals in the cooling tower is prohibited.	Recordkeeping
AREA5, 68	**NGCC Haul Roads**	401 KAR 63:010, Section 3(1)	PM	na	na	The permittee shall not cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished; or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Reasonable precautions shall include, as applicable: 401 KAR 63:010, Section 3(1)(a) through (f).	Monitoring and recordkeeping requirements
AREA5, 68	NGCC Haul Roads	401 KAR 52:020, Section 10, 401 KAR 51:017	PM	na	na	To ensure roadway emissions from truck traffic are minimized, the permittee shall employ a combination of the following to control fugitive dust emissions as outlined in a dust control plan: surface improvements (pavement), watering (good work practice), and/or other control methods as needed, but at least monthly.	Dust Control Plan

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Emission Unit #	Emission Unit Description	Applicable Regulation or Requirement	Pollutant	Emission Limit (if applicable)	Voluntary Emission Limit or Exemption (if applicable)	Operating Requirement or Limitation (if applicable)	Method of Determining Compliance with the Emission and Operating Requirement(s)
AREA5, 68	NGCC Haul Roads	401 KAR 63:010, Section 3(2)	PM	The permittee shall not cause or permit the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate, as determined by Reference Method 22 of Appendix A in 40 C.F.R. Part 60, for: 1) More than five (5) minutes of emission time during any sixty (60) minute observation period; or 2) More than twenty (20) minutes of emission time during any twenty-four (24) hour period	na	na	Testing via Method 22
EQPT22, 64	Turbine Circuit Breaker with 30 lb. SF6 circuit	401 KAR 51:017	GHGs	The permittee shall limit the SF6 leak rate from EU 64 to no more than 0.5 percent of the total charge on an annual average basis	na	na	Recordkeeping requirements
EQPT26, 69	Natural Gas Piping Fugitives	401 KAR 51:017	VOC & GHGs	na	na	The permittee shall conduct weekly auditory, visual, and olfactory inspections for the presence of natural gas leaks from EU 69, and promptly repair any detected leaks.	Recordkeeping requirements
EQPT24, 66	Diesel Storage Tank for Generator (3,733 gal)	401 KAR 51:017	VOCs, H2SO4	na	na	The permittee shall maintain the diesel storage tanks (EU 66 and EU 67) and the sulfuric acid tank (EU70) in good operating condition	na
EQPT25, 67	Diesel Storage Tank for Firewater Pump (300 gal)						
EQPT27, 70	93% Sulfuric Acid Tank						

Section V.2: Monitoring Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Monitored	Description of Monitoring
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NO_X	40 CFR 60.4340(b)(1)	NO_X emissions	Install, calibrate, maintain and operate a continuous emissions monitoring system as described in 40 CFR 60.4335(b) and 40 CFR 60.4345.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NO_X	40 CFR 60.4350	NO_X emissions	Identify excess emissions using the guidelines for CEMS equipment specified in 40 CFR 60.4350(a)-(f) and (h).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	SO_2	40 CFR 60.4360 & 60.4365(a)	Fuel sulfur content	The permittee must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The owner or operator must demonstrate that the fuel used will not exceed potential sulfur emissions of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input and will have a total sulfur content of 20 grains of sulfur or less per 100 standard cubic feet by using fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6125(a)	Catalyst inlet temperature	For each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst, maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6135(a)	Catalyst inlet temperature	Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), the permittee must conduct all parametric monitoring at all times the stationary combustion turbine is operating.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6135(b)	Catalyst inlet temperature	Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. The permittee must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	CO, NO_X, CO_2	401 KAR 51:017 & 52:020, Section 10	CO, NO_X, CO_2 emission rates	Determine compliance monthly by calculating the average CO, NO_X, and CO_2 emission rates for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Monitored	Description of Monitoring
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	CO_2	401 KAR 51:017 & 52:020, Section 10	Gross electric output	As the BACT limit for CO2 is on an output basis (e.g., lb CO2 per gross MWh), the permittee must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output from the affected EGU. These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NO_X	401 KAR 51:017 & 52:020, Section 10	NH_4 injection rate	Install, calibrate at least annually, maintain and operate a device to continuously monitor the rate of ammonia injection in the SCR to ensure that it does not fall outside of the range documented by the manufacturer's specifications or the range determined during the most recent performance test. Ammonia usage must be optimized to minimize ammonia slip.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	na	401 KAR 52:020, Section 10	Operational parameters	Monitor the following: i. The monthly number of cold start, warm start, hot start, and shutdown events; ii. The monthly number of hours in "fired" and "unfired" modes; and iii. The monthly natural gas usage in "fired" and "unfired" modes in MMscf
COMB20, 59	**Auxiliary Steam Boiler**	na	NSPS Dc: 40 CFR 60.48c(g)(2); 401 KAR 52:020, Section 10	NG Usage	The permittee shall monitor hours or operation and natural gas (MMscf) on a monthly basis.
COMB21, 60	**Fuel Gas (Dewpoint) Preheater**	na	NSPS Dc: 40 CFR 60.48c(g)(2); 401 KAR 52:020, Section 10	NG Usage	The permittee shall monitor hours or operation and natural gas (MMscf) on a monthly basis.
COMB22, 61	**2.18 MW Diesel Emergency Generator**	na	401 KAR 52:020, Section 10	Operating Hours	Monitor the amount of fuel (Mgal) used and hours of operation on a monthly basis.
COMB23, 62	**422 HP Diesel Driven Fire Pump**	na	401 KAR 52:020, Section 10	Operating Hours	Monitor the amount of fuel (Mgal) used and hours of operation on a monthly basis.
EQPT21, 63	**Mechanical Draft Cooling Tower (10 Cells)**	PM	401 KAR 52:020, Section 10	TDS	Monitor the total dissolved solids content of the circulating water on a monthly basis.

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Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Monitored	Description of Monitoring
AREA5, 68	NGCC Haul Roads	PM	401 KAR 52:020, Section 10, 401 KAR 63:010, Section 3(1)	na	Monitor actions taken to prevent the discharge of visible fugitive emissions beyond the property line, including the application of wet suppression
AREA5, 68	NGCC Haul Roads	PM	401 KAR 63:010, Section 3(2)	na	Monitor the rate of material hauled (in tons, VMT, gallons/hr, etc.) for each unit or vehicle on the paved roadways on a monthly basis.

Section V.3: Recordkeeping Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NOX	NSPS KKKK: 40 CFR 60.4350(b)	NO_X Emission Rate	For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NOX and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOX emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of 40 CFR 60. For any hour in which the hourly average O2 concentration exceeds 19.0 percent O2 (or the hourly average CO2 concentration is less than 1.0 percent CO2), a diluent cap value of 19.0 percent O2 or 1.0 percent CO2 (as applicable) may be used in the emission calculations.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6125(e)	Catalyst inlet temperature	Since the temperature monitoring system is a continuous monitoring system (CMS), the permittee must develop and implement a CMS quality control program that included written procedures for CMS according to 40 CFR 63.8(d)(1) through (2). The permittee must 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 Division. 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 Division, for a period of 5 years after each revision to the plan. The program of corrective action should be included in the plan required under 40 CFR 63.8(d)(2).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6155(a)	Various	Keep the records as described in 40 CFR 63.6155(a)(1) through (7).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6155(c)	Catalyst inlet temperature	Keep the records required in Table 5 of 40 CFR 63 Subpart YYYY to show continuous compliance with each operating limitation that applies.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6155(d)	na	Any records required to be maintained by this part that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the Division or the EPA as part of an on-site compliance evaluation.

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Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6160	na	Maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection according to 40 CFR 63.10(b)(1). As specified in 40 CFR 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, corrective action, report, or record. The permittee shall retain the records of the most recent 2 years on site or the records shall be accessible on site. The records of the remaining 3 years may be retained off site.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	CO, NO_X, CO_2	401 KAR 51:017 & 52:020, Section 10	CO, NO_X, CO_2 emission rates	Maintain records of CO, NO_X, and CO_2 CEMS data to demonstrate compliance with the applicable limits under 401 KAR 51:017.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	na	401 KAR 52:020, Section 10	Operational parameters	Maintain records of the following: i. The monthly and 12-month rolling number of cold start, warm start, hot start, and shutdown events times the vendor supplied pounds of NOX, CO, and VOC per event; ii. The monthly and 12-month rolling number of hours in “fired” and “unfired” modes; iii. The monthly and 12-month rolling natural gas usage in “fired” and “unfired” modes in MMscf; iv. The hourly NOX and CO CEMS data inclusive of all operational hours and startup and shutdown periods; v. The monthly and 12-month rolling emissions of NOX, CO, and VOC emissions from Unit 12 inclusive of all startup and shutdown events and steady-state operations to demonstrate compliance with the applicable limits under 401 KAR 51:017; vi. The monthly and 12-month rolling average pounds of CO2 emitted on a lb/MWh-g from the NGCC to demonstrate compliance with the applicable limits under 401 KAR 51:017, and vii. The GCOP Plan as well as any revisions to demonstrate compliance with the applicable operational restrictions under 401 KAR 51:017 for PM/PM10/PM2.5, CO, VOC, H2SO4, and GHG emissions.
COMB20, 59	**Auxiliary Steam Boiler**	na	NSPS Dc: 40 CFR 60.48c(g); 401 KAR 52:020, Section 10	Fuel Combusted and hours of operation	Maintain records of hours of operation and fuel combusted during each calendar month by 60.48c(g)(2) and maintain the records for two years following the date of the record by 60.48c(i).
COMB20, 59	Auxiliary Steam Boiler	na	NSPS Dc: 40 CFR 60.48c(i)	na	All records required under 40 CFR 60.48c shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

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Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7555(a)	na	The Permittee shall keep records according to 63.7555(a)(1) and (2).
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7555(h)	Hours of Alternative Fuel Use	If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7560(a)	na	Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 63.10(b)(1).
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7560(b)	na	As specified in 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7560(c)	na	The Permittee shall keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). The Permittee may keep the records off site for the remaining 3 years.
COMB21, 60	**Fuel Gas (Dewpoint) Preheater**	na	NSPS Dc: 40 CFR 60.48c(g); 401 KAR 52:020, Section 10	Fuel Combusted and hours of operation	Maintain records of hours of operation and fuel combusted during each calendar month by 60.48c(g)(2) and maintain the records for two years following the date of the record by 60.48c(i).
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	NSPS Dc: 40 CFR 60.48c(i)	na	All records required under 40 CFR 60.48c shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7555(a)	na	The Permittee shall keep records according to 63.7555(a)(1) and (2).

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Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7555(h)	Hours of Alternative Fuel Use	If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7560(a)	na	Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 63.10(b)(1).
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7560(b)	na	As specified in 63.10(b)(1), the Permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7560(c)	na	The Permittee shall keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 63.10(b)(1). The Permittee may keep the records off site for the remaining 3 years.
COMB22, 61	**2.18 MW Diesel Emergency Generator**	na	NSPS IIII: 40 CFR 60.4214(b); 60.4214(c)	Operating Hours	Records of the hours of operation of the engine in emergency and non-emergency operation if the engine is not certified to meet the non-emergency emissions standards. If the emergency generator engine is equipped with a diesel particulate filter, keep records of any corrective action taken after the backpressure monitor has notified the permittee that the high backpressure limit of the engine is approached.
COMB22, 61	2.18 MW Diesel Emergency Generator	na	401 KAR 52:020, Section 10	Fuel Usage and Operating Hours	Records of the amount of fuel (Mgal) used and hours of operation on a monthly basis.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
COMB23, 62	**422 HP Diesel Driven Fire Pump**	na	NSPS IIII: 40 CFR 60.4214(b)	Operating Hours	Records of the hours of operation of the engine in emergency and non-emergency operation if the engine is not certified to meet the non-emergency emissions standards.
COMB23, 62	422 HP Diesel Driven Fire Pump	na	401 KAR 52:020, Section 10	Fuel Usage and Operating Hours	Records of the amount of fuel (Mgal) used and hours of operation on a monthly basis.
EQPT21, 63	**Mechanical Draft Cooling Tower (10 Cells)**	VE	401 KAR 52:020, Section 10	Processing Rate	Records of the maximum pumping capacity and monthly records of the total dissolved solids content.
EQPT21, 63	Mechanical Draft Cooling Tower (10 Cells)	PM	401 KAR 52:020, Section 10	Processing Rate	Records of the maintenance performed and use of the drift eliminators for the cooling tower. Keep onsite, and in a form suitable and readily available for expeditious review, the manufacturer's specifications for the cooling towers, including the drift rate.
EQPT21, 63	Mechanical Draft Cooling Tower (10 Cells)	HAP	401 KAR 52:020, Section 10	Processing Rate	Records of water treatment chemical purchases, including invoices and other documentation that includes invoices and other documentation that includes date(s) of purchase or shipment, trade name or other information to identify composition of the product, and quantity of the product.
AREA5, 68	**NGCC Haul Roads**	PM	401 KAR 52:020, Section 10	na	Maintain a log of the reasonable precautions taken to prevent particulate matter from becoming airborne on a daily basis. Notation of the operating status, down-time, or relevant weather conditions are acceptable for entry to the log.
AREA5, 68	NGCC Haul Roads	PM	401 KAR 52:020, Section 10	na	Maintain a log of any Reference Method 22 performed and field records identified in Reference Method 22 and any corrective action taken and the results.
EQPT22, 64	**Turbine Circuit Breaker with 30 lb. SF6 circuit**	GHGs	401 KAR 52:020, Section 10	na	The permittee shall maintain records from the leak rate calculations from EU 64 on an annual average.

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Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
EQPT26, 69	Natural Gas Piping Fugitives	VOC & GHGs	401 KAR 52:020, Section 10	na	The permittee shall maintain records for the natural gas leak inspections.

Section V.4: Reporting Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NO_X	NSPS KKKK: 40 CFR 60.4375(a)	NO_X excess emissions	Submit reports of excess emissions and monitor downtime, as defined in 40 CFR 60.4380(b), in accordance with 40 CFR 60.7. Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NO_X	NSPS KKKK: 40 CFR 60.4395; 60.7(c)	NO_X excess emissions	Submit reports of excess emissions to the Division semiannually, except when more frequent reporting is specifically required by an applicable subpart; or the Division, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance of the source. All reports shall be postmarked by the 30th day following the end of each six month period.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NO_X	NSPS KKKK: 40 CFR 60.4380	NO_X excess emissions	For turbines using continuous emission monitoring, periods of excess emissions and monitor downtime that must be reported are defined in 60.4380(b)(1) and (b)(2).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6130(b)	NOCS	To demonstrate initial compliance with the emission and operating limitations, the permittee must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in §63.6145(f).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6140(b)	Deviations	Report each instance in which each emission limitation or operating limitation was not met. Report each instance in which the requirements in Table 7 40 CFR 63 Subpart YYYY that apply were not met. These instances are deviations from the emission and operating limitations 40 CFR 63 Subpart YYYY. These deviations must be reported according to the requirements in 40 CFR 63.6150.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	na	40 CFR 63.6145(a)	na	Submit all of the notifications in 40 CFR 63.7(b) and (c), 63.8(f)(4), and 63.9(b) and (h) that apply by the dates specified.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6145(c)	Initial Notification	The permittee shall submit an Initial Notification not later than 120 calendar days after becoming subject to 40 CFR 63, Subpart YYYY.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	na	40 CFR 63.6145(e)	Initial Performance Test	Submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in 40 CFR 63.7(b)(1).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	na	40 CFR 63.6145(f)	Notification of Compliance	Submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6150(a)	Semiannual Compliance Report	Submit a semiannual compliance report according to Table 6 of 40 CFR 63 Subpart YYYY. The semiannual compliance report must contain the information described in 40 CFR 63.6150 (a)(1) through (5). The semiannual compliance report, including the excess emissions and monitoring system performance reports of 40 CFR 63.10(e)(3), must be submitted by the dates specified in paragraphs (b)(1) through (5) of this section, unless the Division has approved a different schedule. After September 8, 2020, or once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, whichever date is later, you must submit all subsequent reports to the EPA following the procedure specified in 40 CFR 63.6150(g).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6150(b)	Semiannual Compliance Report	The first semiannual report and each subsequent semiannual report shall cover the periods specified in 40 CFR 63.6150(b)(1) and (3), respectively. The first semiannual report and each subsequent semiannual report shall be postmarked or delivered no later than the dates specified in 40 CFR 63.6150(b)(2) and (4), respectively.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6150(b)(5)	Semiannual Compliance Report	For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in 40 CFR 63.6150(b)(1) through (4).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6150(f)	Performance Test Report	Within 60 days after the date of completing each performance test required by 40 CFR 63 Subpart YYYY, submit the results of the performance test (as specified in 40 CFR 63.6145(f)) following the procedures specified in 40 CFR 63.6150(f)(1) through (3).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6150(g)	Report Procedures	The permittee is required to submit reports following the procedure specified in 40 CFR 63.5150(g).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6150(h)	Claim of EPA system Outage	If the permittee is required to electronically submit a report through CEDRI in the EPA's CDX, the permittee may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, the permittee must meet the requirements outlined in 40 CFR 63.6150(h)(1)-(5).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6150(i)	Claim of force majeure	If the permittee is required to electronically submit a report through CEDRI in the EPA's CDX, the permittee may assert a claim of force majeure to timely comply with the reporting requirement. To assert a claim of force majeure, the permittee must meet the requirements outlined in 40 CFR 63.6150(i)(1)-(5).
COMB20, 59	**Auxiliary Steam Boiler**	na	Boiler MACT: 40 CFR 63.7495(d)	na	Meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7530(f)	Notification of Compliance	The Permittee shall submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.7545(e).
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7540(b)	Deviation Report	Report each instance in which an operating limit in Table 3 was not met as a deviation according to 63.7550.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7545(a)	na	The Permittee shall submit to the Division all of the notifications in 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7545(c)	na	As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7545(e)	Notification of Compliance	The Notification of Compliance Status must only contain the information specified in 63.7545(e)(1) and (8) and must be submitted within 60 days of the compliance date specified at 63.7495(b).

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Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7545(f)	na	If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5).
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7545(h)	na	Notification if the permittee switched fuels or made a physical changfe to a boiler and the fuel switch or physical change resulted in the applicability of a different subcategory.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7550(a)	na	The Permittee shall submit each report in Table 9 to 40 CFR 63, Subpart DDDDD that applies to the Permittee.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7550(b)	na	Unless the EPA Administrator has approved a different schedule for submission of reports under 63.10(a), the Permittee shall submit each report, according to 63.7550(h), by the date in Table 9 to 40 CFR 63, Subpart DDDDD and according to the requirements in 63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct subsequent annual tune-ups according to 63.7540(a)(10), and not subject to emission limits or Table 4 operating limits, the Permittee may submit only an annual compliance report, as specified in 63.7550(b)(1) through (4), instead of a semi-annual compliance report.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7550(b)(5)	na	For each affected source that is subject to permitting regulations pursuant to 40 CFR 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 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4).
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7550(c)(1)	Compliance Report	Submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii).
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7550(h)	na	The Permittee shall submit the reports according to the procedures specified in 63.7550(h)(1) through (3).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7495(d)	na	Meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7530(f)	Notification of Compliance	The Permittee shall submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 63.7545(e).
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7540(b)	Deviation Report	Report each instance in which an operating limit in Table 3 was not met as a deviation according to 63.7550.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7545(a)	na	The Permittee shall submit to the Division all of the notifications in 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7545(c)	na	As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7545(e)	Notification of Compliance	The Notification of Compliance Status must only contain the information specified in 63.7545(e)(1) and (8) and must be submitted within 60 days of the compliance date specified at 63.7495(b).
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7545(f)	na	If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5).
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7545(h)	na	Notification if the permittee switched fuels or made a physical changfe to a boiler and the fuel switch or physical change resulted in the applicability of a different subcategory.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7550(a)	na	The Permittee shall submit each report in Table 9 to 40 CFR 63, Subpart DDDDD that applies to the Permittee.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7550(b)	na	Unless the EPA Administrator has approved a different schedule for submission of reports under 63.10(a), the Permittee shall submit each report, according to 63.7550(h), by the date in Table 9 to 40 CFR 63, Subpart DDDDD and according to the requirements in 63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct subsequent annual tune-ups according to 63.7540(a)(10), and not subject to emission limits or Table 4 operating limits, the Permittee may submit only an annual compliance report, as specified in 63.7550(b)(1) through (4), instead of a semi-annual compliance report.
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7550(b)(5)	na	For each affected source that is subject to permitting regulations pursuant to 40 CFR 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 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4).
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7550(c)(1)	Compliance Report	Submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii).
COMB21, 60	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7550(h)	na	The Permittee shall submit the reports according to the procedures specified in 63.7550(h)(1) through (3).
COMB22, 61	**2.18 MW Diesel Emergency Generator**	na	NSPS III: 40 CFR 60.4214(a)	na	The owner or operator is not required to submit an initial notification if the emergency engine is a certified engine.
COMB22, 61	2.18 MW Diesel Emergency Generator	na	NSPS III: 40 CFR 60.4214(b)	na	If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the permittee is not required to submit an initial notification. Starting with the model years in Table 5 to NSPS Subpart IIII, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the permittee 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 permittee must record the time of operation of the engine and the reason the engine was in operation during that time.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB22, 61	2.18 MW Diesel Emergency Generator	na	RICE MACT: 40 CFR 63.6645(f)	Initial Notifications	Submit initial notification in accordance with 40 CFR 63.9(b)(2)(i) through (v) and a statement that stationary RICE has no additional requirements and explain the basis of the exclusion. By 40 CFR 63.6645(c), the initial notification should be submitted no later than 120 days after startup(since 40 CFR 63.6595(a)(3) states startup is when compliance begins).
COMB23, 62	422 HP Diesel Driven Fire Pump	na	na	na	See Section F - Monitoring, Recordkeeping, and Reporting Requirements
AREA5, 68	NGCC Haul Roads	na	na	na	See Section F - Monitoring, Recordkeeping, and Reporting Requirements

Section V.5: Testing Requirements

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Tested	Description of Testing
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	na	40 CFR 60.4400(b)	Initial Performance Test	Perform the initial performance test required under 40 CFR 60.8 as specified by 40 CFR 60.4400(b)(2) and (4) through (6).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	na	40 CFR 60.4405	Initial Performance Test	Perform the initial performance test required under 40 CFR 60.8 in the alternative manner specified by 40 CFR 60.4405(a) through (d).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6110(a)	Initial Performance Test	The permittee must conduct the initial performance tests or other initial compliance demonstrations in Table 4 of NESHAP YYYY that apply within 180 calendar days after the compliance date that is specified for the stationary combustion turbine in 40 CFR 63.6095 and according to the provisions in 40 CFR 63.7(a)(2).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6110(b)	Initial Performance Test	An owner or operator is not required to conduct an initial performance test to determine outlet formaldehyde concentration on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in 40 CFR 63.6110(b)(1) through (b)(5).
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6115	Subsequent Performance Tests	Subsequent performance tests for formaldehyde must be performed on an annual basis as specified in Table 3 of 40 CFR 63 Subpart YYYY.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6120(a)-(b)	Initial and Subsequent Performance Tests	Conduct each performance test in Table 3 of 40 CFR 63 Subpart YYYY that applies.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Tested	Description of Testing
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6120(c)	Initial and Subsequent Performance Tests	Performance tests must be conducted at high load, defined as 100 percent plus or minus 10 percent. After September 8, 2020, performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. The owner or operator may not conduct performance tests during periods of malfunction. The owner or operator must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the owner or operator shall make available to the Division such records as may be necessary to determine the conditions of performance tests.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	Formaldehyde	40 CFR 63.6120(d)	Initial and Subsequent Performance Tests	Conduct three separate test runs for each performance test, and each test run must last at least 1 hour.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	VOC and PM	401 KAR 51:017 & 52:020, Section 10	Initial and Subsequent Performance Tests	Within 60 days after achieving the maximum production rate but no later than 180 days after initial startup of Unit 12, and every 5 years thereafter, the permittee shall perform stack testing for VOC and PM/PM10/PM2.5 emissions from Unit 12 using the following methods: i. Method 18, 25, or 25A or alternate approved method at the outlet of the stack in accordance with an approved test protocol for VOC. ii. 40 CFR 51, Appendix M, Method 201A/202, and 40 CFR 60, Appendix A, Method 5 (or an alternate method as approved by the Division) at the outlet of the stack in accordance with an approved test protocol for filterable and condensable PM.
COMB19, 58	Unit 12 Gas Turbine with HRSG and DB	NO_X, CO, and VOC	401 KAR 51:017 & 52:020, Section 10	NH4 Injection Rate Inlet Catalyst Temperature	Establish a minimum or maximum operating parameter value, or an operating parameter range for each parameter to be monitored for each control device during testing. The permittee shall monitor and record the following parameters: i. The rate of ammonia injection into the SCR, optimized during testing to minimize ammonia slip; ii. The inlet temperature for the oxidation catalyst.
COMB20, 59	**Auxiliary Steam Boiler**	NOX CO VOC PM/PM10/PM2.5	401 KAR 51:017	na	If requested by the Division, initial and subsequent performance testing shall be required per U.E. EPA Reference Methods.

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Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Tested	Description of Testing
COMB21, 60	Fuel Gas (Dewpoint) Preheater	NOX CO VOC PM/PM10/PM2.5	401 KAR 51:017	na	If requested by the Division, initial and subsequent performance testing shall be required per U.E. EPA Reference Methods.
COMB22, 61	2.18 MW Diesel Emergency Generator	NOX+NMHC CO PM/PM10/PM2.5	401 KAR 51:017	na	If requested by the Division, initial and subsequent performance testing shall be required per U.E. EPA Reference Methods.
COMB23, 62	422 HP Diesel Driven Fire Pump	NOX+NMHC CO PM/PM10/PM2.5	401 KAR 51:017	na	If requested by the Division, initial and subsequent performance testing shall be required per U.E. EPA Reference Methods.
AREA5, 68	NGCC Haul Roads	PM	401 KAR 63:010, Section 3(2)	na	If fugitive dust emissions beyond the lot line of the property are observed, conduct Reference Method 22 (visual determination of fugitive emissions) observations per Appendix A of 40 CFR Part 60. In lieu of conducted US EPA Reference Method 22, immediately perform a corrective action which results in no visible fugitive dust emissions beyond the lot line of the property.

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Section V.6: Notes, Comments, and Explanations

Existing permit conditions for New CI Emergency Fire Pump RICE and New Emergency CI RICE cite 40 CFR Part 89 instead of 40 CFR Part 1039 and 40 CFR Part 80 instead of 40 CFR Part 1090. These citations need to be updated by the Division to the appropriate regulatory locations when the Title V permit is amended for this permit action.

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United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 05/31/2025

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.

Facility (Source) Name	State	Plant Code
E.W. Brown Station	KY	001355

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)
Unit 3 (Emission Unit 03)	Yes
Units 5-11 (Emission Units 23-29)	Yes
Unit 12 (Emissions Unit 58) (2025 revision)	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

Facility (Source) Name (from STEP 1) E.W. Brown Station

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.

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Facility (Source) Name (from STEP 1) E.W. Brown Station

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.

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

Facility (Source) Name (from STEP 1) E.W. Brown Station

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

Certification

Read the certification statement, sign, and date.

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: Cynthia Whitaker		
Signature: DocuSigned by: Cindy Whitaker 6193ECDCA946493...		Date: 3/25/2025

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

APPENDIX D. RBLC SEARCH RESULTS

Table D-1.1 Summary of NOx BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted NO_X Limit (w/o DB)	Permitted NO_X Limit (w/ DB)	Units	Averaging Period	Control
AL-0328	Alabama Power Company Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	2	2	ppmvd @ 15% O2	3 Hours	SCR
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	2	N/A	ppmvd @ 15% O2	1 Hour	SCR and DLN combustors. Wet-injection when firing ULSD.
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	2	2	ppmvd @ 15% O2	1 Hour	SCR
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	2		ppmvd @ 15% O2	24 Hours	SCR and DLN combustors. Wet-injection when firing ULSD.
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	2		ppmvd @ 15% O2	24 Hours	SCR and DLN combustors.
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	2		ppmvd @ 15% O2	3 Hours	SCR and DLN. Wet-injection when firing ULSD.
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	2	2	ppmvd @ 15% O2	3 hours	SCR and DLN combustors
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGB	6/19/2023	4,200	MMBtu/hr	2		ppmvd @ 15% O2	3 Hours	SCR and DLN combustors.
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGA	6/19/2023	3,800	MMBtu/hr	0.0085		lb/MMBtu	Not indicated	SCR and DLN combustors.
IN-0371	WABASH VALLEY RESOURCES, LLC	Integrated Gasification Combined Cycle Combustion Turbines	1/11/2024	2292	MMBtu/hr	2		PPMV @15% O2 when combusting > 50% Natural gas	Not indicated	Steam injection/SCR and good combustion practices
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	2		ppmvd @ 15% O2	24 Hours	SCR and DLN combustors.
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	2		ppmvd @ 15% O2	1 Hour	SCR, DLN combustors, good combustion practices
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	2		ppmvd @ 15% O2	3-Hours	SCR and DLN combustors
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	3		ppmvd @ 15% O2	24-Hours	SCR and DLN combustors
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	3		ppmvd @ 15% O2	24-Hours	SCR and DLN combustors
MI-0431	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/26/2018	4,161	MMBtu/hr (each)	2		ppmvd @ 15% O2	24-Hours	SCR and DLN combustors
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	2		ppmvd @ 15% O2	24-Hours	SCR and DLN combustors
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	2		ppmvd @ 15% O2	24-Hours	SCR and DLN combustors
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	2		ppmvd @ 15% O2	24-Hours	SCR and DLN combustors.
MI-0441	LBWL-Erickson Station	EUCTGHRSG1--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	3		ppmvd @ 15% O2	24-hour rolling	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.
MI-0441	LBWL-Erickson Station	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	3		ppmvd @ 15% O2	24-hour rolling	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	2		ppmvd @ 15% O2	24-Hours	SCR, DLN combustors, good combustion practices

Table D-1.1 Summary of NOx BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted NO_X Limit (w/o DB)	Permitted NO_X Limit (w/ DB)	Units	Averaging Period	Control
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	2		ppmvd @ 15% O2	24-Hours	SCR
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	2		ppmvd @ 15% O2	3-Hours	SCR, DLN
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	2		ppmvd @ 15% O2	3-Hours	SCR, DLN, and use of Natural gas as Primary fuel
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	2	2	ppmvd @ 15% O2	1 Hour	SCR and DLN combustors
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	2	2	ppmvd @ 15% O2	24-Hours	DLN, SCR
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	2		ppmvd @ 15% O2	1 Hour	DLN, SCR, wet injection
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	2	2	ppmvd @ 15% O2	1 Hour	DLN. SCR
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	2		ppmvd @ 15% O2	1 Hour	DLN, SCR
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	2	2	ppmvd @ 15% O2	1 Hour	DLN, SCR
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	2		ppmvd @ 15% O2	1 Hour	DLN, SCR
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	2	2	ppmvd @ 15% O2	1 Hour	SCR, DLN, good combustion practice
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	2	2	ppmvd @ 15% O2	Not indicated	SCR, DLN, good combustion practice, low sulfur fuels
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	2		ppmvd @ 15% O2	1 Hour	DLN, SCR, exclusive natural gas
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	2	2	ppmvd @ 15% O2	12 month rolling	DLN, SCR, good combustion and operating practices
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	2	2	ppmvd @ 15% O2	24-Hours	DLN, SCR, Good engineering practices
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	2		ppmvd @ 15% O2	Not indicated	None indicated
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	2		ppmvd @ 15% O2	Not indicated	SCR
TX-0767	Lon C. Hill Power Station	Two 1-on-1 Gas Fired Combustion Turbines	10/2/2015	195	MW	2		ppmvd @ 15% O2	24-Hours	SCR
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	2		ppmvd @ 15% O2	24-Hours	SCR
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	2		ppmvd @ 15% O2	Not indicated	SCR
TX-0788	Neches Station	Four Simple-Cycle Gas-Fired Turbines	3/24/2016	232	MW (each)	9		ppmvd @ 15% O2	Not indicated	DLN combustors, good combustion practices
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	2		ppmvd @ 15% O2	Not indicated	SCR
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	9		ppmvd @ 15% O2	24-Hours	DLN combustors, good combustion practices
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	2		ppmvd @ 15% O2	3-Hours	SCR, DLN

Table D-1.1 Summary of NOx BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted NO_X Limit (w/o DB)	Permitted NO_X Limit (w/ DB)	Units	Averaging Period	Control
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	2		ppmvd @ 15% O2	1-Hour	SCR and DLN burners
TX-0908	Newman Power Station	One Simple-Cycle Gas-Fired Turbine	8/27/2021	230	MW	2.5		ppmvd @ 15% O2	1 Hour	DLN, SCR
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	2	2	ppmvd @ 15% O2	1 Hour	SCR
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	2	2	ppmvd @ 15% O2	1 Hour	SCR, with ammonia injection, DLN
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	2		ppmvd @ 15% O2	1 Hour	SCR, DLN
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	2		ppmvd @ 15% O2	1 Hour	SCR, DLN
KS-0041	HollyFrontier El Dorado Refinery	L3804	10/30/2019	457	MMBtu/hr	25		ppmvd	1-hour rolling	Steam/water injection
MI-0445	Indeck Niles, LLC	FGCTGHRSG	11/26/2019	3,421	MMBtu/hr (each)	2		ppmvd @ 15% O2	24-hour rolling	SCR with DLNB

Table D-1.2 Summary of CO BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted CO Limit (w/o DB)	Permitted CO Limit (w/ DB)	Units	Averaging Period	Control
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	0.0045		lb/MMBtu	24-hr rolling	Oxidation catalyst technology and good combustion practices
AL-0328	Alabama Power Company Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	0.005	-	lb/MMBtu	3 Hours	Oxidation catalyst
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	0.9	1.7	ppmvd @ 15% O2	1 Hour	Oxidation catalyst
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.9	1.7	ppmvd @ 15% O2 (w/ DB) lb/MMBtu (w/o DB)	1 Hour	Oxidation catalyst
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	1	1.6	ppmvd @ 15% O2	3-Hour	Oxidation catalyst
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	1.5	2	ppmvd @ 15% O2	3-Hour	Oxidation catalyst
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	2		ppmvd @ 15% O2	3-Hour	Oxidation catalyst
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGB	6/19/2023	4,200	MMBtu/hr	2		ppmvd @ 15% O2	3-Hour	Oxidation catalyst
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGA	6/19/2023	3,800	MMBtu/hr	2		ppmvd @ 15% O2	3-Hour	Oxidation catalyst and good combustion practices
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	2		ppmvd @ 15% O2	24 Hour Rolling	Catalytic Oxidation and good combustion practices during normal operations, and good combustion practices during startup/shutdown operations.
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	2		ppmvd @ 15% O2	24 Hour Rolling	Catalytic oxidation and good combustion practices.
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	2		ppmvd @ 15% O2	3 Hours	Good combustion practices and oxidation catalyst
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	2		ppmvd @ 15% O2	24-hr rolling	Oxidation catalyst technology and good combustion practices
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	2		ppmvd @ 15% O2	24-hr Avg	Oxidation catalyst and good combustion practices
MI-0455	Midland Cogeneration Ventures	EUCTGHRSG1	2/1/2023	4,198	MMBtu/hr	2	2	ppmvd @ 15% O2	24- Hr rolling average except SU/SD	Oxidation catalyst
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	2		ppmvd @ 15% O2	24-hr Avg	Oxidation catalyst
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	2		ppmvd @ 15% O2	3 Hours	Oxidation catalyst and good combustion practices
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	2		ppmvd @ 15% O2	3 Hours	Oxidation catalyst and use of clean burning fuels (natural gas and ULSD)
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	2	2	ppmvd @ 15% O2	1 Hour	Oxidation catalyst and good combustion practices
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBtu/hr	2	2	ppmvd @ 15% O2	Not indicated	Good combustion controls and oxidation catalyst
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	2		ppmvd @ 15% O2	Hourly avg.	Good combustion controls and oxidation catalyst

Table D-1.2 Summary of CO BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted CO Limit (w/o DB)	Permitted CO Limit (w/ DB)	Units	Averaging Period	Control
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBtu/hr	2	2	ppmvd @ 15% O2	Not indicated	Good combustion controls and oxidation catalyst
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst and good combustion practices as recommended by the manufacturer
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	2	2	ppmvd @ 15% O2	Not indicated	Oxidation catalyst and good combustion practices as recommended by the manufacturer
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	2		ppmvd @ 15% O2	Not indicated	Good combustion practices and oxidation catalyst
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	2	2	ppmvd @ 15% O2	Not indicated	Oxidation catalyst and good combustion practices
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	2		ppmvd @ 15% O2	1 Hour	Oxidation catalyst, combustion controls, exclusive natural gas
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBtu/hr	2	2	ppmvd @ 15% O2	Not indicated	Oxidation catalyst operated at all steady state operation loads and good combustion practices
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	2	2	ppmvd @ 15% O2	Not indicated	Oxidation catalyst, good engineering practice
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
TX-0767	Lon C. Hill Power Station	Two 1-on-1 Gas Fired Combustion Turbines	10/2/2015	195	MW	2		ppmvd @ 15% O2	24-Hour	Oxidation catalyst
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	2		ppmvd @ 15% O2	3-Hour	Oxidation catalyst
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	2		ppmvd @ 15% O2	3-Hour	SCR and DLN burners
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	2		ppmvd @ 15% O2	3-Hour	Oxidation catalyst
TX-0939	Orange County Advanced Power Station	Two 2-on-1 Mitsubishi M501JAC Gas-Fired Turbines	3/13/2023	1215	MW	2		ppmvd @ 15% O2	24-Hr	Oxidation Catalyst and good combustion practices
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	2	2	ppmvd @ 15% O2	Not indicated	Catalytic oxidizer
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst and good combustion practices
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst, good combustion practices
TX-0908	Newman Power Station	One Simple-Cycle Gas-Fired Turbine	8/27/2021	230	MW	3		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	4		ppmvd @ 15% O2	24-hr rolling	Good combustion practices and oxidation catalyst
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	4		ppmvd @ 15% O2	24-hr rolling	Oxidation catalyst and good combustion practices.
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	4		ppmvd @ 15% O2	24-hr rolling	Oxidation catalyst technology and good combustion practices

Table D-1.2 Summary of CO BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted CO Limit (w/o DB)	Permitted CO Limit (w/ DB)	Units	Averaging Period	Control
MI-0441	LBWL-Erickson Station	EUCTGHRSG1--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	4		ppmvd @ 15% O2	24-hr rolling	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices
MI-0441	LBWL-Erickson Station	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	4		ppmvd @ 15% O2	24-hr rolling	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices
MI-0445	Indeck Niles, LLC	FGCTGHRSG	11/26/2019	3,421	MMBtu/hr (each)	4		ppmvd @ 15% O2	24-hour rolling	Oxidation catalyst technology and good combustion practices
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	4		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	4.3		ppmvd @ 15% O2	3-Hour	Clean burners that prevent CO formation
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	4.3		ppmvd @ 15% O2	3-Hour	Clean burning fuel with good combustion
TX-0788	Neches Station	Four Simple-Cycle Gas-Fired Turbines	3/24/2016	232	MW (each)	9		ppmvd @ 15% O2	Not indicated	Good combustion practices
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	15.9	-	lb/hr (w/ DB)	3 Hours	Oxidation catalyst and good combustion practice
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	25		ppmvd @ 15% O2	3-Hour	DLN burners and good combustion practices
KS-0041	HollyFrontier El Dorado Refinery	L3804	10/30/2019	456.5	MMBtu/hr	40		ppmvd @ 15% O2	3-hour rolling	Proper combustion and operation
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	4 2		ppmvd @ 15% O2	1-Hour Annual	Oxidation catalyst

Table D-1.3 Summary of VOC BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted VOC Limit (w/o DB)	Permitted VOC Limit (w/ DB)	Units	Averaging Period	Control
FL-0364	SEMINOLE GENERATING STATION	2-on-1 natural gas combined-cycle unit (GE 7HA.02)	3/21/2018	3,514	MMBtu/hr	1		ppmvd @15% O2 without duct burner firing		Oxidation catalyst
FL-0363	DANIA BEACH ENERGY CENTER	2-on-1 combined cycle unit (GE 7HA)	12/4/2017	4,000	MMBtu/hr	1		ppmvd @15% O2		Clean Fuels
TX-0939	Orange County Advanced Power Station	Two 2-on-1 Mitsubishi M501JAC Gas-Fired Turbines	3/13/2023	1,215	MW	2		ppmvd @15% O2	3-Hours	Oxidation Catalyst and good combustion practices
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	1.4	2.4	ppmvd @ 15% O2 (w/ DB)	Not indicated	Oxidation catalyst and good combustion practices
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	0.7	1.4	ppmvd @ 15% O2	3-Hour	Oxidation catalyst and good combustion practices
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.7	1.6	ppmvd @ 15% O2	Not indicated	Oxidation catalyst
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	0.7	1.8	ppmvd @ 15% O2	1 Hour	Oxidation catalyst and good combustion practices
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	1	1	ppmvd @ 15% O2	Not indicated	Oxidation catalyst and good combustion practices
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	1	1.5	ppmvd @ 15% O2	Not indicated	Oxidation catalyst, water/steam injection (ULSD), and good combustion practices
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	1	1.5	ppmvd @ 15% O2	Not indicated	Catalytic oxidizer
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	1	2	ppmvd @ 15% O2		Oxidation Catalyst and good combustion practices
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBtu/hr	1	2	ppmvd @ 15% O2	Not indicated	Good combustion controls and oxidation catalyst
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	1	N/A	ppmvd @ 15% O2	Not indicated	Oxidation catalyst
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	1		ppmvd @ 15% O2	N/A	Complete combustion
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	1		ppmvd @ 15% O2	N/A (stack test)	Catalytic oxidation and good combustion practices.
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	1		ppmvd @ 15% O2	3 Hour	Oxidation catalyst and good combustion practices
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	1		ppmvd @ 15% O2	hourly ; each CT/HRSG Train	Oxidation catalyst technology and good combustion practices.
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	1		ppmvd @ 15% O2	N/A	Oxidation catalyst and good combustion practices
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	1		ppmvd @ 15% O2	3 Hour	Oxidation catalyst and use of natural gas as primary fuel
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	1		ppmvd @ 15% O2	1 Hour	Good combustion controls and oxidation catalyst

Table D-1.3 Summary of VOC BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted VOC Limit (w/o DB)	Permitted VOC Limit (w/ DB)	Units	Averaging Period	Control
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	1		ppmvd @ 15% O2	Not indicated	Oxidation catalyst and good combustion practices
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	1		ppmvd @ 15% O2	24-Hour	Good combustion practices and oxidation catalyst
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	1		ppmvd @ 15% O2	Not indicated	Oxidation catalyst, combustion controls, exclusive natural gas
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	1		ppmvd @ 15% O2	Not indicated	None indicated
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	1		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	1		ppmvd @ 15% O2	Not indicated	Oxidation catalyst, good combustion practices
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	1		ppmvd @ 15% O2	Not indicated	Oxidation catalyst, good combustion practices
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	1.5	1.9	ppmvd @ 15% O2	Not indicated	Oxidation catalyst, good combustion practices and low sulfur fuels
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	2	1	ppmvd @ 15% O2	Not indicated	Good combustion controls and oxidation catalyst
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	2		ppmvd @ 15% O2	3 Hour	Catalytic oxidation and good combustion practices for normal operations, and good combustion practices for startup/shutdown operations.
TX-0767	Lon C. Hill Power Station	Two 1-on-1 Gas Fired Combustion Turbines	10/2/2015	195	MW	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	2		ppmvd @ 15% O2	Not indicated	Oxidation catalyst
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	2		ppmvd @ 15% O2	3-Hour	Oxidation catalyst
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,198	MMBtu/hr	2.4		ppmvd @ 15% O2	Hourly	Oxidation catalyst
MI-0441	LBWL-Erickson Station	EUCTGHRSG1--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	3		ppmvd @ 15% O2	Hourly	An oxidation catalyst for VOC control and good combustion practices.
MI-0441	LBWL-Erickson Station	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	3		ppmvd @ 15% O2	Hourly	An oxidation catalyst for VOC control and good combustion practices.
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	3.5		ppmvd @ 15% O2	Not indicated	Oxidation catalyst and good combustion practices
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	4		ppmvd @ 15% O2	N/A (stack test)	Oxidation catalyst and good combustion practices
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	4		ppmvd @ 15% O2	Hourly	Oxidation catalyst and good combustion practices
MI-0445	Indeck Niles, LLC	FGCTGHRSG	11/26/2019	3,421	MMBtu/hr (each)	4		ppm ppmvd @15% O2	hourly	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.

Table D-1.3 Summary of VOC BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted VOC Limit (w/o DB)	Permitted VOC Limit (w/ DB)	Units	Averaging Period	Control
MI-0451	MEC NORTH, LLC	EUCTGHRSG	6/23/2022	3,064	MMBtu/hr	2		ppm	Hourly	Oxidation Catalyst and good combustion practices
MI-0452	MEC SOUTH, LLC	EUCTGHRSG	6/23/2022	3,064	MMBtu/hr	2		ppm	Hourly	Oxidation Catalyst Technology and Good Combustion Practices
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGB	6/19/2023	4,200	MMBtu/hr	0.0013		lb/MMBtu	Not indicated	Catalytic oxidation
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	0.0013		lb/MMBtu	Hourly	Oxidation catalyst and good combustion practices
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGA	6/19/2023	3,800	MMBtu/hr	0.0015		lb/MMBtu	Not indicated	Oxidation catalyst
KS-0041	HollyFrontier El Dorado Refinery	L3804	10/30/2019	457	MMBtu/hr	0.0021		lb/MMBtu	3-hour	Proper combustion and operation
AL-0328	Alabama Power Company Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	0.003		lb/MMBtu	3 Hour	Oxidation catalyst
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	0.004		lb/MMBtu	Hourly	Oxidation catalyst and good combustion practices
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	1.5		lb/MMBtu	Not indicated	Oxidation catalyst and good engineering practice

Table D-1.4 Summary of PM BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted PM Limit (w/o DB)	Permitted PM Limit (w/ DB)	Units	Averaging Period	Control
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	0.0025 0.0066		lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Not indicated	Good combustion practices and the use of pipeline quality natural gas, combustion inlet air filter
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	0.003 0.0059		lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Not indicated	Exclusive natural gas, high-efficiency inlet air filters and DLN
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	0.003	0.0039	lb/MMBtu	N/A (stack test)	Low sulfur/carbon fuel and good combustion practices
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	0.0036		lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated	Natural gas or a natural gas and ethane mixture only
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	0.0039	0.0039	lb/MMBtu (w/ DB)	Not indicated	Good combustion practices with use of low ash/sulfur fuels
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	0.0034 0.006		lb/MMBtu (PM_{filt}) lb/MMBtu ($PM_{10,2.5}$)	Hourly max	Low sulfur fuel and good combustion practices
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	0.0037 0.0069		lb/MMBtu (PM_{filt}) lb/MMBtu (PM_{10})	3 Hour	Good combustion practice
VA-0335	Panda Stonewall, LLC	Two Combined Cycle Combustion Turbines	12/18/2020	242	MW	0.0037		lb/MMBtu ($PM_{2.5}$)	Not indicated	Good combustion practices and use of low-sulfur fuels
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	0.0026 0.0042	0.0026 0.0042	lb/MMBtu (PM) lb/MMBtu ($PM_{10,2.5}$)	3 Hour	Good combustion practice
AL-0328	Alabama Power Company Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	0.004	0.004	lb/MMBtu ($PM_{10,2.5}$)	3 Hour	None indicated
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.044 0.0044	0.005 0.005	lb/MMBtu (PM_{10}) lb/MMBtu ($PM_{2.5}$)	Not indicated	Good combustion
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGA	6/19/2023	3,800	MMBtu/hr	0.0049		lb/MMBtu	N/A	Good combustion practice
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	0.0068	0.0049	lb/MMBtu ($PM_{10,2.5}$)	Not indicated	Low sulfur fuel
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	0.005	0.006	lb/MMBtu (PM)	1 Hour	Good combustion practices and use of pipeline quality natural gas
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	0.008		lb/MMBtu ($PM_{2.5}$)	Not indicated	Air filter, use of natural gas, good combustion practices
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	0.0077		lb/MMBtu ($PM_{10,2.5}$)	1 Hour	Good combustion controls
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	0.006		lb/MMBtu ($PM_{10,2.5}$)	Not indicated	Good combustion practices and pipeline quality natural gas
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	0.0073		lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated	Pipeline quality natural gas
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	0.00735		lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated	Good combustion practices and pipeline quality natural gas
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	0.0068		lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated	Good combustion practices and low sulfur fuels
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	0.0068		lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated	Low sulfur fuels and good combustion practices

Table D-1.4 Summary of PM BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted PM Limit (w/o DB)	Permitted PM Limit (w/ DB)	Units	Averaging Period	Control
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	0.0063	0.0063	lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated	None indicated
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	0.0072		lb/MMBtu ($PM,PM_{10,2.5}$)	Not indicated	None indicated
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGB	6/19/2023	4,200	MMBtu/hr	0.0074		lb/MMBtu	N/A	Good combustion practice
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	0.008		lb/MMBtu	3 Hour	Good combustion practices and clean burning fuels (natural gas)
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	0.008		lb/MMBtu	N/A (stack test)	Use of gaseous fuel (pipeline-quality natural gas) and good combustion practices.
KS-0041	HollyFrontier El Dorado Refinery	L3804	10/30/2019	456.5	MMBtu/hr	0.0066		lb/MMBtu	3-hour rolling	Proper combustion and operation
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	2		gr S/100 scf fuel	N/A (recordkeeping)	Use of clean (low sulfur) fuels
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	2		gr S/100 scf fuel	N/A (recordkeeping)	Clean fuels
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	12.2		lb/hr ($PM_{filt,10,2.5}$)	Not indicated	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	34.4		lb/hr ($PM_{filt,10,2.5}$)	Hourly max	Use of pipeline quality natural gas and good combustion practices
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	8.9 17.9		lb/hr (PM_{filt}) lb/hr ($PM_{10,2.5}$)	3 Hour N/A (stack test)	Exclusive Use of Pipeline-Quality Natural Gas and Good Combustion Practices
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	9.9 19.8		lb/hr (PM_{filt}) lb/hr ($PM_{10,2.5}$)	N/A (stack test)	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	5.8 19.1		lb/hr (PM_{filt}) lb/hr ($PM_{10,2.5}$)	Not indicated	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	4.4 11.4		lb/hr (PM_{filt}) lb/hr ($PM_{10,2.5}$)	N/A (stack test)	Use of natural gas as a clean burning fuel
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	9.3 11.58		lb/hr (PM_{filt}) lb/hr ($PM_{10,2.5}$)	N/A (stack test)	Use of natural gas and ULSD as clean burning fuels
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	9.73	N/A	lb/hr ($PM_{2.5}$)	Not indicated	None indicated
MI-0431	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/26/2018	4,161	MMBtu/hr (each)	10.7		lb/hr ($PM_{10,2.5}$)	Hourly max	Use of clean fuel (natural gas) and good combustion practices
TX-0767	Lon C. Hill Power Station	Two 1-on-1 Gas Fired Combustion Turbines	10/2/2015	195	MW	16		lb/hr ($PM_{10,2.5}$)	Not indicated	Good combustion practices and use of pipeline quality natural gas
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	21.4		lb/hr ($PM_{10,2.5}$)	Not indicated	None indicated

Table D-1.4 Summary of PM BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted PM Limit (w/o DB)	Permitted PM Limit (w/ DB)	Units	Averaging Period	Control
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	19.35		lb/hr ($PM_{10,2.5}$)	Not indicated	Good combustion practices, low sulfur fuel
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	35.47		lb/hr ($PM_{10,2.5}$)	Not indicated	Good combustion practices, low sulfur fuel
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	11.07		lb/hr ($PM_{10,2.5}$)	Not indicated	DLN burners, good combustion practices, pipeline quality sweet natural gas
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	18.2		lb/hr (PM)	Not indicated	Air filter, use of natural gas, good combustion practices
MI-0445	Indeck Niles, LLC	FGCTGHRSG	11/26/2019	3,421	MMBtu/hr (each)	19.8		lb/hour	Not indicated	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.

Table D-1.5 Summary of H2SO4 BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted H_2SO_4 Limit (w/o DB)	Permitted H_2SO_4 Limit (w/ DB)	Units	Averaging Period	Control
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	0.062		gr S/100 scf fuel	N/A (recordkeeping)	Use of gaseous fuel (pipeline-quality natural gas) and good combustion practices
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	1		gr S/100 scf fuel	Not indicated	Pipeline quality natural gas
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	2		gr S/100 scf fuel	N/A (recordkeeping)	Use of clean (low sulfur) fuels
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	2		gr S/100 scf fuel	N/A (recordkeeping)	Use of clean (low sulfur) fuels
TX-0788	Neches Station	Four Simple-Cycle Gas-Fired Turbines	3/24/2016	232	MW (each)	1 0.25		gr S/100 scf fuel	1-Hour Annual	Good combustion practices, low sulfur fuel
TX-0788	Neches Station	Four 1-on-1 Simple Cycle Combustion Turbines	3/24/2016	232	MW	1 0.25		gr S/100 scf fuel	1-Hour Annual	Good combustion practices, low sulfur fuel
TX-0789	Decordova Steam Electric Station	Two 1-on-1 Combustion Turbine	3/8/2016	231	MW	5 1		gr S/100 scf fuel	1-Hour Annual	Good combustion practices, low sulfur fuel
MI-0445	Indeck Niles, LLC	FGCTGHRSG	11/26/2019	3,421	MMBtu/hr (each)	4.6		lb/hour	Hourly	Good combustion practices and the use of pipeline quality natural gas.
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	1		lb/hr	Hourly max	Use of clean fuel (natural gas) with a fuel sulfur limit of 0.8 gr S/100scf
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	2.11	N/A	lb/hr	Not indicated	Use of inherently low sulfur fuel
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	2.3		lb/hr	3 Hour	Controls not feasible for NG. Use of ultra-low sulfur diesel only.
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	2.7		lb/hr	Hourly max	Good combustion practices and the use of pipeline quality natural gas
NJ-0088	Cogen Tech Linden Venture, LP	One 1-on-1 GE 7F.05 Combustion Turbine	7/30/2019	250	MW (each)	3.45		lb/hr	N/A (stack test)	Use of natural gas as a clean burning fuel
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	3.61		lb/hr	N/A (stack test)	Use of natural gas as a clean burning fuel
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	4.6		lb/hr	3 Hour	Initial and annual performance test using EPA Method 8 or equivalent
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGA	6/19/2023	3,800	MMBtu/hr	0.0004		lb/MMBtu	Not indicated	Use of pipeline-quality natural gas
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	0.0005	0	lb/MMBtu	Not indicated	Low sulfur content fuel
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	0.0005		lb/MMBtu	Not indicated	Use of low sulfur fuel
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	0.00053	0.0006	lb/MMBtu	Not indicated	Low sulfur fuel
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	6.50E-04	6.50E-04	lb/MMBtu	1 Hour	Use of natural gas with a fuel sulfur limit of 0.4 gr S/100scf
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	0.0008		lb/MMBtu	Not indicated	Use of natural gas
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	0.0009		lb/MMBtu	Not indicated	Exclusive natural gas
PA-0311	Moxie Freedom Generation Plant	Two 1-on-1 Combustion Turbine	9/1/2015	1,050	MW	0.0009	0.0009	lb/MMBtu	Not indicated	None indicated
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	0.0009		lb/MMBtu	Not indicated	Use of natural gas

Table D-1.5 Summary of H2SO4 BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity [1]	Capacity Units	Permitted H_2SO_4 Limit (w/o DB)	Permitted H_2SO_4 Limit (w/ DB)	Units	Averaging Period	Control
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	0.00102		lb/MMBtu	Not indicated	Good combustion practices and pipeline quality natural gas
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	0.0011	0.0011	lb/MMBtu	Not indicated	Low sulfur fuel
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	0.0011	0.0011	lb/MMBtu	Not indicated	Low sulfur fuel
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	0.0011		lb/MMBtu	Not indicated	Pipeline quality natural gas with sulfur limit of 0.5 gr/100 scf
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	0.0011	0.0011	lb/MMBtu	Not indicated	Natural gas or a natural gas and ethane mixture only
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGB	6/19/2023	4,200	MMBtu/hr	0.0013		lb/MMBtu	Not indicated	Use of pipeline-quality natural gas
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	0.0013		lb/MMBtu	Hourly max	Good combustion practices and the use of pipeline quality natural gas
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	0.0013		lb/MMbtu	Hourly max	Use of clean fuel (natural gas) with a fuel sulfur limit of 1 gr S/100scf
PA-0310	CPV Fairview Energy Center	One 2-on-1 Combined Cycle Turbines	9/2/2016	3,338	MMBTu/hr	0.0014	0.0014	lb/MMBtu	Not indicated	Low sulfur fuels and good combustion practices (NG). Water/steam injection (ULSD)
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	0.0017		lb/MMBtu	1 Hour	Low sulfur fuels
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	0.0006	0.0006	lb/MMBtu (w/ DB)	Not indicated	Low sulfur fuel and good combustion practice
PA-0307	York Energy Center	Two Combined Cycle Combustion Turbines	6/15/2015	835	MW	0.0011	0.0011	lb/MMBtu (w/ DB)	Not indicated	None indicated
PA-0319	Renaissance Energy Center	Two Natural Gas-fired Combustion Turbines	8/27/2018	1,127	MW	5.98		tpy	Not indicated	None indicated
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	10.4		tpy	Not indicated	Low sulfur fuel

[1] Capacity for combined-cycle turbines includes the HRSG but excludes duct burners, if present.

Table D-1.6 CO_2 BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted CO_2 Limit (w/o DB)	Permitted CO_2 Limit (w/ DB)	Units	Averaging Period	Control
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGA	6/19/2023	3,800	MMBtu/hr	726		lb/MWh-gross	12-mo Rolling	None indicated
OH-0375	Long Ridge Energy Generation LLC - Hannibal Power	One 1-on-1 Combustion Turbines	11/7/2017	485	MW	775	775	lb/MWh	12-mo Rolling	High efficiency combustion practices as recommended by the manufacturer
MI-0435	Belle River Power Plant	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/16/2018	1,150	MW (total)	794		lb/MWh	12-mo Rolling	Energy efficiency measures
MI-0423	Indeck Niles, LLC	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	1/4/2017	4,161	MMBtu/hr (each)	802		lb/MWh	Not indicated	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0433	MEC North & MEC South	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	6/29/2019	500	MW (each)	806		lb/MWh	12-mo Rolling	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas)
CT-0158	CPV Towantic Energy Center	Two 1-on-1 GE 7HA.01 Combined-Cycle Gas-Fired Turbines	11/30/2015	805	MW (total)	809	N/A	lb/MWh	12-mo Rolling	None indicated
CT-0161	Lake Road Energy Center	Three 1-on-1 ABB GT-24 Combined-Cycle Gas-Fired Turbines	6/30/2017	550	MW (total)	816	N/A	lb/MWh-net	12-mo Rolling	Use of low carbon fuel
VA-0325	Greensville Power Station	Three 3-on-1 Combustion Turbines	6/17/2016	1,600	MW	812-890	812-890	lb/MWh	Annual (1-6 yrs to > 30-yrs)	None indicated
IN-0365	Maple Creek Energy LLC	Combined Cycle Turbine CTGB	6/19/2023	4,200	MMBtu/hr	826		lb/MWh-gross	12-mo Rolling	None indicated
WV-0029	Harrison County Power Plant	GE 7HA.02 Combined Cycle Combustion Turbine	3/27/2018	3496.2	MMBTu/hr	826		lb/MWh	Not indicated	Use of natural gas and GE7HA
WV-0032	Brooke County Power Plant	Two GE 7HA.01 Combined Cycle Combustion Turbines	9/18/2018	2737.7	MMBTu/hr	829	829	lb/MWh	Not indicated	Use of natural gas and GE7HA
OH-0366	Clean Energy Future - Lordstown, LLC	One 1-on-1 Combined-Cycle Combustion Turbine	8/25/2015	2725	MMBTu/hr	833	833	lb/MWh	Not indicated	High efficient combustion technology
OH-0372	Oregon Energy Center	One 1-on-1 Combined-Cycle Combustion Turbine	9/27/2017	3055	MMBTu/hr	833	833	lb/MWh	Not indicated	High efficiency combustion design
OH-0374	Guernsey Power Station LLC	Three 1-on-1 Combined-Cycle Gas-Fired Turbine	10/23/2017	1650	MW	846	1000	lb/MWh	12-mo Rolling	High efficiency combustion practices as recommended by the manufacturer
FL-0356	Okeechobee Clean Energy Center	3-on-1 GE 7HA.02 Combined-Cycle Gas-Fired Turbines	3/9/2016	1,600	MW (total)	850		lb/MWh (CO_2e)	12-mo Rolling	Use of low-emitting fuels and technologies. ULSD limited to 500 hr/yr.

Table D-1.6 CO_2 BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted CO_2 Limit (w/o DB)	Permitted CO_2 Limit (w/ DB)	Units	Averaging Period	Control
MD-0045	Mattawoman Energy Center	Two Siemens SGT-8000H Combined-Cycle Gas-Fired Turbines	11/13/2015	286	MW (each)	865		lb/MWh	12-mo Rolling	None indicated
FL-0367	Shady Hills Energy Center	1-on-1 GE 7HA Combined-Cycle Gas-Fired Turbine	7/27/2018	573	MW	875		lb/MWh	12-mo Rolling	Low-emitting fuel
LA-0391	Magnolia Power Generating Station	1-on-1 Combined-Cycle Gas-Fired Turbine	6/3/2022	730	MW (total)	875		lb/MWh	Ann. Average	Use of gaseous fuel (pipeline-quality natural gas), thermally efficient turbines, and good combustion practices.
PA-0315	Hilltop Energy Center, LLC	One 1-on-1 Combined cycle combustion turbine	4/12/2017	3,509	MMBTu/hr	879		lb/MWh-gross	Not indicated	None indicated
TX-0834	Montgomery County Power Station	Two Mitsubishi M501GAC Combined-Cycle Turbines	3/30/2018	2,635	MMBtu/hr (each)	884		lb/MWh	Not indicated	Pipeline quality natural gas and good combustion practices
TX-0773	FGE Eagle Pines Project	Three 2-on-2 Gas Fired Turbine	11/4/2015	321	MW	886		lb/MWh	Not indicated	Low carbon fuel, good combustion practices, efficient combined cycle design
NJ-0085	Middlesex Energy Center	One Combined-Cycle Combustion Turbine	7/19/2016	380	MW	888	888	lb/MWh-gross	12-mo Rolling	Use of natural gas as a clean burning fuel
TX-0819	Gaines County Power Plant	2-on-1 Simple-Cycle Combustion Turbines	4/28/2017	426	MW	960		lb/MWh	Not indicated	Pipeline quality natural gas
AL-0328	Alabama Power Company Plant Barry	Two (2) 1-on-1 Combined-Cycle Gas-Fired Turbines	11/9/2020	744	MW (each)	1000	1000	lb/MWh	Not indicated	Efficient design
IL-0130	Jackson Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	12/31/2018	3,864	MMBtu/hr	1000	1000	lb/MWh-gross	12-mo Rolling	Equipment design and proper operation
LA-0313	St. Charles Power Station	2-on-1 Combined-Cycle Gas-Fired Turbines	8/31/2016	980	MW	1000		lb/MWh	Not indicated	Thermally efficient combustion turbines and good combustion practices
MI-0441	LBWL-Erickson Station	EUCTGHRSG1--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	1,000		lb/MWH	12-mo Rolling	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.
MI-0441	LBWL-Erickson Station	EUCTGHRSG2--A 667 MMBTU/H natural gas fired CTG with a HRSG.	12/21/2018	667	MMBtu/hr	1,000		lb/MWH	12-mo Rolling	An oxidation catalyst for VOC control for each CTG/HRSG unit, good combustion practices.
MI-0455	Midland Cogeneration Ventures	Combined-cycle combustion turbines	2/1/2023	4,197.60	MMBtu/hr	1,000		lb/MWh	12-mo Rolling	Low carbon fuel, good combustion practices, energy efficiency measures
OH-0377	Harrison Power	Two Combustion Turbines	4/19/2018	1000	MW	1000		lb/MWh	12-mo Rolling	High efficiency combustion technology
NY-0103	Cricket Valley Energy Center	Turbines and Duct Burners	2/3/2016	228	MW (each)	7,604		BTU/kWh	Not indicated	Good combustion practices and use of natural gas

Table D-1.6 CO_2 BACT Determination for NGCC

RBLC ID	Facility	Process	Permit Date	Capacity	Capacity Units	Permitted CO_2 Limit (w/o DB)	Permitted CO_2 Limit (w/ DB)	Units	Averaging Period	Control
OH-0367	South Field Energy LLC	One 1-on-1 Combined-Cycle Combustion Turbine	9/23/2016	1150	MW	481,301		lb/hr	Hourly max	High efficient combustion technology
TX-0790	Port Arthur LNG Export Terminal	Four GE 7F Refrigeration and Compression Turbines	2/17/2016	10	Mton/yr	504,514		tpy		Good combustion practices and use of low carbon fuel
MI-0427	Filer City Station	One 1-on-1 Combined-Cycle Gas-Fired Turbine	11/17/2017	1,935	MMBtu/hr	992,286		tpy	12-mo Rolling	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0432	New Covert Generating Facility	Three 1-on-1 Mitsubishi 501G Combined-Cycle Gas-Fired Turbines	7/30/2018	1,230	MW (total)	1,425,081		tpy	12-mo Rolling	
PA-0309	Lackawanna Energy Center	One 3-on-1 Combined Cycle Turbines	12/23/2015	1,500	MW	1,629,115		tpy	Not indicated	None indicated
PA-0306	Westmoreland Generating Facility	One 2-on-1 Combined Cycle Turbine	2/12/2016	930-1065	MW	1,881,905		tpy	Not indicated	Good combustion practices
MI-0445	Indeck Niles, LLC	FGCTGHRSG	11/26/2019	3,421	MMBtu/hr (each)	1911481		ton	tpy	Good combustion practices, inlet air conditioning, and the use of pipeline quality natural gas.
MI-0442	Thomas Township Energy, LLC	Two Combined-cycle Gas-Fired Turbine Generators	8/21/2019	625	MW (each)	2,793,722		tpy	12-mo Rolling	Energy efficiency measures
IL-0129	CPV Three Rivers Energy Center	Two 1-on-1 Combined-Cycle Gas-Fired Turbines	7/30/2018	1,200	MW (total)	4,026,300		tpy	12-mo Rolling	Equipment design and proper operation

Table D-2.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Carbon Monoxide	100	MMBTU/H	0.0037	LB/MMBTU		Oxidation Catalyst and operate and maintain boiler according to
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Carbon Monoxide	48.2	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Carbon Monoxide	17.7	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
MD-0042	WILDCAT POINT GENERATION FACILITY	AUXILLARY BOILER	04/08/2014	Carbon Monoxide	45	MMBTU/H	0.036	LB/MMBTU	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Carbon Monoxide	90.5	MMBtu/hr	0.037	LB/MMBTU		
IL-0129	CPV THREE RIVERS ENERGY CENTER	Auxiliary Boiler	07/30/2018	Carbon Monoxide	96	mmBtu/hr	0.037	LB/MMBTU	3-HOUR AVERAGE	Good combustion practices
IL-0130	JACKSON ENERGY CENTER	Auxiliary Boiler	12/31/2018	Carbon Monoxide	96	mmBtu/hr	0.037	LB/MMBTU	3-HOUR	Good combustion practice
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Carbon Monoxide	80	mmBtu/hour	0.037	POUNDS/MMBTU	ROLLING 3-OPERATING HOUR	Good burner design and good combustion practices.
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Carbon Monoxide	96	MMBtu per hour	0.037	LB PER MMBTU	BASED ON A 3-HR AVERAGE	
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Carbon Monoxide	42	MMBTU/H	0.037	LB/MMBTU	3-HOUR BLOCK AVERAGE	GOOD COMBUSTION PRACTICES
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Carbon Monoxide	80	MMBTU/H	0.037	LB/MMBTU	HOURLY; EACH BOILER	Good combustion practices
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Carbon Monoxide	13.31	MMBtu/hr	0.037	LB/MMBTU		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Carbon Monoxide	92.4	MMBtu/hr	0.037	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	ULSD and good combustion practices
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Carbon Monoxide	55.4	MMBtu/hr	0.037	LB/MMBTU		
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	boiler	12/19/2014	Carbon Monoxide	80	MMBTU/H	0.037	LB/MMBTU	3-HR ROLLING AVERAGE	low-NOx burners
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Carbon Monoxide	60	MMBTU/H	0.0375	LB/MMBTU	1 H	good combustion practice
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	Boiler No. 2	05/21/2019	Carbon Monoxide	0		0.0375	LB/MMBTU		Work Practice Standards

Table D-2.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	Auxiliary Boiler	07/16/2014	Carbon Monoxide	25.06	MMBtu/h	0.0375	LB/MMBTU	3 HOUR AVERAGE	good combustion
OR-0050	TROUTDALE ENERGY CENTER, LLC	Auxiliary boiler	03/05/2014	Carbon Monoxide	39.8	MMBTU/H	0.04	LB/MMBTU	3-HR BLOCK AVERAGE	Utilize Low-NOx burners and FGR.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Carbon Monoxide	14.67	MMBTU/H	0.04	LB/MMBTU	HEAT INPUT	Shall be operated for no more than 500 hours and combust
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Carbon Monoxide	80	mm BTU/h	0.05	LB/MM BTU		Good combustion practices; compliance with 40 CFR 63
*PA-0319	RENAISSANCE ENERGY CENTER	NATURAL GAS FIRED AUXILIARY BOILER	08/27/2018	Carbon Monoxide	88	MMBtu/hr	0.055	LB/MMBTU	HR	Lo-NOx burners, Flue Gas Recirculation, good combustion
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Carbon Monoxide	62.04	MCF/hr	0.06	LB/MMBTU		Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Carbon Monoxide	50.4	MMBTU/hr	0.075	LB/MMBTU		Good combustion practices
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Carbon Monoxide	99.9	MMBTU/H	0.075	LB/MMBTU	HOURLY	Good combustion practices
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Carbon Monoxide	83.5	MMBTU/H	0.077	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG	Good combustion practices.
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Carbon Monoxide	17.5	MMBTU/H	0.08	LB/MMBTU		GCP
AL-0307	ALLOYS PLANT	2 CALP LINE BOILERS	10/09/2015	Carbon Monoxide	24.59	MMBTU/H	0.08	LB/MMBTU		GCP
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Auxiliary Boiler, 99.8 MMBtu/hr	03/09/2016	Carbon Monoxide	99.8	MMBtu/hr	0.08	LB/MMBTU		Proper combustion prevents CO
FL-0363	DANIA BEACH ENERGY CENTER	99.8 MMBtu/hr auxiliary boiler	12/04/2017	Carbon Monoxide	99.8	MMBtu/hr	0.08	LB/MMBTU		Clean fuel
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Carbon Monoxide	60	MMBtu/hour	0.08	LB/MMBTU		Good combustion practices and low-NOx burners
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Carbon Monoxide	60	MMBtu/hour	0.08	LB/MMBTU		Good combustion practices and low-NOx burners
MD-0046	KEYS ENERGY CENTER	AUXILIARY BOILER	10/31/2014	Carbon Monoxide	93	MMBTU/H	0.08	LB/MMBTU	3-HOUR BLOCK AVERAGE	EFFICIENT BOILER DESIGN AND APPLICATION OF GOOD
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Carbon Monoxide	6	MMBTU/H	0.08	LB/MMBTU	TEST PROTOCOL	Good combustion practices and clean burn fuel (pipeline quality
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Carbon Monoxide	61.5	MMBTU/H	0.08	LB/MMBTU	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Carbon Monoxide	61.5	MMBTU/h	0.08	LB/MMBTU	HOURLY	Good combustion practices.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Carbon Monoxide	61.5	MMBTU/H	0.08	LB/MMBTU	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Carbon Monoxide	61.5	MMBTU/H	0.08	LB/MMBTU	HOURLY	Good combustion practices.
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Carbon Monoxide	53.7	MMBTU/HR	0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE

Table D-2.1 Summary of CO BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Carbon Monoxide	53.7	MMBTU/HR	0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Carbon Monoxide	53.7	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Carbon Monoxide	53.7	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Carbon Monoxide	53.7	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Carbon Monoxide	15	MMBTU/hr each	0.084	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Carbon Monoxide	0		0.084	LB/MMBTU		Good Combustion Practice

Table D-2.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Volatile Organic Compounds (VOC)	80	mmBtu/hour	0.0015	LB/MMBTU	3-hour	Good burner design and good combustion practices
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Volatile Organic Compounds (VOC)	60	MMBTU/H	0.0015	LB/MMBTU	1 H	good combustion practice
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Volatile Organic Compounds (VOC)	100	MMBTU/H	0.0027	LB/MMBTU		Oxidation catalyst and operate and maintain boiler according to manufacturer's recommendations
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Volatile Organic Compounds (VOC)	42	MMBTU/H	0.003	LB/MMBTU	3-Hour Block Average	Exclusive Use Of Natural Gas, And Good Combustion Practices
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Volatile Organic Compounds (VOC)	96	MMBtu per hour	0.0034	lb/MMBtu	3-hour	Good burner design and good combustion practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Volatile Organic Compounds (VOC)	28	mmBTU	0.0036	LB/MMBTU		Ultra-Low NOx Burners, Flue Gas Recirculation, and Good
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Volatile Organic Compounds (VOC)	90.5	MMBtu/hr	0.004	LB/MMBTU		
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Volatile Organic Compounds (VOC)	61.5	MMBTU/H	0.004	LB/MMBTU	Hourly	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Volatile Organic Compounds (VOC)	61.5	MMBTU/h	0.004	LB/MMBTU	Hourly	Good combustion practices.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Volatile Organic Compounds (VOC)	61.5	MMBTU/H	0.004	LB/MMBTU	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Volatile Organic Compounds (VOC)	61.5	MMBTU/H	0.004	LB/MMBTU	HOURLY	Good combustion practices
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Volatile Organic Compounds (VOC)	62.04	MCF/hr	0.004	LB/MMBTU		Good combustion practices and FGR
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Volatile Organic Compounds (VOC)	92.4	MMBtu/hr	0.004	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	ULSD and good combustion practices
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Volatile Organic Compounds (VOC)	13.31	MMBtu/hr	0.005	LB/MMBTU	30-DAY ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Volatile Organic Compounds (VOC)	55.4	MMBtu/hr	0.005	LB/MMBTU		
*PA-0316	RENOVO ENERGY CENTER, LLC	Auxiliary Boiler	01/26/2018	Volatile Organic Compounds (VOC)	118800	MMBtu/12 month period	0.005	LB	MMBTU	
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Volatile Organic Compounds (VOC)	50	MMBTU/H	0.0054	LB/MMBTU	3-Hr Avg	
AL-0312	BELK CHIP-N-SAW FACILITY	60 MMBTU/HR NATURAL GAS-FIRED BOILER (ES-008)	05/26/2016	Volatile Organic Compounds (VOC)	60	MMBTU/H	0.0054	LB/MMBTU INPUT		Good Combustion Practices
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Volatile Organic Compounds (VOC)	53.7	MMBTU/HR	0.0054	LB/MMBTU		Combustion Of Natural Gas And Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Combustion Of Natural Gas And Good Combustion Practice

Table D-2.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Combustion Of Natural Gas And Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Volatile Organic Compounds (VOC)	53.7	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Volatile Organic Compounds (VOC)	53.7	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Volatile Organic Compounds (VOC)	53.7	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Volatile Organic Compounds (VOC)	50	MMBtu/hr	0.0054	LB/MMBTU		good combustion practices and natural gas fuel (clean fuel)
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Volatile Organic Compounds (VOC)	80	mm BTU/h	0.0054	LB/MM BTU		Good combustion practices; compliance with 40 CFR 63 Subpart DDDDD.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Volatile Organic Compounds (VOC)	80	MMBTU/H	0.0054	LB/MMBTU	HOURLY; EACH BOILER	Good combustion practices.
SC-0192	CANFOR SOUTHERN PINE - CONWAY MILL	Boiler No. 2	05/21/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Work Practice Standards
TX-0877	SWEENY REFINERY	Isostripper Reboiler (heater)	01/08/2020	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Good combustion practices, use of natural gas fuel for the project heater
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Volatile Organic Compounds (VOC)	15	MMBTU/hr each	0.0055	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Volatile Organic Compounds (VOC)	0		0.0055	LB/MMBTU		Good Combustion Practice
WI-0266	GREEN BAY PACKAGING, INC. - SHIPPING CONTAINER DIVISION	Natural gas-fied boiler (Boiler B01)	09/06/2018	Volatile Organic Compounds (VOC)	35	mmBtu/hr	0.0055	LB/MMBTU		Good combustion practices, use only natural gas, equip boiler with Low NOx burners and flue gas recirculation
WI-0289	GEORGIA-PACIFIC CONSUMER PRODUCTS LLC	B98 & B99 Natural Gas Fired Temporary Boilers	04/01/2019	Volatile Organic Compounds (VOC)	95	mmBTU/hr	0.0055	LB/MMBTU		Good Combustion Practices
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Volatile Organic Compounds (VOC)	8.5	MMBtu/H	0.0055	LB/MMBTU		
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Volatile Organic Compounds (VOC)	17.5	MMBTU/H	0.006	LB/MMBTU		GCP
AL-0307	ALLOYS PLANT	2 CALP LINE BOILERS	10/09/2015	Volatile Organic Compounds (VOC)	24.59	MMBTU/H	0.006	LB/MMBTU		GCP
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Volatile Organic Compounds (VOC)	83.5	MMBTU/H	0.008	LB/MMBTU	Test Protocol Will Specify Avg Time	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Volatile Organic Compounds (VOC)	99.9	MMBTU/H	0.008	LB/MMBTU	Hourly	Good combustion practices
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Volatile Organic Compounds (VOC)	53.7	MMBTU/HR	0.054	LB/MMBTU		Combustion Of Natural Gas And Good Combustion Practice

Table D-2.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0327	PERDUE GRAIN AND OILSEED, LLC	(4) 27 MMBtu/hr boilers, Natural gas and No. 2 fuel oi	07/12/2017	Volatile Organic Compounds (VOC)	0		0.1	LB/HR		
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Volatile Organic Compounds (VOC)	26.8	MMBTU/H	0.13	LB/H		Good combustion controls
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Volatile Organic Compounds (VOC)	44.55	MMBTU/H	0.16	LB/H		Good combustion practices
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Volatile Organic Compounds (VOC)	34	MMBTU/H	0.2	LB/H		Good combustion controls
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Volatile Organic Compounds (VOC)	37.8	MMBTU/H	0.23	LB/H		Good combustion controls
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Volatile Organic Compounds (VOC)	37.8	MMBTU/H	0.23	LB/H		good combustion controls
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Volatile Organic Compounds (VOC)	80	MMBTU/H	0.248	LB/H		Good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Volatile Organic Compounds (VOC)	50	MMBTU/H	0.3	LB/H	HOURLY	Good combustion practices
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Volatile Organic Compounds (VOC)	50	MMBTU/H	0.3	LB/H	HOURLY	Good combustion practices.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Volatile Organic Compounds (VOC)	13.2	MMBTU/H	0.3	T/YR		Good combustion practice to ensure complete combustion.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Volatile Organic Compounds (VOC)	687	MMCFT/YR	0.32	LB/H	AV OF THREE ONE H STACK TESTS	Use of good combustion practices and use of natural gas a clean burning fuel
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Volatile Organic Compounds (VOC)	4000	H/YR	0.488	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL AND GOOD COMBUSTION PRACTICES
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Volatile Organic Compounds (VOC)	99	MMBTU/H	0.5	LB/H	HOURLY	Good combustion practices.
*NE-0064	NORFOLK CRUSH, LLC	Boiler A	11/21/2022	Volatile Organic Compounds (VOC)	84	MMBtu/hr	0.52	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0064	NORFOLK CRUSH, LLC	Boiler B	11/21/2022	Volatile Organic Compounds (VOC)	84	MMBtu/hr	0.52	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Volatile Organic Compounds (VOC)	99	MMBTU/H	0.59	LB/H		Good combustion controls and natural gas/ultra low sulfur diesel
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Volatile Organic Compounds (VOC)	77.8	mmBtu/hr	0.62	LB/HR		Use of Natural Gas, Good Combustion Practices
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Volatile Organic Compounds (VOC)	111.9	mmBtu/hr	0.9	LB/HR		Use of Natural Gas, Good Combustion Practices

Table D-2.2 Summary of VOC BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0751	EAGLE MOUNTAIN STEAM ELECTRIC STATION	Commercial/Institutional Size Boilers (<100 MMBtu) â€“ natural gas	06/18/2015	Volatile Organic Compounds (VOC)	73.3	MMBTU/H	4	PPM	1-HR AVG	
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Volatile Organic Compounds (VOC)	29.4	MMBTU/H	4.86	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Volatile Organic Compounds (VOC)	95.7	MMBTU/H	5.42	T/YR		Good combustion practice to ensure complete combustion.
*IN-0361	C-PLANT (SPECIALTY SOYBEAN EXTRACTION)	SPC Boiler #1 PS37 & SPC Boiler #2 PS38	05/12/2023	Volatile Organic Compounds (VOC)	73.6	MMBtu/hr (each)	5.5	LB/MMCF (EACH)		Good Combustion Practices
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Volatile Organic Compounds (VOC)	50.4	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 â€“ Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Volatile Organic Compounds (VOC)	18	MMBtu/hr, each	5.5	LB/MMSCF	Each	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
SC-0193	MERCEDES BENZ VANS, LLC	Energy Center Boilers	04/15/2016	Volatile Organic Compounds (VOC)	14.27	MMBTU/hr	5.5	LB/MMSCF	3 HOUR BLOCK AVERAGE	Annual tune ups per 40 CFR 63.7540(a)(10) are required.
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Volatile Organic Compounds (VOC)	94	mm btu/h	13.37	LB/H		Good combustion practices and oxidation catalyst

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Nitrogen Oxides (NOx)	50	MMBTU/H	7	PPMV	3-HR AVG @ 15 % O2	Selective Catalytic Reduction
AL-0307	ALLOYS PLANT	2 CALP LINE BOILERS	10/09/2015	Nitrogen Oxides (NOx)	24.59	MMBTU/H	30	PPMVD	3% O2	LOW NOX BURNER FLUE GAS RECIRCULATION (FGR) GOOD COMBUSTION PRACTICES (GCP)
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Nitrogen Oxides (NO_x)	17.5	MMBTU/H	30	PPMVD	3% O2	LOW NOX BURNER FLUE GAS RECIRCULATION GCP
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Nitrogen Oxides (NOx)	90.5	MMBtu/hr	0.011	LB/MMBTU	3 HOUR AVG	
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Nitrogen Oxides (NOx)	53.7	MMBTU/HR	0.035	LB/MMBTU		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Nitrogen Oxides (NOx)	53.7	MMBTU/HR	0.035	LB/MMBTU		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		Low NOx burners, Combustion of clean fuel, and Good Combustion Practices
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		LOW NOX BURNERS COMBUSTION OF CLEAN FUEL GOOD COMBUSTION PRACTICES
AR-0167	LION OIL COMPANY	SN-805 - #4 Pre-Flash Reboiler	12/01/2020	Nitrogen Oxides (NOx)	75	MMBtu/hr	3.5	LB/HR	3-HOUR AVERAGE	Ultra-low NOx burners and good combustion practice
AR-0167	LION OIL COMPANY	SN-810 - #9 Hydrotreater Furnace/Reboiler	12/01/2020	Nitrogen Oxides (NOx)	70	MMBtu/hr	12.7	LB/HR	3-HOUR AVERAGE	

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0167	LION OIL COMPANY	SN-803 - #4 Pre-Flash Column Reboiler	12/01/2020	Nitrogen Oxides (NOx)	40	MMBtu/hr	1.9	LB/HR	3-HOUR AVERAGE	Ultra-low NOx burners and good combustion practice
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Nitrogen Oxides (NOx)	50.4	MMBTU/hr	0.035	LB/MMBTU		Low Nox Burners
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Nitrogen Oxides (NO_x)	15	MMBTU/hr each	0.1	LB/MMBTU	3-HR	Low Nox Burners
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		Low NOx burners
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Nitrogen Oxides (NOx)	53.7	MMBtu/hr	0.035	LB/MMBTU		Low NOx burners Combustion of clean fuel Good Combustion Practices
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Nitrogen Oxides (NOx)	53.7	MMBtu/hr	0.035	LB/MMBTU		Low NOx burners Combustion of clean fuel Good Combustion Practices
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Nitrogen Oxides (NOx)	53.7	MMBtu/hr	0.035	LB/MMBTU		Low NOx burners Combustion of clean fuel Good Combustion Practices
CT-0159	CPV TOWANTIC, LLC	Aux Boiler	11/30/2015	Nitrogen Oxides (NOx)	359.6	MMCF	7	PPMVD @3% O2		Boiler permit does not specify any add-on control other than ultr-low NOx burner. Unit may be required to use additional control options to meet emissions limit.
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Auxiliary Boiler, 99.8 MMBtu/hr	03/09/2016	Nitrogen Oxides (NOx)	99.8	MMBtu/hr	0.05	LB/MMBTU		Low-NOx burners
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Nitrogen Oxides (NOx)	60	MMBtu/hour	0.05	LB/MMBTU		low-NOx burners
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Nitrogen Oxides (NOx)	60	MMBtu/hour	0.05	LB/MMBTU		Low-NOx burners
IA-0107	MARSHALLTOWN GENERATING STATION	auxiliary boiler	04/14/2014	Nitrogen Oxides (NOx)	60.1	mmBtu/hr	0.013	LB/MMBTU	AVERAGE OF 3 ONE-HOUR TEST RUNS	
IL-0129	CPV THREE RIVERS ENERGY CENTER	Auxiliary Boiler	07/30/2018	Nitrogen Oxides (NOx)	96	mmBtu/hr	0.011	LB/MMBTU	3-HOUR AVERAGE	Ultra-low NOx burners and flue gas recirculation, air preheater, automated combustion management system with O2 trim system and automated water blowdown, and good combustion practices.

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0130	JACKSON ENERGY CENTER	Auxiliary Boiler	12/31/2018	Nitrogen Oxides (NOx)	96	mmBtu/hr	0.01	LB/MMBTU	3-HOUR AVERAGE	Ultra low-NOx burners and flue gas recirculation air preheater, automated combustion management systems, automated water blowdown, good combustion practices
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Nitrogen Oxides (NOx)	80	mmBtu/hour	0.01	POUNDS/MMBTU	ROLLING 3-OPERATING HOUR	Ultra low-NOx burners and flue gas recirculation, air preheater, automated combustion management system, with an oxygen trim system and an automated water blowdown system.
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Nitrogen Oxides (NOx)	50	MMBtu/hr	0.035	LB/MMBTU		low NOx burners
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Nitrogen Oxides (NOx)	96	MMBtu per hour	0.037	LB PER MMBTU	BASED ON A 3-HR AVERAGE	
*IN-0371	WABASH VALLEY RESOURCES, LLC	Auxiliary Boiler (AB-3)	01/11/2024	Nitrogen Oxides (NOx)	20	MMBtu/hr	35	LB/MMSCF		Low NOx burners and Good Combustion Practices
IN-0371	WABASH VALLEY RESOURCES, LLC	In tegrated Gasification Combined Cycle Combustion Turbines	1/11/2024	Nitrogen Oxides (NOx)	229.00	MMBtu/hr	2.00	PPMV @15% O2 when combusting >		Stem injection/SCR and good combustion practices
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Nitrogen Oxides (NOx)	48.2	MMBTU/H	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Nitrogen Oxides (NO_x)	17.7	MMBTU/H	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Nitrogen Oxides (NOx)	50.4	MMBtu/hr	35	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Also equipped with low-NOx burners.
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 â€" Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Nitrogen Oxides (NO_x)	18	MMBtu/hr, each	50	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Equipped with low-NOx burners.
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Nitrogen Oxides (NOx)	94	mm btu/h	14.41	LB/H	12-MONTH ROLLING AVERAGE	SCR and LNB

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Nitrogen Oxides (NOx)	80	mm BTU/h	0.01	LB/MM BTU		Ultra-low NOx burners and good combustion practices.
MA-0039	SALEM HARBOR STATION REDEVELOPMENT	Auxiliary Boiler	01/30/2014	Nitrogen Oxides (NOx)	80	MMBTU/H	0.011	LB/MMBTU	1 HR BLOCK AVG, DOES NOT APPLY DURING SS	ultra low NOx burners
MD-0041	CPV ST. CHARLES	AUXILLARY BOILER	04/23/2014	Nitrogen Oxides (NOx)	93	MMBTU/H	0.011	LB/MMBTU	3-HOUR AVERAGE	EXCLUSIVE USE OF NATURAL GAS, ULTRA LOW-NOX BURNERS, AND FLUE GAS RECIRCULATION (FGR)
MD-0042	WILDCAT POINT GENERATION FACILITY	AUXILLARY BOILER	04/08/2014	Nitrogen Oxides (NOx)	45	MMBTU/H	0.01	LB/MMBTU	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Nitrogen Oxides (NOx)	42	MMBTU/H	0.01	LB/MMBTU	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, ULTRA LOW-NOX BURNERS, AND GOOD COMBUSTION PRACTICES
MD-0046	KEYS ENERGY CENTER	AUXILIARY BOILER	10/31/2014	Nitrogen Oxides (NOx)	93	MMBTU/H	0.01	LB/MMBTU	3-HOUR BLOCK AVERAGE	EFFICIENT BOILER DESIGN WITH ULTRA LOW NOX BURNER, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, AND APPLICATION OF GOOD COMBUSTION PRACTICES
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Nitrogen Oxides (NO_x)	6	MMBTU/H	14	PPMVOL	AT 15%O2; TEST PROTOCOL	Ultra low NOx burners and good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Nitrogen Oxides (NOx)	83.5	MMBTU/H	0.05	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Low NOx burners/Internal flue gas recirculation and good combustion practices.
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	03/24/2017	Nitrogen Oxides (NO_x)	3	MMBTU/H	20	PPM AT 3% O2	EACH 3 MMBTU/H BOILER	Ultra-low NOx burners and good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Nitrogen Oxides (NOx)	61.5	MMBTU/H	0.04	LB/MMBTU	30-DAY ROLLING AVG TIME PERIOD	Low NOx burners/flue gas recirculation and good combustion practices.

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Nitrogen Oxides (NOx)	61.5	MMBTU/h	0.04	LB/MMBTU	30 DAY ROLLING AVG TIME PERIOD	Low NOx burners/flue gas recirculation and good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Nitrogen Oxides (NOx)	99.9	MMBTU/H	0.036	LB/MMBTU	HOURLY	Low NOx burners/Flue gas recirculation.
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Nitrogen Oxides (NOx)	99	MMBTU/H	30	PPM	@3%O2; HOURLY	Low NOx burners (LNB) or flue gas recirculation along with good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Nitrogen Oxides (NOx)	80	MMBTU/H	0.036	LB/MMBTU	HOURLY; EACH BOILER	Good combustion practices and low NOx burners.
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Nitrogen Oxides (NOx)	50	MMBTU/H	30	PPM	AT 3% O2; HOURLY	Low NOx burners (LNB) or flue gas recirculation (FGR) along with good combustion practices.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Nitrogen Oxides (NOx)	61.5	MMBTU/H	0.04	LB/MMBTU	30-DAY ROLLING AVERAGE	Low NOx burners/Flue gas recirculation and good combustion practices.
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Nitrogen Oxides (NOx)	61.5	MMBTU/H	0.04	LB/MMBTU	30-DAY ROLLING AVERAGE	Low NOx Burners/Flue Gas Recirculation and Good Combustion Practices
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Nitrogen Oxides (NOx)	50	MMBTU/H	30	PPM	HOURLY	Low NOx Burners (LNB) or Flue Gas Recirculation (FGR) along with good combustion practices.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Nitrogen Oxides (NOx)	687	MMCFT/YR	0.8	LB/H	AV OF THREE ONE H STACK TESTS	low NOx burners and flue gas recirculation (FGR)
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Nitrogen Oxides (NOx)	4000	H/YR	0.975	LB/H	AV OF THREE ONE H INITIAL STACK TEST	Low NOx burners and Flue Gas Recirculation (FGR) and use of natural gas a clean burning fuel
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Nitrogen Oxides (NOx)	60	MMBTU/H	0.0085	LB/MMBTU	1 H	flue gas recirculation with low NOx burners, RACT/LAER
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Nitrogen Oxides (NOx)	34	MMBTU/H	0.68	LB/H		Flue gas recirculation (FGR) and low NOx burner

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Nitrogen Oxides (NOx)	99	MMBTU/H	9.9	LB/H		Flue gas recirculation (FGR), low NOx burner, and natural gas/ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Nitrogen Oxides (NOx)	37.8	MMBTU/H	0.76	LB/H		Flue gas recirculation (FGR), low NOx burner
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Nitrogen Oxides (NOx)	37.8	MMBTU/H	0.76	LB/H		low NOX burners and flue gas recirculation
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Nitrogen Oxides (NOx)	26.8	MMBTU/H	0.29	LB/H		Flue gas recirculation and low NOX burner
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Nitrogen Oxides (NOx)	44.55	MMBTU/H	1.56	LB/H		Good combustion practices and low NOx burner
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Nitrogen Oxides (NOx)	80	MMBTU/H	2.19	LB/H		Good combustion practices and low NOx burner
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Nitrogen Oxides (NOx)	15.17	MMBTU/H	0.634	LB/H		Low-NOX burners, good combustion practices and the use of natural gas
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Nitrogen Oxides (NOx)	29.4	MMBTU/H	9.74	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Ultra-low NOX burners, good combustion practices, and the use of natural gas
OR-0050	TROUTDALE ENERGY CENTER, LLC	Auxiliary boiler	03/05/2014	Nitrogen Oxides (NOx)	39.8	MMBTU/H	0.035	LB/MMBTU	3-HR BLOCK AVERAGE	Utilize Low-NOx burners and FGR.
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Nitrogen Oxides (NOx)	62.04	MCF/hr	0.0086	LB/MMBTU		Good combustion practices, Ultra-Low NOx burners, FGR
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Nitrogen Oxides (NO_x)	13.31	MMBtu/hr	0.006	LB/MMBTU	30-DAY ROLLING AVERAGE BASIS	SCR and ultra low NOx burners, Fired only on natural gas supplied by a public utility.
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Nitrogen Oxides (NOx)	92.4	MMBtu/hr	0.011	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	Ultra low NOx burners, FGR, good combustion practices
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Nitrogen Oxides (NOx)	55.4	MMBtu/hr	0.006	LB/MMBTU		Noted as either 0.006lb/MMBtu or 0.66 tpy Nox limit with fuel restriction as well (214.9 MMscf/yr)

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*PA-0316	RENOVO ENERGY CENTER, LLC	Auxiliary Boiler	01/26/2018	Nitrogen Oxides (NOx)	118800	MMBtu/12 month period	0.011	LB	MMBTU	Ultra-low NOx burners and flue gas re-circulation; operated in accordance with the manufacturer specifications and good operating practices
*PA-0319	RENAISSANCE ENERGY CENTER	NATURAL GAS FIRED AUXILIARY BOILER	08/27/2018	Nitrogen Oxides (NOx)	88	MMBtu/hr	0.02	LB/MMBTU	HR	Lo-NOx burners, Flue Gas Recirculation, good combustion practices, proper operation and maintainance.
TX-0713	TENASKA BROWNSVILLE GENERATING STATION	boiler	04/29/2014	Nitrogen Oxides (NOx)	90	MMBTU/H	9	PPMVD	@15% O2	ultra low-NOx burners, limited use
TX-0714	S R BERTRON ELECTRIC GENERATING STATION	boiler	12/19/2014	Nitrogen Oxides (NOx)	80	MMBTU/H	0.036	LB/MMBTU	3-HR ROLLING	low-NOx burners
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Nitrogen Oxides (NO_x)	13.2	MMBTU/H	0.1	LB/MMBTU		
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Nitrogen Oxides (NOx)	95.7	MMBTU/H	0.011	LB/MMBTU		Low NOx burners and flue gas recirculation
TX-0975	Freestone Peakers Plant	Simple Cycle Gas Turbines	6/13/2024	Nitrogen Oxides (NOx)	221.00	MW	9.00	ppmvd 15% O2		Dry low-NOx burners (DLNB) and good combustion practices.
WI-0283	AFE, INC. â€“LCM PLANT	B01-B12, Boilers	04/24/2018	Nitrogen Oxides (NOx)	28	mmBTU/hr	0.0105	LB/MMBTU		Ultra-low NOx Burners, Flue Gas Recirculation and Good Combustion Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Nitrogen Oxides (NOx)	28	mmBTU	0.0105	LB/MMBTU	1-HOUR AVERAGE	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Nitrogen Oxides (NOx)	100	MMBTU/H	0.011	LB/MMBTU		Ultra-low NOx burners, flue gas recirculation, and operate and maintain B02 according to the manufacturer recommendations.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Nitrogen Oxides (NO_x)	14.67	MMBTU/H	0.04	LB/MMBTU	AVG. OVER ANY CONSECUTIVE 3-HR PERIOD	Low NOx burners, flue gas recirculation, shall be operated for no more than 500 hours, and shall combust only pipeline quality natural gas.
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Nitrogen Oxides (NOx)	77.8	mmBtu/hr	0.86	LB/HR		LNB, FGR, Good Combustion Practices

Table D-2.3 Summary of NO_x BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Nitrogen Oxides (NOx)	111.9	mmBtu/hr	1.23	LB/HR		LNB, Good Combustion Practices
WY-0075	CHEYENNE PRAIRIE GENERATING STATION	Auxiliary Boiler	07/16/2014	Nitrogen Oxides (NOx)	25.06	MMBtu/h	0.0175	LB/MMBTU	3 HOUR AVERAGE	Ultra low NOx burners and flue gas recirculation

Table D-2.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AL-0282	LENZING FIBERS, INC.	Natural Gas Fired Boilers (3)	01/22/2014	Particulate matter, filterable (FPM)	100	mm btu/hr	0.0075			Good combustion Practices.
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Particulate matter, filterable (FPM)	53.7	MMBTU/HR	0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Particulate matter, filterable (FPM)	53.7	MMBTU/HR	6.8	X10^-4 LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Particulate matter, filterable (FPM)	0		0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Particulate matter, filterable (FPM)	0		0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Particulate matter, filterable (FPM)	0		0.0007	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Particulate matter, filterable (FPM)	50.4	MMBTU/hr	0.0019	LB/MMBTU	3-HR	Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Particulate matter, filterable (FPM)	15	MMBTU/hr each	0.0019	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Particulate matter, filterable (FPM)	0		0.0019	LB/MMBTU		Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Particulate matter, filterable (FPM)	53.7	MMBtu/hr	0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Particulate matter, filterable (FPM)	53.7	MMBtu/hr	0.0007	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Particulate matter, filterable (FPM)	53.7	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
FL-0363	DANIA BEACH ENERGY CENTER	99.8 MMBtu/hr auxiliary boiler	12/04/2017	Particulate matter, filterable (FPM)	99.8	MMBtu/hr	0			Clean fuels
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Particulate matter, filterable (FPM)	60	MMBtu/hour	0			Clean fuels
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Particulate matter, filterable (FPM)	60	MMBtu/hour	1.4	GR. S/100 SCF NG	FUEL RECORDKEEPING	
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Particulate matter, filterable (FPM)	50	MMBtu/hr	0.0007	LB/MMBTU		good combustion practices and only pipeline quality natural gas fuel shall be combusted
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Particulate matter, filterable (FPM)	50.4	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 â€“ Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Particulate matter, filterable (FPM)	18	MMBtu/hr, each	1.9	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
MD-0041	CPV ST. CHARLES	AUXILLARY BOILER	04/23/2014	Particulate matter, filterable (FPM)	93	MMBTU/H	0.005	LB/MMBTU	3-HOUR AVERAGE	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
MD-0042	WILDCAT POINT GENERATION FACILITY	AUXILLARY BOILER	04/08/2014	Particulate matter, filterable (FPM)	45	MMBTU/H	0.0075	LB/MMBTU	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Particulate matter, filterable (FPM)	42	MMBTU/H	0.0019	LB/MMBTU	3-HOUR BLOCK AVERAGE	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES

Table D-2.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MD-0046	KEYS ENERGY CENTER	AUXILIARY BOILER	10/31/2014	Particulate matter, filterable (FPM)	93	MMBTU/H	0.0075	LB/MMBTU	3-HOUR BLOCK AVERAGE	EFFICIENT BOILER DESIGN, EXCLUSIVE USE OF PIPELINE QUALITY NATURAL GAS, AND APPLICATION OF GOOD COMBUSTION PRACTICES
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Particulate matter, filterable (FPM)	83.5	MMBTU/H	0.0018	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Particulate matter, filterable (FPM)	61.5	MMBTU/H	0.005	LB/MMBTU	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Particulate matter, filterable (FPM)	61.5	MMBTU/h	0.005	LB/MMBTU	HOURLY	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Particulate matter, filterable (FPM)	99.9	MMBTU/H	0.007	LB/MMBTU	HOURLY	Good combustion practices, low sulfur fuel
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Particulate matter, filterable (FPM)	61.5	MMBTU/H	0.005	LB/MMBTU	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Particulate matter, filterable (FPM)	61.5	MMBTU/H	0.005	LB/MMBTU	HOURLY	Good combustion practices.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Particulate matter, filterable (FPM)	687	MMCFT/YR	0.26	LB/H	AV OF THREE ONE HOUR STACK TESTS	Use of natural gas a clean burning
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Particulate matter, filterable (FPM)	4000	H/YR	0.181	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Particulate matter, filterable (FPM)	60	MMBTU/H	0.005	LB/MMBTU	1 H	good combustion practiced and pipeline quality natural gas
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Particulate matter, filterable (FPM)	29.4	MMBTU/H	1.68	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Particulate matter, filterable (FPM)	13.31	MMBtu/hr	0.002	LB/MMBTU		Natural gas fired exclusively
TX-0975	Freestone Peakers Plant	Simple Cycle Gas Turbines	6/13/2024	Particulate matter, filterable (FPM)	221	MW				Good combustion practices

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Particulate matter, total (TPM2.5)	8.72	mmBtu/hr	0			Limited to natural gas
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Particulate matter, total (TPM10)	8.72	mmBtu/hr	0			Limited to natural gas
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Particulate matter, total (TPM10)	50	MMBTU/H	0.0074	LB/MMBTU	3-HR AVG	Limited Use (200 hr/yr)
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Particulate matter, total (TPM2.5)	50	MMBTU/H	0.0074	LB/MMBTU	3-HR AVG	
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Particulate matter, total (TPM2.5)	53.7	MMBTU/HR	0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Particulate matter, total (TPM2.5)	53.7	MMBTU/HR	6.8	X10^-4 LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	11/07/2018	Particulate matter, total (TPM10)	53.7	MMBTU/HR	0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0155	BIG RIVER STEEL LLC	BOILER SN-26, GALVANIZING LINE	11/07/2018	Particulate matter, total (TPM10)	53.7	MMBTU/HR	6.8	X10^-4 LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0007	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, PICKLE LINE	04/05/2019	Particulate matter, total (TPM10)	0		0.0019	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	BOILER, ANNEALING PICKLE LINE	04/05/2019	Particulate matter, total (TPM10)	0		0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0159	BIG RIVER STEEL LLC	BOILERS SN-26 AND SN-27, GALVANIZING LINE	04/05/2019	Particulate matter, total (TPM10)	0		0.0007	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Particulate matter, total (TPM2.5)	50.4	MMBTU/hr	0.0076	LB/MMBTU	3-HR	Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Particulate matter, total (TPM2.5)	15	MMBTU/hr each	0.0076	LB/MMBTU		Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Particulate matter, total (TPM10)	50.4	MMBTU/hr	0.0076	LB/MMBTU	3-HR	Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Particulate matter, total (TPM10)	15	MMBTU/hr each	0.0076	LB/MMBTU		Good combustion practices

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Particulate matter, total (TPM2.5)	0		0.0076	GR/DSCF		Good Combustion Practice
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Particulate matter, total (TPM10)	0		0.0076	GR/DSCF		Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Particulate matter, total (TPM2.5)	53.7	MMBtu/hr	0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Particulate matter, total (TPM2.5)	53.7	MMBtu/hr	0.0007	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Particulate matter, total (TPM2.5)	53.7	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Particulate matter, total (TPM10)	53.7	MMBtu/hr	0.0019	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Particulate matter, total (TPM10)	53.7	MMBtu/hr	0.0007	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Particulate matter, total (TPM10)	53.7	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
FL-0363	DANIA BEACH ENERGY CENTER	99.8 MMBtu/hr auxiliary boiler	12/04/2017	Particulate matter, total (TPM10)	99.8	MMBtu/hr	0			Clean fuels
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Particulate matter, total (TPM10)	60	MMBtu/hour	0			Clean fuels
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Particulate matter, total (TPM10)	80	mmBtu/hour	0.0075	POUNDS/MMBTU	ROLLING 3-OPERATING HOUR	Good combustion practices.
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Particulate matter, total (TPM2.5)	50	MMBtu/hr	0.0007	LB/MMBTU		good combustion practices and only pipeline quality natural gas fuel shall be combusted
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Particulate matter, total (TPM10)	50	MMBtu/hr	0.0007	LB/MMBTU		good combustion practices and only pipeline quality natural gas fuel shall be combusted
*IN-0361	C-PLANT (SPECIALTY SOYBEAN EXTRACTION)	SPC Boiler #1 PS37 & SPC Boiler #2 PS38	05/12/2023	Particulate matter, total (TPM2.5)	73.6	MMBtu/hr (each)	7.6	LB/MMCF (EACH)		Good Combustion Practices

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0361	C-PLANT (SPECIALTY SOYBEAN EXTRACTION)	SPC Boiler #1 PS37 & SPC Boiler #2 PS38	05/12/2023	Particulate matter, total (TPM10)	73.6	MMBtu/hr (each)	7.6	LB/MMCF (EACH)		Good Combustion Practices
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Particulate matter, total (TPM2.5)	96	MMBtu per hour	0.0075	LB PER MMBTU	BASED ON A 3-HR AVERAGE	
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Particulate matter, total (TPM10)	96	MMBtu per hour	0.0075	LB PER MMBTU	BASED ON A 3-HR AVERAGE	
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Auxiliary boiler	07/14/2015	Particulate matter, total (TPM10)	18.6	MMBTU/HR	0.005	LB PER MMBTU		
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Auxiliary boiler	07/14/2015	Particulate matter, total (TPM2.5)	18.6	MMBTU/HR	0.005	LB PER MMBTU		
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Particulate matter, total (TPM2.5)	48.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Particulate matter, total (TPM2.5)	17.7	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2502	10/30/2019	Particulate matter, total (TPM10)	48.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2701	10/30/2019	Particulate matter, total (TPM10)	17.7	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Particulate matter, total (TPM2.5)	50.4	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Particulate matter, total (TPM2.5)	18	MMBtu/hr, each	7.6	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Particulate matter, total (TPM10)	50.4	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Particulate matter, total (TPM10)	18	MMBtu/hr, each	7.6	LB/MMSCF	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Particulate matter, total (TPM2.5)	94	mm btu/h	0.61	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Particulate matter, total (TPM10)	94	mm btu/h	0.61	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Particulate matter, total (TPM2.5)	80	mm BTU/h	0.0074	LB/MM BTU		Combusts exclusively natural gas and good combustion practices.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Particulate matter, total (TPM10)	80	mm BTU/h	0.0074	LB/MM BTU		Exclusive combustion of natural gas and good combustion practices.
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Particulate matter, total (TPM2.5)	42	MMBTU/H	0.0075	LB/MMBTU	3-HOUR BLOCK AVERAGE	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Particulate matter, total (TPM10)	42	MMBTU/H	0.0075	LB/MMBTU	3-HOUR BLOCK AVERAGE	USE OF PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Particulate matter, total (TPM2.5)	6	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Particulate matter, total (TPM10)	6	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Particulate matter, total (TPM2.5)	83.5	MMBTU/H	0.007	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Particulate matter, total (TPM10)	83.5	MMBTU/H	0.007	LB/MMBTU	TEST PROTOCOL WIL SPECIFY AVG TIME	Good combustion practices.
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C,	03/24/2017	Particulate matter, total (TPM2.5)	3	MMBTU/H	0.52	LB/MMSCF	EACH BOILER	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C,	03/24/2017	Particulate matter, total (TPM10)	3	MMBTU/H	0.52	LB/MMSCF	EACH BOILER	Good combustion practices and low sulfur fuel (pipeline quality natural gas).
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Particulate matter, total (TPM2.5)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices.

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Particulate matter, total (TPM2.5)	61.5	MMBTU/h	0.46	LB/H	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Particulate matter, total (TPM10)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Particulate matter, total (TPM10)	61.5	MMBTU/h	0.46	LB/H	HOURLY	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Particulate matter, total (TPM2.5)	99.9	MMBTU/H	0.007	LB/MMBTU	HOURLY	Good combustion practices, low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Particulate matter, total (TPM10)	99.9	MMBTU/H	0.007	LB/MMBTU	HOURLY	Good combustion practices, low sulfur fuel
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Particulate matter, total (TPM2.5)	99	MMBTU/H	0.74	LB/H	HOURLY	Good combustion practices
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Particulate matter, total (TPM10)	99	MMBTU/H	0.74	LB/H	HOURLY	Good combusion practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Particulate matter, total (TPM2.5)	80	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH BOILER	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Particulate matter, total (TPM10)	80	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH BOILER	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Particulate matter, total (TPM2.5)	50	MMBTU/H	0.4	LB/H	HOURLY	Good combustion practices.
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Particulate matter, total (TPM10)	50	MMBTU/H	0.74	LB/H	HOURLY	Good combustion practices.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM2.5)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM10)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM2.5)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Particulate matter, total (TPM10)	61.5	MMBTU/H	0.46	LB/H	HOURLY	Good combustion practices

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Particulate matter, total (TPM2.5)	50	MMBTU/H	0.4	LB/H	HOURLY	Good combustion practices.
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Particulate matter, total (TPM10)	50	MMBTU/H	0.4	LB/H	HOURLY	Good combustion practices.
*NE-0064	NORFOLK CRUSH, LLC	Boiler A	11/21/2022	Particulate matter, total (TPM10)	84	MMBtu/hr	0.26	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0064	NORFOLK CRUSH, LLC	Boiler B	11/21/2022	Particulate matter, total (TPM10)	84	MMBtu/hr	0.26	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0068	AG PROCESSING INC - DAVID CITY	Boiler 1	06/27/2023	Particulate matter, total (TPM10)	95.6	MMBtu/hr	1.43	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0068	AG PROCESSING INC - DAVID CITY	Boiler 2	06/27/2023	Particulate matter, total (TPM10)	95.6	MMBtu/hr	1.43	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
*NE-0068	AG PROCESSING INC - DAVID CITY	Boiler 3	06/27/2023	Particulate matter, total (TPM10)	95.6	MMBtu/hr	1.43	LB/HR	THREE 1-HOUR TESTS / TEST METHOD AVERAGE	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Particulate matter, total (TPM2.5)	687	MMCFT/YR	0.4	LB/H	AV OF THREE ONE HOUR STACK TESTS	use of natural gas a clean burning fuel
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Particulate matter, total (TPM10)	687	MMCFT/YR	0.4	LB/H	AV OF THREE ONE HOUR STACK TESTS	use of natural gas a clean burning fuel
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Particulate matter, total (TPM2.5)	4000	H/YR	0.488	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Particulate matter, total (TPM10)	4000	H/YR	0.488	LB/H	AV OF THREE ONE H STACK TESTS INITIALLY	USE OF NATURAL GAS A CLEAN BURNING FUEL
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Particulate matter, total (TPM10)	34	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Particulate matter, total (TPM2.5)	34	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Particulate matter, total (TPM2.5)	99	MMBTU/H	5.94	LB/H		natural gas/ultra low sulfur diesel
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Particulate matter, total (TPM10)	99	MMBTU/H	5.94	LB/H		natural gas/ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Particulate matter, total (TPM2.5)	37.8	MMBTU/H	0.3	LB/H		Low sulfur fuel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Particulate matter, total (TPM10)	37.8	MMBTU/H	0.3	LB/H		Low sulfur fuel
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Particulate matter, total (TPM2.5)	37.8	MMBTU/H	0.3	LB/H		low sulfur fuel

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Particulate matter, total (TPM10)	37.8	MMBTU/H	0.3	LB/H		low sulfur fuel
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Particulate matter, total (TPM2.5)	26.8	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Particulate matter, total (TPM10)	26.8	MMBTU/H	0.27	LB/H		Low sulfur fuel
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Particulate matter, total (TPM2.5)	44.55	MMBTU/H	0.33	LB/H		Pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Particulate matter, total (TPM10)	44.55	MMBTU/H	0.33	LB/H		Pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Particulate matter, total (TPM2.5)	80	MMBTU/H	0.48	LB/H		Pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Particulate matter, total (TPM10)	80	MMBTU/H	0.48	LB/H		Pipeline quality natural gas
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Particulate matter, total (TPM2.5)	15.17	MMBTU/H	0.113	LB/H	SEE NOTES.	Good combustion practices and the use of natural gas
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Particulate matter, total (TPM10)	15.17	MMBTU/H	0.113	LB/H	SEE NOTES.	Good combustion practices and the use of natural gas
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Particulate matter, total (TPM2.5)	29.4	MMBTU/H	0.38	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
OH-0387	INTEL OHIO SITE	29.4 MMBtu/hr Natural Gas-Fired Boilers: B001 through B028	09/20/2022	Particulate matter, total (TPM10)	29.4	MMBTU/H	0.46	T/YR	PER ROLLING 12 MONTH PERIOD B001 TO B014	Good combustion practices and the use of natural gas
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Particulate matter, total (TPM10)	62.04	MCF/hr	0.005	LB/MMBTU		Good combustion practices and low sulfur fuels
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Particulate matter, total (TPM2.5)	13.31	MMBtu/hr	0.007	LB/MMBTU		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Particulate matter, total (TPM10)	13.31	MMBtu/hr	0.007	LB/MMBTU		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Particulate matter, total (TPM2.5)	92.4	MMBtu/hr	0.007	LB/MMBTU		ULSD and good combustion practices
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Particulate matter, total (TPM10)	92.4	MMBtu/hr	0.007	LB/MMBTU		ULSD and good combustion practices
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Particulate matter, total (TPM10)	55.4	MMBtu/hr	0.007	LB/MMBTU		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Particulate matter, total (TPM2.5)	55.4	MMBtu/hr	0.007	LB/MMBTU		

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
SC-0193	MERCEDES BENZ VANS, LLC	Energy Center Boilers	04/15/2016	Particulate matter, total (TPM2.5)	14.27	MMBTU/hr	7.6	LB/MMSCF	3 HOUR BLOCK AVERAGE	Annual tune ups per 40 CFR 63.7540(a)(10) are required.
SC-0193	MERCEDES BENZ VANS, LLC	Energy Center Boilers	04/15/2016	Particulate matter, total (TPM10)	14.27	MMBTU/hr	7.6	LB/MMSCF	3 HOUR BLOCK AVERAGE	Annual tune ups per 40 CFR 63.7540(a)(10) are required.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM2.5)	95.7	MMBTU/H	7.49	T/YR		Use of gaseous fuel with efficient combustion.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM10)	95.7	MMBTU/H	7.49	T/YR		Use of gaseous fuel with efficient combustion.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM10)	13.2	MMBTU/H	0.4	T/YR		Good combustion practice to ensure complete combustion.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Particulate matter, total (TPM2.5)	13.2	MMBTU/H	4	T/YR		Good combustion practice to ensure complete combustion.
VA-0333	NORFOLK NAVAL SHIPYARD	Three (3) boilers	12/09/2020	Particulate matter, total (TPM2.5)	76.6	MMBtu/hr	0.0078	LB	MMBTU	
VA-0333	NORFOLK NAVAL SHIPYARD	Three (3) boilers	12/09/2020	Particulate matter, total (TPM10)	76.6	MMBtu/hr	0.0078	LB	MMBTU	
WI-0283	AFE, INC. â€“LCM PLANT	B01-B12, Boilers	04/24/2018	Particulate matter, total (TPM2.5)	28	mmBTU/hr	0.0075	LB/MMBTU		Good Combustion Practices
WI-0283	AFE, INC. â€“LCM PLANT	B01-B12, Boilers	04/24/2018	Particulate matter, total (TPM10)	28	mmBTU/hr	0.0075	LB/MMBTU		Good Combustion Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Particulate matter, total (TPM2.5)	28	mmBTU	0.0075	LB/MMBTU		Good Combustion Practices and The Use of Pipeline Quality Natural Gas
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Particulate matter, total (TPM10)	28	mmBTU	0.0075	LB/MMBTU		Good Combustion Practices and The Use of Pipeline Quality Natural Gas
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Particulate matter, total (TPM2.5)	100	MMBTU/H	0.01	LB/MMBTU		Only combust pipeline quality natural gas and operate and maintain B02 according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Particulate matter, total (TPM10)	100	MMBTU/H	0.01	LB/MMBTU		Only combust pipeline quality natural gas and operate and maintain boiler according to the manufacturer's recommendations.

Table D-2.5 Summary of Total PM10/PM2.5 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Particulate matter, total (TPM2.5)	14.67	MMBTU/H	0.008	LB/MMBTU	HEAT INPUT	Combust only pipeline quality natural gas, can be operated for no more than 500 hours.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Particulate matter, total (TPM10)	14.67	MMBTU/H	0.008	LB/MMBTU	HEAT INPUT	Combust only pipeline quality natural gas, can be operated for no more than 500 hours.
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Particulate matter, total (TPM2.5)	8.72	mmBtu/hr	0			Limited to natural gas
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Particulate matter, total (TPM10)	8.72	mmBtu/hr	0			Limited to natural gas

Table D-2.6 Summary of H_2SO_4 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Sulfuric Acid (mist, vapors, etc)	96	MMBtu per hour	0.0001	LB PER MMBTU	BASED ON A 3-HOUR AVERAGE	
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Sulfuric Acid (mist, vapors, etc)	80	mmBtu/hour	0.02	POUNDS/MM BTU	ROLLING 3-OPERATING HOUR	Use of only natural gas with a sulfur content of no greater than 0.5 grains (gr)/100 standard cubic feet (scf).
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	06/07/2021	Sulfuric Acid (mist, vapors, etc)	60	MMBtu/hour	1.4	GR. S/100 SCF NG	FUEL RECORDKEEPING	Limited sulfur content in fuel
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	100	MMBTU/H	0.01	LB/H		Only combust pipeline quality natural gas and operate and maintain to the manufacturer's recommendations.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Sulfuric Acid (mist, vapors, etc)	14.67	MMBTU/H	0			Combust only pipeline quality natural gas.
IL-0130	JACKSON ENERGY CENTER	Auxiliary Boiler	12/31/2018	Sulfuric Acid (mist, vapors, etc)	96	mmBtu/hr	0.1	POUNDS/HOUR		Good combustion practice
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Sulfuric Acid (mist, vapors, etc)	111.9	mmBtu/hr	0.02	LB/HR		Use of Natural Gas
IL-0129	CPV THREE RIVERS ENERGY CENTER	Auxiliary Boiler	07/30/2018	Sulfuric Acid (mist, vapors, etc)	96	mmBtu/hr	0.1	LB/HR		Good combustion practice
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	60 MMBtu/hour Auxiliary Boiler	07/27/2018	Sulfuric Acid (mist, vapors, etc)	60	MMBtu/hour	0			Clean fuels
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Sulfuric Acid (mist, vapors, etc)	99.9	MMBTU/H	0.34	GR S/100 SCF	FUEL SUPPLIER RECORDS	Good combustion practices, low sulfur fuel
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	44.55	MMBTU/H	0.004	LB/H		Pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	80	MMBTU/H	0.018	LB/H		Pipeline quality natural gas
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Sulfuric Acid (mist, vapors, etc)	77.8	mmBtu/hr	0.0132	LB/HR		Use of Natural Gas

Table D-2.6 Summary of H_2SO_4 BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0363	DANIA BEACH ENERGY CENTER	99.8 MMBtu/hr auxiliary boiler	12/04/2017	Sulfuric Acid (mist, vapors, etc)	99.8	MMBtu/hr	0			Clean fuels
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Sulfuric Acid (mist, vapors, etc)	26.8	MMBTU/H	0.003	LB/H		Low sulfur fuel
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Sulfuric Acid (mist, vapors, etc)	37.8	MMBTU/H	0.004	LB/H		low sulfur fuel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Sulfuric Acid (mist, vapors, etc)	37.8	MMBTU/H	0.0087	LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Sulfuric Acid (mist, vapors, etc)	99	MMBTU/H	0.011	LB/H		natural gas/ultra low sulfur diesel
PA-0310	CPV FAIRVIEW ENERGY CENTER	Auxilary boiler	09/02/2016	Sulfuric Acid (mist, vapors, etc)	92.4	MMBtu/hr	0.0011	LB/MMBTU	AVG OF 3 1-HR TEST RUNS	ULSD and good combustion practices
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	AUXILIARY BOILER	07/19/2016	Sulfuric Acid (mist, vapors, etc)	4000	H/YR	0.01	LB/H		USE OF NATURAL GAS A CLEAN BURNING AND LOW SULFUR FUEL
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Auxiliary Boiler firing natural gas	03/10/2016	Sulfuric Acid (mist, vapors, etc)	687	MMCFT/YR	0.02	LB/H		Use of natural gas a low sulfur fuel
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Sulfuric Acid (mist, vapors, etc)	60	MMBTU/H	1.1	10-4 LB/MMBTU	1 H	natural gas with maximum sulfur content 0.4 grains/100 dscf
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Sulfuric Acid (mist, vapors, etc)	13.31	MMBtu/hr	0.0001	LB/MMBTU		
MD-0045	MATTAWOMAN ENERGY CENTER	AUXILIARY BOILER	11/13/2015	Sulfuric Acid (mist, vapors, etc)	42	MMBTU/H	0.004	LB/MMBTU	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF NATURAL GAS, AND GOOD COMBUSTION PRACTICES
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Sulfuric Acid (mist, vapors, etc)	55.4	MMBtu/hr	0.0001	LB/MMBTU		
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Sulfuric Acid (mist, vapors, etc)	34	MMBTU/H	0.004	LB/H		Low sulfur fuel
PA-0307	YORK ENERGY CENTER BLOCK 2 ELECTRICITY GENERATION PROJECT	Auxilary Boiler	06/15/2015	Sulfuric Acid (mist, vapors, etc)	62.04	MCF/hr	0	LB/MMBTU		Good combustion practices and low sulfur fuels

Table D-2.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Five (5) Waste Heat Boilers	01/06/2015	Carbon Dioxide Equivalent (CO_2e)	50	MMBTU/H	59.61	TONS/MMCF	3-HR AVG	
AL-0307	ALLOYS PLANT	PACKAGE BOILER	10/09/2015	Carbon Dioxide Equivalent (CO_2e)	17.5	MMBTU/H	34189	T/YR	12 MONTH ROLLING TOTAL	
AL-0307	ALLOYS PLANT	2 CALP LINE BOILERS	10/09/2015	Carbon Dioxide Equivalent (CO_2e)	24.59	MMBTU/H	34189	T/YR	12 MONTH ROLLING TOTAL	
AL-0328	PLANT BARRY	90.5 MMBtu/hr Aux Boiler	11/09/2020	Carbon Dioxide Equivalent (CO_2e)	90.5	MMBtu/hr	46416	TPY		
AR-0171	NUCOR STEEL ARKANSAS	SN-142 Vacuum Degasser Boiler	02/14/2019	Carbon Dioxide Equivalent (CO_2e)	50.4	MMBTU/hr	121	LB/MMBTU		Good combustion practices
AR-0171	NUCOR STEEL ARKANSAS	SN-233 Galvanizing Line Boilers	02/14/2019	Carbon Dioxide Equivalent (CO_2e)	15	MMBTU/hr each	121	LB/MMBTU		Good combustion practices
AR-0172	NUCOR STEEL ARKANSAS	SN-202, 203, 204 Pickle Line Boilers	09/01/2021	Carbon Dioxide Equivalent (CO_2e)	0		121	LB/MMBTU		Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Pickle Line Boiler	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	53.7	MMBtu/hr	117	LB/MMBTU		Good operating practices Minimum Boiler Efficiency
AR-0173	BIG RIVER STEEL LLC	Galvanizing Line Boilers #1 and #2	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	53.7	MMBtu/hr	117	LB/MMBTU		Good operating practices Minimum Boiler Efficiency
AR-0173	BIG RIVER STEEL LLC	Pickle Galvanizing Line Boiler	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	53.7	MMBtu/hr	This is one we completed	LB/MMBTU		Good operating practices
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Auxiliary Boiler, 99.8 MMBtu/hr	03/09/2016	Carbon Dioxide Equivalent (CO_2e)	99.8	MMBtu/hr	0			Use of natural gas only
IL-0129	CPV THREE RIVERS ENERGY CENTER	Auxiliary Boiler	07/30/2018	Carbon Dioxide Equivalent (CO_2e)	96	mmBtu/hr	22500	TON/YR	12-MONTH ROLLING AVERAGE	Good combustion practice
IL-0130	JACKSON ENERGY CENTER	Auxiliary Boiler	12/31/2018	Carbon Dioxide Equivalent (CO_2e)	96	mmBtu/hr	11250	TONS/YEAR	12-MONTH ROLLING AVERAGE	Good combustion practice
IL-0133	LINCOLN LAND ENERGY CENTER	Auxiliary Boiler	07/29/2022	Carbon Dioxide Equivalent (CO_2e)	80	mmBtu/hour	5059	TONS/YEAR	12 MONTH ROLLING	Good combustion practices.
IN-0359	NUCOR STEEL	Boiler (CC-BOIL)	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	50	MMBtu/hr	117.1	LB/MMBTU		energy efficiency measures and only pipeline quality natural gas fuel shall be combusted
*IN-0365	MAPLE CREEK ENERGY LLC	Auxiliary Boiler	06/19/2023	Carbon Dioxide Equivalent (CO_2e)	96	MMBtu per hour	11244	TONS PER YEAR		
*IN-0371	WABASH VALLEY RESOURCES, LLC	Auxiliary Boiler (AB-3)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	20	MMBtu/hr	117	LB/MMBTU		Good Combustion Practices
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Auxiliary boiler	07/14/2015	Carbon Dioxide Equivalent (CO_2e)	18.6	MMBTU/HR	9521.5	TONS PER YEAR	12-MONTH ROLLING AVERAGE BASIS	

Table D-2.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Vacuum Degasser Boiler (EP 20-13)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	50.4	MMBtu/hr	26125	TONS/YR	12-MONTH ROLLING	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
KY-0115	NUCOR STEEL GALLATIN, LLC	Pickle Line #2 Boiler #1 & #2 (EP 21-04 & EP 21-05)	04/19/2021	Carbon Dioxide Equivalent (CO_2e)	18	MMBtu/hr, each	12675	TONS/YR	EACH	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan and implement various design and operational efficiency requirements.
LA-0364	FG LA COMPLEX	PR Waste Heat Boiler	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	94	mm btu/h	455475	T/YR		Use of natural gas or fuel gas as fuel, energy-efficient design options, and operational/maintenance practices.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Auxiliary Boiler	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	80	mm BTU/h	117	LB/MM BTU		Good combustion practices; compliance with 40 CFR 63 Subpart DDDDD.
MI-0420	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FGAUXBOILERS	06/03/2016	Carbon Dioxide Equivalent (CO_2e)	6	MMBTU/H	6155	T/YR	12-MO ROLLING TIME PERIOD	Use of pipeline quality natural gas and energy efficiency measures.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUAUXBOILER (Auxiliary boiler)	12/05/2016	Carbon Dioxide Equivalent (CO_2e)	83.5	MMBTU/H	43283	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0426	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGAUXBOILERS (6 auxiliary boilers EUAUXBOIL2A, EUAUXBOIL3A, EUAUXBOIL2B, EUAUXBOIL3B, EUAUXBOIL2C, EUAUXBOIL3C)	03/24/2017	Carbon Dioxide Equivalent (CO_2e)	3	MMBTU/H	7324	T/YR	COMBINED FOR ALL BOILERS	Use of pipeline quality natural gas and energy efficiency measures.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (North Plant): Auxiliary Boilder	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/H	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/h	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUAUXBOILER: Auxiliary Boiler	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	99.9	MMBTU/H	25623	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures, use of natural gas.
MI-0441	LBWL--ERICKSON STATION	EUAUXBOILER--natural gas fired auxiliary boiler rated at <= 99MMBTU/H	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	99	MMBTU/H	50776	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGAUXBOILER	08/21/2019	Carbon Dioxide Equivalent (CO_2e)	80	MMBTU/H	41031	T/YR	12-MO ROLLING TIME PERIOD; EACH BOILER	Energy efficiency

Table D-2.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0447	LBWL--ERICKSON STATION	EUAUXBOILER--nat gas fired auxiliary boiler	01/07/2021	Carbon Dioxide Equivalent (CO_2e)	50	MMBTU/H	25644	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
MI-0451	MEC NORTH, LLC	EUAUXBOILER (North Plant): Auxiliary Boiler	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/H	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy efficiency measures and the use of a low carbon fuel (pipeline quality natural gas).
MI-0452	MEC SOUTH, LLC	EUAUXBOILER (South Plant): Auxiliary Boiler	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	61.5	MMBTU/H	31540	T/YR	12-MO ROLLING TIME PERIOD	Energy Efficiency Measures and the use of a low carbon fuel (pipeline quality natural gas)
MI-0454	LBWL-ERICKSON STATION	EUAUXBOILER--natural-gas fired auxiliary boiler, rated at less than or equal to 99 MMBTU/H	12/20/2022	Carbon Dioxide Equivalent (CO_2e)	50	MMBTU/H	25644	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
NY-0103	CRICKET VALLEY ENERGY CENTER	Auxiliary boiler	02/03/2016	Carbon Dioxide Equivalent (CO_2e)	60	MMBTU/H	119	LB/MMBTU	12 MO	good combustion practiced and pipeline quality natural gas
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Auxiliary Boiler (B001)	08/25/2015	Carbon Dioxide Equivalent (CO_2e)	34	MMBTU/H	4008	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion controls/natural gas combustion
OH-0367	SOUTH FIELD ENERGY LLC	Auxiliary Boiler (B001)	09/23/2016	Carbon Dioxide Equivalent (CO_2e)	99	MMBTU/H	32171	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion controls, natural gas combustion, and ultra low sulfur diesel
OH-0370	TRUMBULL ENERGY CENTER	Auxiliary Boiler (B001)	09/07/2017	Carbon Dioxide Equivalent (CO_2e)	37.8	MMBTU/H	4456	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion controls/natural gas combustion
OH-0372	OREGON ENERGY CENTER	Auxiliary Boiler (B001)	09/27/2017	Carbon Dioxide Equivalent (CO_2e)	37.8	MMBTU/H	4502	T/YR	PER ROLLING 12 MONTH PERIOD	use of natural gas, good combustion controls
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Auxiliary Boiler (B001)	11/07/2017	Carbon Dioxide Equivalent (CO_2e)	26.8	MMBTU/H	7845	T/YR	PER ROLLING 12 MONTH PERIOD	Natural gas as the sole fuel
OH-0377	HARRISON POWER	Auxiliary Boiler (B001)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	44.55	MMBTU/H	2817.6	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion practices and pipeline quality natural gas
OH-0377	HARRISON POWER	Auxiliary Boiler (B002)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	80	MMBTU/H	5009.1	T/YR	PER ROLLING 12 MONTH PERIOD	Good combustion practices and pipeline quality natural gas
OH-0379	PETMIN USA INCORPORATED	Startup boiler (B001)	02/06/2019	Carbon Dioxide Equivalent (CO_2e)	15.17	MMBTU/H	1784	LB/H		Good combustion practices and the use of natural gas
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Auxillary Boiler	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	13.31	MMBtu/hr	44107	TON	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	Auxilary Boiler	09/01/2015	Carbon Dioxide Equivalent (CO_2e)	55.4	MMBtu/hr	13561	TPY	12-MONTH ROLLING BASIS	
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Carbon Dioxide Equivalent (CO_2e)	95.7	MMBTU/H	119195	T/YR		Good combustion practices and use of low carbon fuel
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces	11/06/2015	Carbon Dioxide Equivalent (CO_2e)	13.2	MMBTU/H	6850	T/YR		Good combustion practice to ensure complete combustion.

Table D-2.7 Summary of CO_2e BACT Determinations for Auxiliary Boilers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0975	Freestone Peakers Plant	Simple Cycle Gas Turbines	6/13/2024	Carbon Dioxide Equivalent (CO_2e)	221	MW	800.0	LB/MWH Base Load		Good Combustion Practices
VA-0333	NORFOLK NAVAL SHIPYARD	Three (3) boilers	12/09/2020	Carbon Dioxide Equivalent (CO_2e)	76.6	MMBtu/hr	117.1	LB	MMBTU	
WI-0266	GREEN BAY PACKAGING, INC. - SHIPPING CONTAINER DIVISION	Natural gas-fied boiler (Boiler B01)	09/06/2018	Carbon Dioxide Equivalent (CO_2e)	35	mmBtu/hr	160	LBCO2E/1000 LB STEAM		Good combustion practices, use only natural gas, equip with Low NOx burners and flue gas recirculation
WI-0283	AFE, INC. LCM PLANT	B01-B12, Boilers	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	28	mmBTU/hr	160	LB/1000 LB CO2E	12-MONTH AVERAGE	Ultra-low NOx Burners, Flue Gas Recirculation, Good Combustion Practices and the Use of Pipeline Quality Natural Gas
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	B13-B24 & B25-B36 Natural Gas-Fired Boilers	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	28	mmBTU	160	LB CO2E/1000LB STEAM	12 MONTH AVERAGE	Ultra-Low NOx Burners, Flue Gas Recirculation, and Good Combustion Practices and the Use of Pipeline Quality Natural Gas.
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Carbon Dioxide Equivalent (CO_2e)	8.5	MMBtu/H	90	% AVG THERM EFF		Use only natural gas.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Natural Gas-Fired Auxiliary Boiler (B02)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	100	MMBTU/H	160	LB/MMBTU	12-MONTH ROLLING AVG.	Ultra-low NOx burners and flue gas recirculation. Operate and maintain boiler according to manufacturer's recommendations. Only use pipeline quality natural gas.
WI-0303	GREEN BAY PACKAGING INC.- GB MILL DIV.	Natural Gas-Fired Boiler (B01)	07/14/2020	Carbon Dioxide Equivalent (CO_2e)	32.7	MMBTU/H	16771	T/Y	ANY CONSECUTIVE 12-MONTH PERIOD	Only burn natural gas, good combustion practices, low NOx burner, and flue gas recirculation.
WI-0305	WPL- RIVERSIDE ENERGY CENTER	Natural Gas Auxiliary Boiler (B22)	01/22/2021	Carbon Dioxide Equivalent (CO_2e)	83.5	MMBTU/H	157	LB CO2/MMBTU	ANY MONTH, AVG ANY CONSECUTIVE 12-MONTHS	Combust only pipeline quality natural gas.
WI-0306	WPL- RIVERSIDE ENERGY CENTER	Temporary Boiler (B98A)	02/28/2020	Carbon Dioxide Equivalent (CO_2e)	14.67	MMBTU/H	118	LB CO2/MMBTU	HEAT INPUT	Combust only pipeline quality natural gas.
*WV-0029	HARRISON COUNTY POWER PLANT	Auxiliary Boiler	03/27/2018	Carbon Dioxide Equivalent (CO_2e)	77.8	mmBtu/hr	9107	LB/HR		Use of Natural Gas
*WV-0031	MOCKINGBIRD HILL COMPRESSOR STATION	WH-1 - Boiler	06/14/2018	Carbon Dioxide Equivalent (CO_2e)	8.72	mmBtu/hr	0			Limited to natural gas; and tune-up the boiler once every five years.
*WV-0032	BROOKE COUNTY POWER PLANT	Auxiliary Boiler	09/18/2018	Carbon Dioxide Equivalent (CO_2e)	111.9	mmBtu/hr	14768	LB/HR		Use of Natural Gas

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Nitrogen Oxides (NO_x)	32	MMBtu/hr	0.036	LB/MMBTU	3-HOUR AVERAGE	Low NOx Burners, Good Combustion Practices, Limited Operation of 500 hours per year per heater.
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Nitrogen Oxides (NO_x)	10	MMBtu/hr	0.011	LB/MMBTU	3 HOUR AVG	
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Nitrogen Oxides (NO_x)	78.2	MMBTU/HR	0.035	LB/MMBTU		SCR, LOW NOX BURNERS, AND COMBUSTION OF CLEAN FUEL AND
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Nitrogen Oxides (NO_x)	0		0.035	LB/MMBTU		SCR, LOW NOX BURNERS, AND COMBUSTION OF CLEAN FUEL
AR-0167	LION OIL COMPANY	SN-803 - #4 Pre-Flash Column Reboiler	12/01/2020	Nitrogen Oxides (NO_x)	40	MMBtu/hr	1.9	LB/HR	3-HOUR AVERAGE	Ultra-low NOx burners and good combustion practice
AR-0167	LION OIL COMPANY	SN-808 - #7 FCCU Furnace	12/01/2020	Nitrogen Oxides (NO_x)	56	MMBtu/hr	2.8	LB/HR	3-HOUR AVERAGE	Good combustion practice
AR-0167	LION OIL COMPANY	SN-810 - #9 Hydrotreater Furnace/Reboiler	12/01/2020	Nitrogen Oxides (NO_x)	70	MMBtu/hr	12.7	LB/HR	3-HOUR AVERAGE	

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0167	LION OIL COMPANY	SN-842 - #12 Unit Distillate Hydrotreater	12/01/2020	Nitrogen Oxides (NO_x)	50	MMBtu/hr	5.3	LB/HR	3-HOUR AVERAGE	Good combustion practice
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Nitrogen Oxides (NO_x)	58	MMBtu/hr	0.1	LB/MMBTU		Low NOx burners SCR Combustion of clean fuel Good Combustion Practices
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Nitrogen Oxides (NO_x)	150.5	MMBtu/hr	0.035	LB/MMBTU		SCR, Low NOx burners Combustion of clean fuel Good Combustion Practices
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Nitrogen Oxides (NO_x)	0		0.0032	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Nitrogen Oxides (NO_x)	75	MMBtu/hr	0.1	LB/MMBTU		Low NOx burners Combustion of clean fuel Good Combustion Practices
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Two natural gas heaters	03/09/2016	Nitrogen Oxides (NO_x)	10	MMBtu/hr	0.1	LB/MMBTU		Must have NOx emission design value less than 0.1 lb/MMBtu
FL-0363	DANIA BEACH ENERGY CENTER	Two natural gas heaters	12/04/2017	Nitrogen Oxides (NO_x)	9.9	MMBtu/hr	0.1	LB/MMBTU	DESIGN VALUE	Manufacturer certification
IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Nitrogen Oxides (NO_x)	47.7	mmBtu/hr	0.07	LB/MMBTU	3-HR AVG	LNB, good burner design, and GCP
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Nitrogen Oxides (NO_x)	70	MMBTU/HR	12.611	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Nitrogen Oxides (NO_x)	0		0.05	LB/MMBTU	UNITS 1-6, COMBUSTING NATURAL GAS	
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Nitrogen Oxides (NO_x)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Nitrogen Oxides (NO_x)	5.12	MMBtu/hr	50	LB/MMSCF		low NOx burners, good combustion practices and only pipeline quality natural gas shall be combusted
IN-0371	WABASH VALLEY RESOURCES, LLC	Dewpoint Heater	01/11/2024	Nitrogen Oxides (NO_x)	1.44	MMBtu/hr	50	LB/MMSCF		Low NOx burners and good combustion practices
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Nitrogen Oxides (NO_x)	2	mmBTU/hr	0.2	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Nitrogen Oxides (NO_x)	45.2	MMBTU/H	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Nitrogen Oxides (NO_x)	69	MMBTU/H	0.04	LB/MMBTU	30 DAY ROLLING AVERAGE	Ultra Low NOx Burners
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Nitrogen Oxides (NO_x)	37	MMBtu/hr, each	181.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.18 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Nitrogen Oxides (NO_x)	17.5	MMBtu/hr, each	81.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Nitrogen Oxides (NO_x)	54	MMBtu/hr	158	LB/MMSCF	FLAMELESS MODE	Low-Nox Burner (Designed to maintain 0.15 lb/MMBtu in flameless mode and 0.25 lb/MMBtu in flame mode); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Nitrogen Oxides (NO_x)	48	MMBtu/hr	70	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.07 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Nitrogen Oxides (NO_x)	28	MMBtu/hr, each	81.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A &; B	07/23/2020	Nitrogen Oxides (NO_x)	60	MMBtu/hr, combined	81.6	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.08 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Nitrogen Oxides (NO_x)	40	MMBtu/hr, combined	70	LB/MMSCF		Low-Nox Burner (Designed to maintain 0.07 lb/MMBtu); and a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Nitrogen Oxides (NO_x)	40	MMBtu/hr, total	100	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Nitrogen Oxides (NO_x)	23	MMBtu/hr	50	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also required to be equipped with low-NOx burners (0.07 lb/MMBtu).
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Nitrogen Oxides (NO_x)	4.8	MMBtu/hr, each	50	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with low-NOx burners.

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Nitrogen Oxides (NO_x)	94	MMBtu/hr	7.5	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also equipped with a SCR/SNCR system to control emissions. During a cold start, SCR does not reach operating temperature for approximately 30 minutes. During this time, only low-NOx burners are controlling emissions of NOx. NSG estimates the unit may undergo 1 cold start every two (2) weeks.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Nitrogen Oxides (NO_x)	36	MMBtu/hr	7.5	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is also equipped with a SCR/SNCR system to control emissions. During a cold start, SCR does not reach operating temperature for approximately 30 minutes. During this time, only low-NOx burners are controlling emissions of NOx. NSG estimates the unit may undergo 1 cold start every two (2) weeks.
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Nitrogen Oxides (NO_x)	3	MMBtu/hr	70	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. This unit is equipped with a low-NOx burner.
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Nitrogen Oxides (NO_x)	65.5	MMBtu/hr	70	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan. Equipped with low NOx burners (0.07 lb/MMBtu).

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Nitrogen Oxides (NO_x)	53	MMBtu/hr (total)	5.3	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Nitrogen Oxides (NO_x)	3	MMBtu/hr (total)	0.3	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Nitrogen Oxides (NO_x)	19.2	MMBtu/hr (total)	1.92	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Nitrogen Oxides (NO_x)	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Nitrogen Oxides (NO_x)	0		0			good engineering design and practices and use of clean fuels
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Nitrogen Oxides (NO_x)	7.37	mm btu/hr	0			good combustion practices
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Nitrogen Oxides (NO_x)	16.13	mm btu/hr	0			ULNB and Good Combustion Practices
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Nitrogen Oxides (NO_x)	0		0.06	LB/MMBTU		LNB
LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Nitrogen Oxides (NO_x)	90	mm btu/hr	0.01	LB/MM BTU	ANNUAL	Ultra-low NOx burners

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Nitrogen Oxides (NO_x)	34	MMBTU/H	0.05	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Low NOx burners and good design and combustion practices.
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Nitrogen Oxides (NO_x)	27	MMBTU/H	2.65	LB/H	HOURLY; EACH UNIT	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Nitrogen Oxides (NO_x)	3.7	MMBTU/H	0.55	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Nitrogen Oxides (NO_x)	38	MMBTU/H	0.05	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices, Low NOx burners.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Nitrogen Oxides (NO_x)	20.8	MMBTU/H	0.75	LB/H	HOURLY	Low NOx burner
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Nitrogen Oxides (NO_x)	3.8	MMBTU/H	0.14	LB/H	HOURLY	Low NOx burner
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Nitrogen Oxides (NO_x)	25	MMBTU/H	0.05	LB/MMBTU	HOURLY; EACH HEATER	Low NOx burners and good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Nitrogen Oxides (NO_x)	7	MMBTU/H	0.036	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices and low NOx burners
MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Nitrogen Oxides (NO_x)	27	MMBTU/H	1.32	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Nitrogen Oxides (NO_x)	38	MMBTU/H	0.05	LB/MMBTU	HOURLY	Good design and combustion practices, low NOx burners
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Nitrogen Oxides (NO_x)	100	MMBTU/H	10	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing)
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Nitrogen Oxides (NO_x)	15	MMBTU/H	0.3	LB/H		Low-NOx gas burner
OH-0379	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	02/06/2019	Nitrogen Oxides (NO_x)	15	MMBTU/H	2.12	LB/H		Good combustion practices and the use of natural gas

Table D-3.1 Summary of NO_x BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Nitrogen Oxides (NO_x)	88	MMBTU/H	6.16	LB/H		Use of natural gas, use of low NOx burners, good combustion practices and design
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Nitrogen Oxides (NO_x)	0		0.1	LB/MMBTU		Natural Gas Fuel
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Nitrogen Oxides (NO_x)	3	MMBTU/H	0.1	LB/MMBTU	1 HOUR	
TX-0755	RAMSEY GAS PLANT	Hot Oil Heaters and Regeneration Heaters	05/21/2015	Nitrogen Oxides (NO_x)	60	MMBTU/H	0.045	LB/MMBTU		low NOx burners
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Nitrogen Oxides (NO_x)	40	MMBTU/H	0.036	LB/MMBTU		Low NOx burners
TX-0845	ARKEMA BEAUMONT PLANT	HEATERS	08/24/2018	Nitrogen Oxides (NO_x)	31	BTU/HR	0.04	LB/MMBTU		LOW NOX BURNERS, CLEAN FUEL
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Nitrogen Oxides (NO_x)	100	MMBtu	0.04	LB/MMBTU		Low NOx burners and good combustion practice.
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HEATER NO 2	03/14/2023	Nitrogen Oxides (NO_x)	0		0.01	LB/MMBTU	1-HR	Burner design for good combustion efficiency and to minimize NOx formation.
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HOT OIL HEATER	03/14/2023	Nitrogen Oxides (NO_x)	0		0.014	LB/MMBTU	1-HR	Burner design for good combustion efficiency and to minimize NOx formation with a SCR system to further reduce NOx.
TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Nitrogen Oxides (NO_x)	0		9	PPMVD		LOW NOX BURNERS
WI-0291	GRAYMONT WESTERN LIME-EDEN	P05 Natural Gas Fired Line Heater	01/28/2019	Nitrogen Oxides (NO_x)	1.5	mmBTU/hr	0.1	LB/MMBTU		Good Combustion Practices

Table D-3.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Carbon Monoxide	32	MMBtu/hr	0.087	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
AL-0329	COLBERT COMBUSTION TURBINE PLANT	Three Gas Heaters	09/21/2021	Carbon Monoxide	10	MMBtu/hr	0.08	LB/MMBTU	3 HOUR AVG	
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Carbon Monoxide	78.2	MMBTU/HR	0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Carbon Monoxide	0		0.0824	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Carbon Monoxide	58	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Carbon Monoxide	150.5	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Carbon Monoxide	0		0.08	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Carbon Monoxide	75	MMBtu/hr	0.0824	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Carbon Monoxide	47.7	mmBtu/hr	0.0194	LB/MMBTU	3-HR AVG	GCP and good burner design
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Carbon Monoxide	70	MMBTU/HR	2.556	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Carbon Monoxide	0		0.038	LB/MMBTU	WHEN COMBUSTING NATURAL GAS	
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Carbon Monoxide	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Carbon Monoxide	5.12	MMBtu/hr	84	LB/MMSCF		good combustion practices
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Carbon Monoxide	2	mmBTU/hr	0.16	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Carbon Monoxide	45.2	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Carbon Monoxide	69	MMBTU/H	0.035	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners

Table D-3.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Carbon Monoxide	37	MMBtu/hr, each	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Carbon Monoxide	17.5	MMBtu/hr, each	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Carbon Monoxide	54	MMBtu/hr	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Carbon Monoxide	48	MMBtu/hr	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Carbon Monoxide	28	MMBtu/hr, each	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Carbon Monoxide	60	MMBtu/hr, combined	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Carbon Monoxide	40	MMBtu/hr, combined	84	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Carbon Monoxide	40	MMBtu/hr, total	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Carbon Monoxide	23	MMBtu/hr	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Carbon Monoxide	4.8	MMBtu/hr, each	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Carbon Monoxide	94	MMBtu/hr	84	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan.

Table D-3.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Carbon Monoxide	36	MMBtu/hr	84	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Carbon Monoxide	3	MMBtu/hr	84	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Carbon Monoxide	65.5	MMBtu/hr	84	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Carbon Monoxide	53	MMBtu/hr (total)	4.45	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Carbon Monoxide	3	MMBtu/hr (total)	0.25	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Carbon Monoxide	19.2	MMBtu/hr (total)	1.61	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Carbon Monoxide	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of clean fuels
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Carbon Monoxide	0		0			good engineering design and practices and use of clean fuels
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Carbon Monoxide	7.37	mm btu/hr	0			good combustion practices
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Carbon Monoxide	16.13	mm btu/hr	0			Good Combustion Practices
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Carbon Monoxide	0		0.037	LB/MMBTU		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD.
LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Carbon Monoxide	90	mm btu/hr	0.037	LB/MM BTU	ANNUAL	Proper burner design and operations Good combustion practices Compliance with 40 CFR 63 Subpart
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Carbon Monoxide	34	MMBTU/H	0.082	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good design and operation
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 &	01/04/2017	Carbon Monoxide	27	MMBTU/H	2.22	LB/H	HOURLY; EACH UNIT	Good combustion practices.

Table D-3.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Carbon Monoxide	3.7	MMBTU/H	0.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Carbon Monoxide	38	MMBTU/H	0.082	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good design and operation.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Carbon Monoxide	20.8	MMBTU/H	0.77	LB/H	HOURLY	Good combustion controls.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Carbon Monoxide	3.8	MMBTU/H	0.14	LB/H	HOURLY	Good combustion controls
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Carbon Monoxide	25	MMBTU/H	0.08	LB/MMBTU	HOURLY; EACH HEATER	Good combustion practices.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Carbon Monoxide	7	MMBTU/H	0.037	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Carbon Monoxide	27	MMBTU/H	1.11	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Carbon Monoxide	38	MMBTU/H	0.082	LB/MMBTU	HOURLY	Good design and operation
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Carbon Monoxide	100	MMBTU/H	8.24	LB/H		good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing)
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Carbon Monoxide	15	MMBTU/H	0.83	LB/H		Combustion control
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Carbon Monoxide	88	MMBTU/H	6.16	LB/H		Use natural gas, use of baffle type burners, good combustion practices and design
OH-0383	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	07/17/2020	Carbon Monoxide	15	MMBTU/H	0.521	LB/H		Good combustion practices and the use of natural gas
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Carbon Monoxide	0		0.084	LB/MMBTU		Natural Gas Fuel.
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Carbon Monoxide	3	MMBTU/H	0.04	LB/MMBTU	1 HOUR	
TX-0755	RAMSEY GAS PLANT	Hot Oil Heaters and Regeneration Heaters	05/21/2015	Carbon Monoxide	60	MMBTU/H	50	PPMVD @ 3% O2		Good combustion practices and firing of residue gas with low carbon content
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Carbon Monoxide	40	MMBTU/H	50	PPMVD @ 3% O2		Good combustion practice to ensure complete combustion.
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Carbon Monoxide	100	MMBtu	50	PPMVD	3% O2	Good combustion practice and proper design.

Table D-3.2 Summary of CO BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	Water Bath Heater	03/13/2023	Carbon Monoxide	16.8	MMBTU/HR	50	PPMVD	3% O2	Good combustion practices
TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Carbon Monoxide	0		50	PPMVD	3% O2	Good combustion practices and fire hydrogenrich plant fuel gas
WI-0291	GRAYMONT WESTERN LIME-EDEN	P05 Natural Gas Fired Line Heater	01/28/2019	Carbon Monoxide	1.5	mmBTU/hr	0.082	LB/MMBTU		Good Combustion Practices

Table D-3.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Volatile Organic Compounds (VOC)	32	MMBtu/hr	0.0057	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Volatile Organic Compounds (VOC)	78.2	MMBTU/HR	0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Volatile Organic Compounds (VOC)	58	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Volatile Organic Compounds (VOC)	150.5	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Volatile Organic Compounds (VOC)	0		0.01	LB/MMBTU		Combustion of Natural Gas and Good Combustion Practices
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Volatile Organic Compounds (VOC)	75	MMBtu/hr	0.0054	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
FL-0364	SEMINOLE GENERATING STATION	Two natural gas heaters (< 10 MMBtu/hr each)	03/21/2018	Volatile Organic Compounds (VOC)	9.9	MMBtu/hr	0.005	LB/MMBTU		
IL-0127	WINPAK HEAT SEAL CORPORATION	Heating Units	10/05/2018	Volatile Organic Compounds (VOC)	1	mmBtu/hr	0			Units shall be operated in accordance with good combustion practices.
IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Volatile Organic Compounds (VOC)	47.7	mmBtu/hr	0.0014	LB/MMBTU	3-HR AVG	GCP and good burner design
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Volatile Organic Compounds (VOC)	70	MMBTU/HR	0.378	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0285	WHITING CLEAN ENERGY, INC.	Space Heaters	08/02/2017	Volatile Organic Compounds (VOC)	0		0.0053	LB/MMBTU	WHEN COMBUSTING NATURAL GAS	
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Volatile Organic Compounds (VOC)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, good combustion practices
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Volatile Organic Compounds (VOC)	5.12	MMBtu/hr	5.5	LB/MMSCF		good combustion practices
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Volatile Organic Compounds (VOC)	2	mmBTU/hr	0.011	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Volatile Organic Compounds (VOC)	45.2	MMBTU/H	0.0015	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Volatile Organic Compounds (VOC)	69	MMBTU/H	0.0015	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners

Table D-3.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Volatile Organic Compounds (VOC)	37	MMBtu/hr, each	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Volatile Organic Compounds (VOC)	17.5	MMBtu/hr, each	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Volatile Organic Compounds (VOC)	54	MMBtu/hr	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Volatile Organic Compounds (VOC)	48	MMBtu/hr	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Volatile Organic Compounds (VOC)	28	MMBtu/hr, each	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Volatile Organic Compounds (VOC)	60	MMBtu/hr, combined	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Volatile Organic Compounds (VOC)	40	MMBtu/hr, combined	5.5	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Volatile Organic Compounds (VOC)	40	MMBtu/hr, total	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Volatile Organic Compounds (VOC)	23	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Volatile Organic Compounds (VOC)	4.8	MMBtu/hr, each	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Volatile Organic Compounds (VOC)	94	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Volatile Organic Compounds (VOC)	36	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Volatile Organic Compounds (VOC)	3	MMBtu/hr	5.5	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Volatile Organic Compounds (VOC)	65.5	MMBtu/hr	5.5	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Volatile Organic Compounds (VOC)	53	MMBtu/hr (total)	0.29	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan

Table D-3.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Volatile Organic Compounds (VOC)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Volatile Organic Compounds (VOC)	19.2	MMBtu/hr (total)	0.11	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Volatile Organic Compounds (VOC)	7.37	mm btu/hr	0			good combustion practices
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Volatile Organic Compounds (VOC)	16.13	mm btu/hr	0.0054	LB/MM BTU		Good Combustion Practices and Use of low sulfur facility fuel gas
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Volatile Organic Compounds (VOC)	0		4.02	LB/H		Good combustion practices and compliance with the applicable provisions of 40 CFR 63 Subpart DDDDD.
LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Volatile Organic Compounds (VOC)	90	mm btu/hr	0.0054	LB/MM BTU	ANNUAL	Proper burner design and operations Good combustion practices Compliance with 40 CFR 63 Subpart DDDDD
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Volatile Organic Compounds (VOC)	34	MMBTU/H	0.0054	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good design and operating/combustion practices.
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Volatile Organic Compounds (VOC)	27	MMBTU/H	0.15	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Volatile Organic Compounds (VOC)	3.7	MMBTU/H	0.03	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Volatile Organic Compounds (VOC)	38	MMBTU/H	0.0054	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good design and operating/combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Volatile Organic Compounds (VOC)	20.8	MMBTU/H	0.17	LB/H	HOURLY	Good combustion controls
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Volatile Organic Compounds (VOC)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Good combustion controls.
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Volatile Organic Compounds (VOC)	25	MMBTU/H	0.005	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Volatile Organic Compounds (VOC)	7	MMBTU/H	0.025	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Volatile Organic Compounds (VOC)	27	MMBTU/H	0.07	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Volatile Organic Compounds (VOC)	38	MMBTU/H	0.0054	LB/MMBTU	HOURLY	Good design and operating/combustion practices
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Volatile Organic Compounds (VOC)	100	MMBTU/H	0.54	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing).

Table D-3.3 Summary of VOC BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Volatile Organic Compounds (VOC)	15	MMBTU/H	0.075	LB/H		Combustion control
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Volatile Organic Compounds (VOC)	88	MMBTU/H	0.48	LB/H		Use of natural gas, good combustion practices and design
OK-0164	MIDWEST CITY AIR DEPOT	Heaters/Boilers	01/08/2015	Volatile Organic Compounds (VOC)	0	MMBTUH	7.1	TONS PER YEAR	TOTAL FOR ALL UNITS.	1. Use pipeline-quality natural gas. 2. Good Combustion Practices w/emission rate limit of 0.005 lb/MMBTU based on AP-42 (7/1998).
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Volatile Organic Compounds (VOC)	0		0.0055	LB/MMBTU		Natural Gas Fuel.
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Volatile Organic Compounds (VOC)	1.83	MMBTU/H	0.01	LB/H		NATURAL GAS USAGE AND GOOD COMBUSTION PRACTICES.
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Volatile Organic Compounds (VOC)	40	MMBTU/H	0.94	T/YR		Good combustion practice to ensure complete combustion.
TX-0877	SWEENY REFINERY	Isostripper Reboiler (heater)	01/08/2020	Volatile Organic Compounds (VOC)	0		0.0054	LB/MMBTU		Good combustion practices, use of natural gas fuel for the project heater
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Volatile Organic Compounds (VOC)	100	MMBtu	0.0054	LB/MMBTU		Good combustion practice and proper design.
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	Water Bath Heater	03/13/2023	Volatile Organic Compounds (VOC)	16.8	MMBTU/HR	0.005	LB/MMBTU		Good combustion practices
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HEATER NO 2	03/14/2023	Volatile Organic Compounds (VOC)	0		0			Burner design for good combustion efficiency
TX-0955	INEOS OLIGOMERS CHOCOLATE BAYOU	HOT OIL HEATER	03/14/2023	Volatile Organic Compounds (VOC)	0		0			Burner design for high efficiency combustion.
WI-0292	GREEN BAY PACKAGING INC. MILL DIVISION	P44 Space Heaters	04/01/2019	Volatile Organic Compounds (VOC)	20	mmBTU/hr	0.0055	LB/MMBTU		Good Combustion Practices, the Use of Low-NOx Burners
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Natural Gas-Fired Space Heaters (P44)	12/10/2019	Volatile Organic Compounds (VOC)	8.5	MMBtu/H	0.0055	LB/MMBTU		

Table D-3.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Particulate matter, filterable (FPM)	78.2	MMBTU/HR	0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, filterable (FPM)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, filterable (FPM)	0		0.0079	GR/DSCF		Dust Collector and Scrubber
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Particulate matter, filterable (FPM)	75	MMBtu/hr	0.0075	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Particulate matter, filterable (FPM)	70	MMBTU/HR	0.13	LB/H	3HR AVERAGE	GOOD COMBUSTION PRACTICE
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, filterable (FPM)	5.12	MMBtu/hr	1.9	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Particulate matter, filterable (FPM)	37	MMBtu/hr, each	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Particulate matter, filterable (FPM)	17.5	MMBtu/hr, each	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Particulate matter, filterable (FPM)	54	MMBtu/hr	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Particulate matter, filterable (FPM)	48	MMBtu/hr	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Particulate matter, filterable (FPM)	28	MMBtu/hr, each	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Particulate matter, filterable (FPM)	60	MMBtu/hr, combined	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Particulate matter, filterable (FPM)	40	MMBtu/hr, combined	1.9	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Particulate matter, filterable (FPM)	40	MMBtu/hr, total	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan

Table D-3.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Particulate matter, filterable (FPM)	23	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, filterable (FPM)	4.8	MMBtu/hr, each	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Particulate matter, filterable (FPM)	94	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Particulate matter, filterable (FPM)	36	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, filterable (FPM)	3	MMBtu/hr	1.9	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Particulate matter, filterable (FPM)	65.5	MMBtu/hr	1.9	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Particulate matter, filterable (FPM)	53	MMBtu/hr (total)	0.1	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, filterable (FPM)	3	MMBtu/hr (total)	0.006	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041c - Indirect-Fired Building Heating Systems & 1 MMBtu	07/25/2022	Particulate matter, filterable (FPM)	19.2	MMBtu/hr (total)	0.04	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Particulate matter, filterable (FPM)	34	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Particulate matter, filterable (FPM)	27	MMBTU/H	0.002	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, filterable (FPM)	3.7	MMBTU/H	0.007	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Particulate matter, filterable (FPM)	38	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good combustion practices
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Particulate matter, filterable (FPM)	20.8	MMBTU/H	0.15	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, filterable (FPM)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Particulate matter, filterable (FPM)	25	MMBTU/H	0.002	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Particulate matter, filterable (FPM)	27	MMBTU/H	0.002	LB/MMBTU	HOURLY; EACH FUEL HEATER	Good combustion practices

Table D-3.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Particulate matter, filterable (FPM)	38	MMBTU/H	0.0075	LB/MMBTU	HOURLY	Good combustion practices
TX-0888	ORANGE POLYETHYLENE PLANT	Heaters	04/23/2020	Particulate matter, filterable (FPM)	100	MMBtu	0.0075	LB/MMBTU		Good combustion practice, clean fuel, and proper design.
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	Water Bath Heater	03/13/2023	Particulate matter, filterable (FPM)	16.8	MMBTU/HR	0.007	LB/MMBTU		Good combustion practices
TX-0964	NEDERLAND FACILITY	HEATERS	10/05/2023	Particulate matter, filterable (FPM)	0		0			Good combustion practices and fire hydrogenrich plant fuel gas, 5% OPACITY

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Particulate matter, total (TPM10)	32	MMBtu/hr	0.0079	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
AK-0085	GAS TREATMENT PLANT	Two (2) Buyback Gas Bath Heaters and Three (3) Operations Camp Heaters	08/13/2020	Particulate matter, total (TPM2.5)	32	MMBtu/hr	0.0079	LB/MMBTU	3-HOUR AVERAGE	Good Combustion Practices, Clean Fuels, and Limited Operation of 500 hours per year per heater.
AR-0155	BIG RIVER STEEL LLC	PREHEATER, GALVANIZING LINE SN-28	11/07/2018	Particulate matter, total (TPM2.5)	78.2	MMBTU/HR	0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, total (TPM10)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0159	BIG RIVER STEEL LLC	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	04/05/2019	Particulate matter, total (TPM2.5)	0		0.0012	LB/MMBTU		COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION PRACTICE
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Particulate matter, total (TPM10)	58	MMBtu/hr	0.013	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0168	BIG RIVER STEEL LLC	Decarburizing Line Furnace Section	03/17/2021	Particulate matter, total (TPM2.5)	58	MMBtu/hr	0.013	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Particulate matter, total (TPM10)	150.5	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0168	BIG RIVER STEEL LLC	Galvanizing Line #2 Furnace	03/17/2021	Particulate matter, total (TPM2.5)	150.5	MMBtu/hr	0.0012	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, total (TPM10)	0		0.0079	GR/DSCF		Dust Collector and Scrubber
AR-0173	BIG RIVER STEEL LLC	Furnace Dedusting	01/31/2022	Particulate matter, total (TPM2.5)	0		0.0079	GR/DSCF		Dust Collector and Scrubber
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Particulate matter, total (TPM10)	75	MMBtu/hr	0.0075	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice
AR-0173	BIG RIVER STEEL LLC	Hydrogen Plant #2 Reformer Furnace	01/31/2022	Particulate matter, total (TPM2.5)	75	MMBtu/hr	0.0075	LB/MMBTU		Combustion of Natural gas and Good Combustion Practice

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Particulate matter, total (TPM10)	47.7	mmBtu/hr	0.0024	LB/MMBTU	3-HR AVG	GCP and good burner design
IL-0134	CRONUS CHEMICALS	Startup Heater	12/21/2023	Particulate matter, total (TPM2.5)	47.7	mmBtu/hr	0.0024	LB/MMBTU	3-HR AVG	GCP and good burner design
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Particulate matter, total (TPM10)	70	MMBTU/HR	0.522	LB/H	3HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0263	MIDWEST FERTILIZER COMPANY LLC	STARTUP HEATER EU-002	03/23/2017	Particulate matter, total (TPM2.5)	70	MMBTU/HR	0.522	LB/H	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Particulate matter, total (TPM10)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices
IN-0324	MIDWEST FERTILIZER COMPANY LLC	startup heater EU-002	05/06/2022	Particulate matter, total (TPM2.5)	33.34	MMBtu/hr	200	HR/YR	TWELVE CONSECUTIVE MONTH PERIOD	shall combust natural gas, shall be controlled by good combustion practices
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, total (TPM10)	5.12	MMBtu/hr	7.6	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
IN-0359	NUCOR STEEL	Hot Water Circuit Burner for Sheet Metal Coating Line	03/30/2023	Particulate matter, total (TPM2.5)	5.12	MMBtu/hr	7.6	LB/MMSCF		good combustion practices and only pipeline quality natural gas shall be combusted
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Particulate matter, total (TPM10)	2	mmBTU/hr	0.015	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Indirect fuel-gas heater	03/31/2016	Particulate matter, total (TPM2.5)	2	mmBTU/hr	0.015	LB/H	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Particulate matter, total (TPM10)	45.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B2031	10/30/2019	Particulate matter, total (TPM2.5)	45.2	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Particulate matter, total (TPM10)	69	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KS-0041	HOLLYFRONTIER EL DORADO REFINERY	B3401	10/30/2019	Particulate matter, total (TPM2.5)	69	MMBTU/H	0.0075	LB/MMBTU	3 HR ROLLING AVERAGE	Ultra Low NOx Burners
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Particulate matter, total (TPM10)	37	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-02 - Ingot Car Bottom Furnaces #1-#4	07/23/2020	Particulate matter, total (TPM2.5)	37	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Particulate matter, total (TPM10)	17.5	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 03-05 - Steckel Mill Coiling Furnaces #1 & #2	07/23/2020	Particulate matter, total (TPM2.5)	17.5	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Particulate matter, total (TPM10)	54	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-02 - Austenitizing Furnace	07/23/2020	Particulate matter, total (TPM2.5)	54	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Particulate matter, total (TPM10)	48	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 04-03 - Tempering Furnace	07/23/2020	Particulate matter, total (TPM2.5)	48	MMBtu/hr	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Particulate matter, total (TPM10)	28	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-01 - Group 1 Car Bottom Furnaces #1 - #3	07/23/2020	Particulate matter, total (TPM2.5)	28	MMBtu/hr, each	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Particulate matter, total (TPM10)	60	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 05-02 - Group 2 Car Bottom Furnaces A & B	07/23/2020	Particulate matter, total (TPM2.5)	60	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Particulate matter, total (TPM10)	40	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-01 - Natural Gas Direct-Fired Space Heaters, Process Water Heaters, & Air Makeup Heaters	07/23/2020	Particulate matter, total (TPM2.5)	40	MMBtu/hr, combined	7.6	LB/MMSCF		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Particulate matter, total (TPM10)	40	MMBtu/hr, total	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Makeup Air Units (EP 21-19)	04/19/2021	Particulate matter, total (TPM2.5)	40	MMBtu/hr, total	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Particulate matter, total (TPM10)	23	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Alkali Cleaning Section Heater (EP 21-07B)	04/19/2021	Particulate matter, total (TPM2.5)	23	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, total (TPM10)	4.8	MMBtu/hr, each	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Annealing Furnaces (15) (EP 21-15)	04/19/2021	Particulate matter, total (TPM2.5)	4.8	MMBtu/hr, each	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Particulate matter, total (TPM10)	94	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Preheat Furnace (EP 21-08A)	04/19/2021	Particulate matter, total (TPM2.5)	94	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Particulate matter, total (TPM10)	36	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Radiant Tube Furnace (EP 21-08B)	04/19/2021	Particulate matter, total (TPM2.5)	36	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, total (TPM10)	3	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Galvanizing Line #2 Zinc Pot Preheater (EP 21-09)	04/19/2021	Particulate matter, total (TPM2.5)	3	MMBtu/hr	7.6	LB/MMSCF		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Particulate matter, total < 10 Âµ (TPM10)	65.5	MMBtu/hr	7.6	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Heated Transfer Table Furnace (EP 02-03)	04/19/2021	Particulate matter, total (TPM2.5)	65.5	MMBtu/hr	7.6	LB/MMSCF	3-HR AVERAGE	The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Particulate matter, total (TPM10)	53	MMBtu/hr (total)	0.4	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041a - Direct-Fired Building Heating Systems	07/25/2022	Particulate matter, total (TPM2.5)	53	MMBtu/hr (total)	0.4	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total < 10 Âµ (TPM10)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total (TPM2.5)	3	MMBtu/hr (total)	0.02	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total < 10 Âµ (TPM10)	19.2	MMBtu/hr (total)	0.15	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 041b - Indirect-Fired Building Heating Systems 1 MMBtu	07/25/2022	Particulate matter, total (TPM2.5)	19.2	MMBtu/hr (total)	0.15	LB/HR	MONTHLY AVERAGE	Good Combustion & Operation Practices (GCOP) Plan
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Particulate matter, total (TPM10)	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of clean fuels
LA-0305	LAKE CHARLES METHANOL FACILITY	Gasifier Start-up Preheat Burners	06/30/2016	Particulate matter, total (TPM2.5)	23	MM BTU/hr (each)	0			good engineering practices, good combustion technology, and use of clean fuels
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Particulate matter, total (TPM10)	0		0			good engineering design and practices and use of clean fuels
LA-0305	LAKE CHARLES METHANOL FACILITY	WSA Preheat Burners	06/30/2016	Particulate matter, total (TPM2.5)	0		0			good engineering design and practices and use of clean fuels
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Particulate matter, total (TPM10)	7.37	mm btu/hr	0			good combustion practices
LA-0307	MAGNOLIA LNG FACILITY	Regenerative Heaters	03/21/2016	Particulate matter, total (TPM2.5)	7.37	mm btu/hr	0			good combustion practices
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Particulate matter, total (TPM2.5)	16.13	mm btu/hr	0.0075	LB/MM BTU		Good Combustion Practices and Use of low sulfur facility fuel gas
LA-0349	DRIFTWOOD LNG FACILITY	Hot Oil Heaters (5)	07/10/2018	Particulate matter, total (TPM10)	16.13	mm btu/hr	0.0075	LB/MM BTU		Good Combustion Practices and Use of low sulfur facility fuel gas

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Particulate matter, total (TPM10)	0		0.03	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
LA-0364	FG LA COMPLEX	Hot Oil Heaters 1 and 2	01/06/2020	Particulate matter, total (TPM2.5)	0		0.03	LB/H		Use of pipeline quality natural gas or fuel gas and good combustion practices.
LA-0398	CAMERON LNG FACILITY	Hot Oil Heaters (EQT0111, EQT0112, EQT0113)	09/19/2023	Particulate matter, total (TPM10)	90	mm btu/hr	0.0075	LB/MM BTU		Proper burner design and operations Good combustion practices Compliance with 40 CFR 63 Subpart DDDDD Fueled by natural gas
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Particulate matter, total (TPM10)	34	MMBTU/H	0.0005	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0421	GRAYLING PARTICLEBOARD	EUTOH (In FGTOH)--Thermal Oil Heater	08/26/2016	Particulate matter, total (TPM2.5)	34	MMBTU/H	0.0004	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Particulate matter, total (TPM10)	27	MMBTU/H	0.2	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices.
MI-0423	INDECK NILES, LLC	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	01/04/2017	Particulate matter, total (TPM2.5)	27	MMBTU/H	0.2	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, total (TPM10)	3.7	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFUELHTR (Fuel pre-heater)	12/05/2016	Particulate matter, total (TPM2.5)	3.7	MMBTU/H	0.0075	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Particulate matter, total (TPM10)	38	MMBTU/H	0.0005	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUTOH in FGTOH	05/09/2017	Particulate matter, total (TPM2.5)	38	MMBTU/H	0.0004	LB/MMBTU	TEST PROTOCOL SHALL SPECIFY	Good combustion practices.

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM10)	20.8	MMBTU/H	0.15	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR1: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM2.5)	20.8	MMBTU/H	0.15	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM10)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFUELHTR2: Natural gas fired fuel heater	07/16/2018	Particulate matter, total (TPM2.5)	3.8	MMBTU/H	0.03	LB/H	HOURLY	Low sulfur fuel
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Particulate matter, total (TPM10)	25	MMBTU/H	0.008	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
MI-0440	MICHIGAN STATE UNIVERSITY	FGFUELHEATERS	05/22/2019	Particulate matter, total (TPM2.5)	25	MMBTU/H	0.008	LB/MMBTU	HOURLY; EACH UNIT	Good combustion practices
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Particulate matter, total (TPM10)	7	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH UNIT	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion)
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGPREHEAT	08/21/2019	Particulate matter, total (TPM2.5)	7	MMBTU/H	7.6	LB/MMSCF	HOURLY; EACH UNIT	Low sulfur fuel (natural gas) and good combustion practices (efficient combustion).
MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Particulate matter, total (TPM10)	27	MMBTU/H	0.1	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0445	INDECK NILES, LLC	FGFUELHTR (2 fuel pre-heaters)	11/26/2019	Particulate matter, total (TPM2.5)	27	MMBTU/H	0.1	LB/H	HOURLY; EACH FUEL HEATER	Good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Particulate matter, total (TPM10)	38	MMBTU/H	0.0005	LB/MMBTU	HOURLY	Good combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Thermal oil heater (EUTOH in FGTOH)	12/18/2020	Particulate matter, total (TPM2.5)	38	MMBTU/H	0.0004	LB/MMBTU	HOURLY	Good combustion practices

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Particulate matter, total (TPM10)	100	MMBTU/H	0.75	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing).
OH-0368	PALLAS NITROGEN LLC	Startup Heater (B001)	04/19/2017	Particulate matter, total (TPM2.5)	100	MMBTU/H	0.75	LB/H		Good combustion control (i.e., high temperatures, sufficient excess air, sufficient residence times, and god air/fuel mixing)
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Particulate matter, total (TPM10)	15	MMBTU/H	0.075	LB/H		Combustion control
OH-0374	GUERNSEY POWER STATION LLC	Fuel Gas Heaters (2 identical, P007 and P008)	10/23/2017	Particulate matter, total (TPM2.5)	15	MMBTU/H	0.075	LB/H		Combustion control
OH-0379	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	02/06/2019	Particulate matter, total (TPM10)	15	MMBTU/H	0.112	LB/H		Good combustion practices and the use of natural gas
OH-0379	PETMIN USA INCORPORATED	Ladle Preheaters (P002, P003 and P004)	02/06/2019	Particulate matter, total (TPM2.5)	15	MMBTU/H	0.112	LB/H		Good combustion practices and the use of natural gas
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Particulate matter, total (TPM10)	88	MMBTU/H	0.88	LB/H		Use of natural gas, good combustion practices and design
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Tunnel Furnace #2 (P018)	09/27/2019	Particulate matter, total (TPM2.5)	88	MMBTU/H	0.88	LB/H		Use of natural gas, good combustion practices and design
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Particulate matter, total (TPM10)	0		0.0076	LB/MMBTU		Natural Gas Fuel.
OK-0173	CMC STEEL OKLAHOMA	Heaters (Gas-Fired)	01/19/2016	Particulate matter, total (TPM2.5)	0		0.0076	LB/MMBTU		Natural Gas Fuel.
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Particulate matter, total (TPM10)	1.83	MMBTU/H	0.01	LB/H		USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES
SC-0179	CAROLINA PARTICLEBOARD	THERMAL OIL HEATER #2	03/18/2015	Particulate matter, total (TPM2.5)	1.83	MMBTU/H	0.003	LB/H		NATURAL GAS USAGE AND GOOD COMBUSTION PRACTICES.
TX-0694	INDECK WHARTON ENERGY CENTER	heater	02/02/2015	Particulate matter, total (TPM2.5)	3	MMBTU/H	0			

Table D-3.5 Summary of Total PM10/PM2.5 BACT Determinations for Process Heaters

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Particulate matter, total (TPM10)	40	MMBTU/H	1.31	T/YR		Good combustion practice to ensure complete combustion. gaseous fuel
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Commercial/Institutional-Size Boilers/Furnaces (heater)	11/06/2015	Particulate matter, total < 2.5 Âµ (TPM2.5)	40	MMBTU/H	1.31	T/YR		Good combustion practice to ensure complete combustion. gaseous fuel

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Nitrogen Oxides (NO_x)	2695	hp	4.8	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Nitrogen Oxides (NO_x)	610	hp	3	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Nitrogen Oxides (NO_x)	891	hp	4.8	GRAMS/HP-H		
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Nitrogen Oxides (NO_x)	143.5	MMBtu/hr	0.53	G/KW-HR (ULSD)	3-HOUR AVERAGE	Selective Catalytic Reduction (SCR) and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Nitrogen Oxides (NO_x)	1500	kWe	8	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Nitrogen Oxides (NO_x)	186.6	gph	3.3	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, limit operation to 500 hours per year.
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Nitrogen Oxides (NO_x)	27.9	Gal/hr	3.6	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	DIESEL FIRED EMERGENCY GENERATOR	07/22/2014	Nitrogen Oxides (NOx)	800	HP	0.015	LB/HP-H		
AL-0328	PLANT BARRY	Diesel Emergency Engines	11/09/2020	Nitrogen Oxides (NO_x)	0		3	GR/BHP-HR	NMHC + NOX	
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Nitrogen Oxides (NO_x)	0		0.4	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Nitrogen Oxides (NO_x)	0		4.86	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Nitrogen Oxides (NO_x)	3634	Horsepower	5.6	G/KW-HR		
AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Nitrogen Oxides (NO_x)	0		3.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	Emergency Diesel Engine	09/16/2014	Nitrogen Oxides (NOx)	3300	hp	0			Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	Main Propulsion Generator Diesel Engines	09/16/2014	Nitrogen Oxides (NOx)	9910	hp	12.7	G/KW-H	ROLLING 24 HOUR AVERAGE	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure
FL-0350	ANADARKO PETROLEUM, INC DIAMOND BLACKHAWK DRILLING PROJECT	Main Propulsion Generator Engines	12/31/2014	Nitrogen Oxides (NO_x)	0		0			Use of good combustion practices based on the most recent manufacturers specifications issued for these engines at the time that the engines are operating under this permit
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	07/27/2018	Nitrogen Oxides (NO_x)	14.82	MMBtu/hour	6.4	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	06/07/2021	Nitrogen Oxides (NO_x)	14.82	MMBtu/hour	6.4	G/KW-HOUR	FOR NMHC+NOX	
IL-0114	CRONUS CHEMICALS, LLC	Emergency Generator	09/05/2014	Nitrogen Oxides (NOx)	3755	HP	0.67	G/KW-H		Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Nitrogen Oxides (NO_x)	1250	kW	6.4	GRAMS	KILOWATT-HOUR	
IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Nitrogen Oxides (NO_x)	3985	hp	6.4	G/KW-HR	3-HR AVG	
IN-0173	MIDWEST FERTILIZER CORPORATION	DIESEL FIRED EMERGENCY GENERATOR	06/04/2014	Nitrogen Oxides (NOx)	3600	BHP	4.46	G/BHP-H	3-HR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0180	MIDWEST FERTILIZER CORPORATION	DIESEL FIRED EMERGENCY GENERATOR	06/04/2014	Nitrogen Oxides (NOx)	3600	BHP	4.46	G/B-HP-H	3-HR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0185	MAG PELLET LLC	DIESEL FIRE PUMP	04/24/2014	Nitrogen Oxides (NOx)	300	HP	3	G/HP-H		

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Nitrogen Oxides (NO_x)	3600	HP EACH	4.42	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Nitrogen Oxides (NO_x)	2800	HP	6.4	G/KWH	TIER II NOX + NMHC LIMIT	Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Nitrogen Oxides (NO_x)	750	HP	4	G/KWH	COMBINED NOX + NMHC LIMIT	Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Nitrogen Oxides (NO_x)	3600	HP	4.42	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Nitrogen Oxides (NO_x)	500	HP	2.83	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Nitrogen Oxides (NO_x)	3000	Horsepower	4.8	G/HP-HR		certified engine
IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Nitrogen Oxides (NO_x)	420	brake hp	4	G/KW-HR		
IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Nitrogen Oxides (NO_x)	2012	hp	4.8	G/HP-HR		
IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (400 kW)	01/11/2024	Nitrogen Oxides (NO_x)	619	HP	2.29	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (1000 kW)	01/11/2024	Nitrogen Oxides (NO_x)	1000	kW	3.81	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (2000 kW)	01/11/2024	Nitrogen Oxides (NO_x)	2000	kW	3.81	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
IN-0371	WABASH VALLEY RESOURCES, LLC	Ammonia Plant Emergency Generator	01/11/2024	Nitrogen Oxides (NO_x)	500	kW	4.8	G/HP-HR		Good Combustion Practices and meeting NSPS Subpart IIII requirements.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Nitrogen Oxides (NO_x)	920	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	2922	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	2922	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	700	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	2922	HP	4.77	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Nitrogen Oxides (NO_x)	2922	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Nitrogen Oxides (NO_x)	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Nitrogen Oxides (NO_x)	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Nitrogen Oxides (NO_x)	700	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	05/23/2014	Nitrogen Oxides (NOx)	2682	HP	27.37	LB/HR	HOURLY MAXIMUM	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturers instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Nitrogen Oxides (NO_x)	1341	HP	14.16	LB/HR	HOURLY MAXIMUM	Good equipment design, proper combustion techniques, use of low sulfur fuel, and compliance with 40 CFR 60 Subpart IIII

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	05/23/2014	Nitrogen Oxides (NOx)	2682	HP	27.37	LB/HR	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturers instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Nitrogen Oxides (NO_x)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Nitrogen Oxides (NO_x)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Nitrogen Oxides (NO_x)	2922	hp (each)	6.4	G/KW-HR		Complying with 40 CFR 60 Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Nitrogen Oxides (NO_x)	650	horsepower	6.6	LB/HR		Compliance with NSPS Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Nitrogen Oxides (NO_x)	1474	horsepower	19.23	LB/HR		Compliance with NSPS Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Nitrogen Oxides (NO_x)	2584	HP	27.34	LB/H	HOURLY MAXIMUM	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).
LA-0315	G2G PLANT	Emergency Diesel Generator 1	05/23/2014	Nitrogen Oxides (NOx)	5364	HP	52.58	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0315	G2G PLANT	Emergency Diesel Generator 2	05/23/2014	Nitrogen Oxides (NOx)	5364	HP	52.58	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0315	G2G PLANT	Fire Pump Diesel Engine 1	05/23/2014	Nitrogen Oxides (NOx)	751	HP	4.6	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0315	G2G PLANT	Fire Pump Diesel Engine 2	05/23/2014	Nitrogen Oxides (NOx)	751	HP	4.6	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Nitrogen Oxides (NO_x)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Nitrogen Oxides (NO_x)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Nitrogen Oxides (NO_x)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0318	FLOPAM FACILITY	Diesel Engines	01/07/2016	Nitrogen Oxides (NO_x)	0		0			Complying with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Nitrogen Oxides (NO_x)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Nitrogen Oxides (NO_x)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0324	COMMONWEALTH LNG FACILITY	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Nitrogen Oxides (NO_x)	0		5.53	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0324	COMMONWEALTH LNG FACILITY	Generator Engines (EQT0016)	03/28/2023	Nitrogen Oxides (NO_x)	4290	kw	8.46	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Nitrogen Oxides (NO_x)	5364	HP	5.6	G/KW-H		Good Combustion and Operating Practices
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Nitrogen Oxides (NO_x)	634	kW	3.1	G/HP-H		Good Combustion and Operating Practices.
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Nitrogen Oxides (NO_x)	550	hp	0			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.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Nitrogen Oxides (NO_x)	550	hp	0			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.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator A	05/04/2021	Nitrogen Oxides (NO_x)	1389	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0379	SHINTECH PLAQUEMINES PLANT 1	C/A Emergency Generator B	05/04/2021	Nitrogen Oxides (NO_x)	1800	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Nitrogen Oxides (NO_x)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Nitrogen Oxides (NO_x)	2937	hp	4.8	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.
LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Nitrogen Oxides (NO_x)	670.5	horsepower	4.24	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Nitrogen Oxides (NO_x)	670.5	horsepower	4.24	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Nitrogen Oxides (NO_x)	3634	horsepower	38.24	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Nitrogen Oxides (NO_x)	2923	horsepower	28.48	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Nitrogen Oxides (NO_x)	2923	horsepower	28.48	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MI-0418	WARREN TECHNICAL CENTER	Four (4) emergency engines in FG-BACKUPGENS	01/14/2015	Nitrogen Oxides (NO_x)	2710	KW	7.13	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.
MI-0418	WARREN TECHNICAL CENTER	FG-BACKUPGENS (Nine (9) DRUPS Emergency Engines)	01/14/2015	Nitrogen Oxides (NO_x)	3490	KW	8	G/KW-H	TEST PROTOCOL (LIMIT IS PER ENGINE)	No add-on controls, but injection timing retardation (ITR) is good design. Engines are tuned for low-NOx operation versus low CO operation.
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Nitrogen Oxides (NO_x)	500	H/YR	3.53	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, limited operating hours.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Nitrogen Oxides (NO_x)	500	H/YR	22.6	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, limited operating hours.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Nitrogen Oxides (NO_x)	22.68	MMBTU/H	6.4	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices and meeting NSPS IIII requirements.
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Nitrogen Oxides (NO_x)	500	H/YR	3.53	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Limited operating hours.

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Nitrogen Oxides (NO_x)	500	H/YR	21.2	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, limited operating hours.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Nitrogen Oxides (NO_x)	500	H/YR	4.4	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, limited operating hours
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good combustion practices and meeting NSPS IIII requirements.
MI-0434	FLAT ROCK ASSEMBLY PLANT	EUENGINE01 through EUENGINE08	03/22/2018	Nitrogen Oxides (NO_x)	3633	BHP	6.4	G/KW-H	HOURLY; EACH ENGINE; NMHC+NOX	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Nitrogen Oxides (NO_x)	2	MW	6.4	G/KW-H	HOURLY	State of the art combustion design.
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Nitrogen Oxides (NO_x)	1500	HP	6.4	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Nitrogen Oxides (NO_x)	6000	HP	6.4	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Nitrogen Oxides (NO_x)	1100	KW	5.3	G/HP-H	HOURLY; EACH ENGINE	
MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Nitrogen Oxides (NO_x)	22.68	MMBTU/H	6.4	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Nitrogen Oxides (NO_x)	500	h/yr	3.53	LB/H	HOURLY	Certified Engines, Limited Operating Hours
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Nitrogen Oxides (NO_x)	500	h/yr	21.2	LB/H	HOURLY	Certified engines, limited operating hours
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Nitrogen Oxides (NO_x)	500	h/yr	4.4	LB/H	HOURLY	Certified Engines, Limited Operating Hours
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Nitrogen Oxides (NO_x)	1341	HP	6.4	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Nitrogen Oxides (NO_x)	4474.2	KW	6.4	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 1	11/21/2022	Nitrogen Oxides (NO_x)	510	hp	2.38	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Nitrogen Oxides (NO_x)	1100	KW	29.01	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Nitrogen Oxides (NO_x)	2346	HP	21.6	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Nitrogen Oxides (NO_x)	2947	HP	27.18	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Nitrogen Oxides (NO_x)	5000	HP	5.5	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Nitrogen Oxides (NO_x)	1529	HP	16.07	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Nitrogen Oxides (NO_x)	1529	HP	16.1	LB/H		State-of-the-art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Nitrogen Oxides (NO_x)	2206	HP	23.21	LB/H	NMHC+NOX. SEE NOTES.	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.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Nitrogen Oxides (NO_x)	2206	HP	24.71	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Nitrogen Oxides (NO_x)	700	HP	4.97	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Nitrogen Oxides (NO_x)	2682	HP	28.2	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Nitrogen Oxides (NO_x)	1860	HP	19.68	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Nitrogen Oxides (NO_x)	3353	HP	37.41	LB/H	SEE NOTES.	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

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Nitrogen Oxides (NO_x)	1341	HP	14.96	LB/H	SEE NOTES.	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
OH-0379	PETMIN USA INCORPORATED	Emergency Generators (P005 and P006)	02/06/2019	Nitrogen Oxides (NO_x)	3131	HP	3.45	LB/H		Tier IV engine Tier IV NSPS standards certified by engine manufacturer.
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Nitrogen Oxides (NO_x)	3131	HP	0			Tier IV NSPS standards certified by engine manufacturer.
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Nitrogen Oxides (NO_x)	5051	HP	6.4	G/KW-H	6.4 GRAMS NOX + NMHC/KW-HR	Certified to meet Tier 2 standards and good combustion practices
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	Emergency Diesel Generator	04/10/2014	Nitrogen Oxides (NOx)	0		2.85	G/B-HP-H		
SD-0005	DEER CREEK STATION	Emergency Generator	06/29/2010	Nitrogen Oxides (NO_x)	2000	Kilowatts	0			
SD-0005	DEER CREEK STATION	Fire Water Pump	06/29/2010	Nitrogen Oxides (NO_x)	577	horsepower	0			
TX-0671	PROJECT JUMBO	Engines	12/01/2014	Nitrogen Oxides (NO_x)	0		5.43	G/KW-H		Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Nitrogen Oxides (NO_x)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Nitrogen Oxides (NO_x)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
TX-0879	MOTIVA PORT ARTHUR TERMINAL	Emergency Firewater Engine	02/19/2020	Nitrogen Oxides (NO_x)	0		0			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.
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Nitrogen Oxides (NO_x)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	EMERGENCY GENERATOR	09/09/2020	Nitrogen Oxides (NO_x)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101

Table D-4.1 Summary of NO_x BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Nitrogen Oxides (NO_x)	0		0			limited to 100 hours per year of non-emergency operation
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Nitrogen Oxides (NO_x)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Nitrogen Oxides (NO_x)	500	H/YR	4.8	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Nitrogen Oxides (NO_x)	500	H/YR	4.8	G/HP-H		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.
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Nitrogen Oxides (NO_x)	0		5.36	G/KWH		The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Nitrogen Oxides (NO_x)	0		5.36	G/KWH		Good Combustion Practices, The Use of an Engine Turbocharger and Aftercooler.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Nitrogen Oxides (NO_x)	1490	HP	4.8	G/HP-H		Operation limited to 500 hours/year and operate and maintain according to the manufacturer's recommendations.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Nitrogen Oxides (NO_x)	2015.7	HP	0			
WV-0027	INWOOD	Emergency Generator - ESDG14	09/15/2017	Nitrogen Oxides (NO_x)	900	bhp	4.77	G/HP-HR		Engine Design
WV-0033	MAIDSVILLE	Emergency Generator	01/05/2022	Nitrogen Oxides (NO_x)	2100	hp	24.6	LB/HR		Combustion Control (retarded timing and/or lean burn)
WV-0033	MAIDSVILLE	Fire Water Pump	01/05/2022	Nitrogen Oxides (NO_x)	240	bhp	1.59	LB/HR		Combustion control (retarded timing and/or lean burn)

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Carbon Monoxide	2695	hp	2.6	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Carbon Monoxide	610	hp	2.6	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Carbon Monoxide	891	hp	2.6	GRAMS/HP-H		
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Carbon Monoxide	143.5	MMBtu/hr	0.18	G/KW-HR (ULSD)	3-HOUR AVERAGE	Oxidation Catalyst and Maintain Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Carbon Monoxide	1500	kWe	4.38	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Carbon Monoxide	186.6	gph	3.3	G/HP-HR	3-HOUR AVERAGE	Oxidation Catalyst, Good Combustion Practices, and 500 hour limit per year.
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Carbon Monoxide	27.9	Gal/hr	3.3	G/HP-HR		Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
AL-0301	NUCOR STEEL TUSCALOOSA, INC.	DIESEL FIRED EMERGENCY GENERATOR	07/22/2014	Carbon Monoxide	800	HP	0.0055	LB/HP-H		
AL-0328	PLANT BARRY	Diesel Emergency Engines	11/09/2020	Carbon Monoxide	0		2.6	G/BHP-HR		
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Carbon Monoxide	0		3.5	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Carbon Monoxide	0		3.5	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Carbon Monoxide	3634	Horsepower	3.5	G/KW-HR		
AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Carbon Monoxide	0		0.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0346	LAUDERDALE PLANT	Four 3100 kW black start emergency generators	04/22/2014	Carbon Monoxide	2.32	MMBtu/hr (HHV) per engine	3.5	GRAMS PER KW-HR		Good combustion practice
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	Emergency Diesel Engine	09/16/2014	Carbon Monoxide	3300	hp	0			Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0347	ANADARKO PETROLEUM CORPORATION - EGOM	Main Propulsion Generator Diesel Engines	09/16/2014	Carbon Monoxide	9910	hp	0.8	G/KW-H	ROLLING 24 HOUR AVERAGE	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Three 3300-kW ULSD emergency generators	03/09/2016	Carbon Monoxide	0		3.5	G / KW-HR		Use of clean engine
FL-0363	DANIA BEACH ENERGY CENTER	Two 3300 kW emergency generators	12/04/2017	Carbon Monoxide	0		3.5	GRAMS PER KWH		Certified engine
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	07/27/2018	Carbon Monoxide	14.82	MMBtu/hour	3.5	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	1,500 kW Emergency Diesel Generator	06/07/2021	Carbon Monoxide	14.82	MMBtu/hour	3.5	G/KW-HOUR		
IL-0114	CRONUS CHEMICALS, LLC	Emergency Generator	09/05/2014	Carbon Monoxide	3755	HP	3.5	G/KW-H		Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.
IL-0129	CPV THREE RIVERS ENERGY CENTER	Emergency Engines	07/30/2018	Carbon Monoxide	0		0			
IL-0130	JACKSON ENERGY CENTER	Emergency Engine	12/31/2018	Carbon Monoxide	1500	kW	3.5	G/KW-HR		
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Carbon Monoxide	1250	kW	3.5	GRAMS	KILOWATT-HOUR	
IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Carbon Monoxide	3985	hp	3.5	G/KW-HR	3-HR AVG	
IN-0173	MIDWEST FERTILIZER CORPORATION	DIESEL FIRED EMERGENCY GENERATOR	06/04/2014	Carbon Monoxide	3600	BHP	2.61	G/BHP-H	3-HR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0180	MIDWEST FERTILIZER CORPORATION	DIESEL FIRED EMERGENCY GENERATOR	06/04/2014	Carbon Monoxide	3600	BHP	2.61	G/B-HP-H	3-HR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Carbon Monoxide	3600	HP EACH	2.61	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Carbon Monoxide	2800	HP	3.5	G/KWH		Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Carbon Monoxide	750	HP	3.5	G/KWH		Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Carbon Monoxide	3600	HP	2.61	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Carbon Monoxide	500	HP	2.6	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Carbon Monoxide	3000	Horsepower	2.61	G/HP-HR		oxidation catalyst and certified engine
IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Carbon Monoxide	420	brake hp	3.5	G/KW-HR		

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Carbon Monoxide	2012	hp	2.6	G/HP-HR		
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Carbon Monoxide	53.6	gal/hr	2.6	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT	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 practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Divisions inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Carbon Monoxide	920	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Carbon Monoxide	2922	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Carbon Monoxide	2922	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Carbon Monoxide	700	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Carbon Monoxide	2922	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Carbon Monoxide	2922	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Carbon Monoxide	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Carbon Monoxide	2937	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Carbon Monoxide	700	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0288	LAKE CHARLES CHEMICAL COMPLEX	Emergency Diesel Generators (EQT 629, 639, 838, 966, & 1264)	05/23/2014	Carbon Monoxide	2682	HP	15.43	LB/HR	HOURLY MAXIMUM	Comply with 40 CFR 60 Subpart IIII; operate the engine in accordance with the engine manufacturers instructions and/or written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0296	LAKE CHARLES CHEMICAL COMPLEX LDPE UNIT	Emergency Diesel Generators (EQTs 622, 671, 773, 850, 994, 995, 996, 1033, 1077, 1105, & 1202)	05/23/2014	Carbon Monoxide	2682	HP	15.43	LB/HR	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII; operating the engine in accordance with the engine manufacturers instructions and/or written procedures (consistent with safe operation) designed to maximize combustion efficiency and minimize fuel usage.
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Carbon Monoxide	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Carbon Monoxide	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Carbon Monoxide	2922	hp (each)	0			Complying with 40 CFR 60 Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Carbon Monoxide	650	horsepower	0.9	LB/HR		Compliance with NSPS Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Carbon Monoxide	1474	horsepower	0.51	LB/HR		Compliance with NSPS Subpart IIII

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Carbon Monoxide	2584	HP	14.81	LB/H	HOURLY MAXIMUM	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).
LA-0315	G2G PLANT	Emergency Diesel Generator 1	05/23/2014	Carbon Monoxide	5364	HP	30.86	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0315	G2G PLANT	Emergency Diesel Generator 2	05/23/2014	Carbon Monoxide	5364	HP	30.86	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0315	G2G PLANT	Fire Pump Diesel Engine 1	05/23/2014	Carbon Monoxide	751	HP	4.32	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0315	G2G PLANT	Fire Pump Diesel Engine 2	05/23/2014	Carbon Monoxide	751	HP	4.32	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Carbon Monoxide	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Carbon Monoxide	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Carbon Monoxide	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0318	FLOPAM FACILITY	Diesel Engines	01/07/2016	Carbon Monoxide	0		0			Complying with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Carbon Monoxide	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Carbon Monoxide	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0324	COMMONWEALTH LNG FACILITY	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Carbon Monoxide	0		0.55	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0324	COMMONWEALTH LNG FACILITY	Generator Engines (EQT0016)	03/28/2023	Carbon Monoxide	4290	kw	1.21	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Carbon Monoxide	5364	HP	3.5	G/KW-H		Good Combustion and Operating Practices.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Carbon Monoxide	634	kW	3.7	G/HP-H		Good Combustion and Operating Practices.

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Carbon Monoxide	550	hp	0			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.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Carbon Monoxide	550	hp	0			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.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator A	05/04/2021	Carbon Monoxide	1389	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	C/A Emergency Generator B	05/04/2021	Carbon Monoxide	1800	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Carbon Monoxide	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Carbon Monoxide	575	hp	3.97	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Carbon Monoxide	2937	hp	2.6	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Carbon Monoxide	670.5	horsepower	3.81	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Carbon Monoxide	670.5	horsepower	3.81	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Carbon Monoxide	3634	horsepower	20.91	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Carbon Monoxide	2923	horsepower	2.9	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Carbon Monoxide	2923	horsepower	2.9	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MD-0042	WILDCAT POINT GENERATION FACILITY	EMERGENCY GENERATOR 1	04/08/2014	Carbon Monoxide	2250	KW	2.6	G/HP-H		USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES AND HOURS OF OPERATION LIMITED TO 100 HOURS PER YEAR

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MD-0044	COVE POINT LNG TERMINAL	EMERGENCY GENERATOR	06/09/2014	Carbon Monoxide	1550	HP	2.6	G/HP-H		GOOD COMBUSTION PRACTICES AND DESIGNED TO MEET EMISSION LIMIT
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good design and combustion practices.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good design and combustion practices.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Carbon Monoxide	22.68	MMBTU/H	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY AVG TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Carbon Monoxide	500	H/YR	3.5	G/KW-H	TEST PROTOCOL SHALL SPECIFY	Good design and combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good combustion practices and meeting NSPS IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Carbon Monoxide	2	MW	3.5	G/KW-H	HOURLY	State of the art combustion design.
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Carbon Monoxide	1500	HP	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Carbon Monoxide	6000	HP	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Carbon Monoxide	1100	KW	0.15	G/HP-H	HOURLY; EACH ENGINE	
MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Carbon Monoxide	22.68	MMBTU/H	3.5	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Carbon Monoxide	4474.2	KW	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Carbon Monoxide	500	h/yr	3.5	G/KW-H	HOURLY	Good Design and Combustion Practices
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Carbon Monoxide	500	h/yr	3.5	G/KW-H	HOURLY	Good design and combustion practices
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Carbon Monoxide	500	h/yr	3.5	G/KW-H	HOURLY	Good Design and Combustion Practices
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good combustion practices and meeting NSPS IIII requirements.
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Carbon Monoxide	1341	HP	3.5	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Carbon Monoxide	4474.2	KW	3.5	G/KW-H	HOURLY	Good combustion practices and will be NSPS compliant.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Diesel Fired Emergency Generator	03/10/2016	Carbon Monoxide	44	H/YR	3.5	LB/H		use of ultra low sulfur diesel oil a clean burning fuel
NY-0103	CRICKET VALLEY ENERGY CENTER	Black start generator	02/03/2016	Carbon Monoxide	3000	KW	2.6	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Carbon Monoxide	1100	KW	8.49	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Carbon Monoxide	2346	HP	13.5	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Carbon Monoxide	2947	HP	16.96	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Carbon Monoxide	5000	HP	28.8	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Carbon Monoxide	1529	HP	8.8	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Carbon Monoxide	1529	HP	8.8	LB/H		State-of-the-art combustion design

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Carbon Monoxide	2206	HP	12.69	LB/H		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.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Carbon Monoxide	2206	HP	12.64	LB/H		Good combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Carbon Monoxide	700	HP	4.01	LB/H		Good combustion design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Carbon Monoxide	2682	HP	15.4	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Carbon Monoxide	3353	HP	19.25	LB/H		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
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Carbon Monoxide	1341	HP	7.7	LB/H		certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII, shall employ good combustion practices per the manufacturers operating manual
OH-0383	PETMIN USA INCORPORATED	Emergency Generators (P005 and P006)	07/17/2020	Carbon Monoxide	3131	HP	0			Tier IV engine Good combustion practices
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Carbon Monoxide	3131	HP	0			Tier IV NSPS standards certified by engine manufacturer.
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Carbon Monoxide	5051	HP	3.5	G/KW-H		Certified to meet Tier 2 standards and good combustion practices
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Carbon Monoxide	0		0.6	GM/HP-HR		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Emergency Generator Engines	09/02/2016	Carbon Monoxide	0		2.61	G/BHP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Carbon Monoxide	0		0.26	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Carbon Monoxide	0		1	G/HP-HR		
PR-0009	ENERGY ANSWERS ARECIBO PUERTO RICO RENEWABLE ENERGY PROJECT	Emergency Diesel Generator	04/10/2014	Carbon Monoxide	0		2.6	G/BHP-H		
SD-0005	DEER CREEK STATION	Emergency Generator	06/29/2010	Carbon Monoxide	2000	Kilowatts	0			
SD-0005	DEER CREEK STATION	Fire Water Pump	06/29/2010	Carbon Monoxide	577	horsepower	0			

Table D-4.2 Summary of CO BACT Determinations for Large Engines

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TX-0799	BEAUMONT TERMINAL	Fire pump engines	06/08/2016	Carbon Monoxide	0		0.0055	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0872	CONDENSATE SPLITTER FACILITY	Emergency Generators	10/31/2019	Carbon Monoxide	0		0.6	G/KW HR		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.
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Carbon Monoxide	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Carbon Monoxide	0		0			Tier 3 exhaust emission standards specified in 40 CFR Â§ 89.112, limited to 100 hours per year of non-emergency operation
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Carbon Monoxide	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	EMERGENCY GENERATOR	09/09/2020	Carbon Monoxide	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Carbon Monoxide	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	DIESEL GENERATOR	03/17/2021	Carbon Monoxide	0		2.61	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Carbon Monoxide	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	EMERGENCY GENERATOR	03/13/2023	Carbon Monoxide	18.7	MMBTU/HR	0.006	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Carbon Monoxide	500	H/YR	2.6	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Carbon Monoxide	500	H/YR	2.6	G/HP-H		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.
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Carbon Monoxide	0		0.6	G/KWH		Good Combustion Practices

Table D-4.2 Summary of CO BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Carbon Monoxide	0		0.6	G/KWH		Good Combustion Practices
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Carbon Monoxide	1490	HP	2.6	G/HP-H		Operation limited to 500 hours/year, and operate and maintain generator according to the manufacturer's recommendations.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Carbon Monoxide	2015.7	HP	0			
WV-0033	MAIDSVILLE	Emergency Generator	01/05/2022	Carbon Monoxide	2100	hp	1.94	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine
WV-0033	MAIDSVILLE	Fire Water Pump	01/05/2022	Carbon Monoxide	240	bhp	1.38	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Volatile Organic Compounds (VOC)	2695	hp	0.0007	LB/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Volatile Organic Compounds (VOC)	610	hp	0.0007	LB/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Volatile Organic Compounds (VOC)	891	hp	0.0007	LB/HP-H		
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Volatile Organic Compounds (VOC)	143.5	MMBtu/hr	0.21	G/KW-HR (ULSD)	3-HOUR AVERAGE	Oxidation Catalyst and Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Volatile Organic Compounds (VOC)	186.6	gph	0.18	G/HP-HR	3-HOUR AVERAGE	Oxidation Catalyst, Good combustion practices, and limit operation to 500 hours per year.
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Volatile Organic Compounds (VOC)	27.9	Gal/hr	0.19	G/HP-HR		Oxidation Catalyst; Limited Operation; 40 CFR 60 Subpart IIII
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Volatile Organic Compounds (VOC)	0		1.9	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Volatile Organic Compounds (VOC)	0		1.55	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Volatile Organic Compounds (VOC)	3634	Horsepower	0.8	G/KW-HR		
IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Volatile Organic Compounds (VOC)	3985	hp	6.4	G/KW-HR	3-HR AVG	
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Volatile Organic Compounds (VOC)	3600	HP EACH	0.35	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Volatile Organic Compounds (VOC)	2800	HP	6.4	G/KWH	TIER II NOX + NMHC LIMIT	Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Volatile Organic Compounds (VOC)	750	HP	4	G/KWH	COMBINED NOX + NMHC LIMIT	Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Volatile Organic Compounds (VOC)	3600	HP	0.35	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Volatile Organic Compounds (VOC)	500	HP	0.141	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Volatile Organic Compounds (VOC)	3000	Horsepower	0.32	G/HP-HR		certified engine

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Volatile Organic Compounds (VOC)	53.6	gal/hr	4.77	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	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 practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Volatile Organic Compounds (VOC)	920	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	700	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
LA-0276	BATON ROUGE JUNCTION FACILITY	Fire Pump Engines (2 units)	12/15/2016	Volatile Organic Compounds (VOC)	700	hp	0			Comply with standards of NSPS Subpart IIII
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Volatile Organic Compounds (VOC)	1341	HP	0.83	LB/HR	HOURLY MAXIMUM	Good combustion practices consistent with the manufacturer's recommendations to maximize fuel efficiency and minimize emissions
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Volatile Organic Compounds (VOC)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Volatile Organic Compounds (VOC)	2922	hp (each)	0			Complying with 40 CFR 60 Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Volatile Organic Compounds (VOC)	650	horsepower	0.13	LB/HR		Compliance with NNSPS Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Volatile Organic Compounds (VOC)	1474	horsepower	0.04	LB/HR		Compliance with NSPS Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Volatile Organic Compounds (VOC)	2584	HP	27.34	LB/H	HOURLY MAXIMUM	Good combustion practices
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Volatile Organic Compounds (VOC)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0324	COMMONWEALTH LNG FACILITY	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Volatile Organic Compounds (VOC)	0		0.4	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0324	COMMONWEALTH LNG FACILITY	Generator Engines (EQT0016)	03/28/2023	Volatile Organic Compounds (VOC)	4290	kw	0.322	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Volatile Organic Compounds (VOC)	5364	HP	0.79	G/KW-H		Good combustion and operating practices.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Volatile Organic Compounds (VOC)	634	kW	0.44	G/HP-H		Good combustion and operating practices.
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Volatile Organic Compounds (VOC)	550	hp	0			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.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Volatile Organic Compounds (VOC)	550	hp	0			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.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Volatile Organic Compounds (VOC)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Volatile Organic Compounds (VOC)	575	hp	0.32	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0390	DERIDDER SAWMILL	GEN-1 - Emergency Generator No. 1	05/10/2022	Volatile Organic Compounds (VOC)	750	horsepower	1.98	LB/HR		Good combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitation for VOC.
LA-0390	DERIDDER SAWMILL	GEN-2 - Emergency Generator No. 2	05/10/2022	Volatile Organic Compounds (VOC)	750	horsepower	1.98	LB/HR		Good combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitation for VOC
LA-0390	DERIDDER SAWMILL	GEN-3 - Emergency Generator No. 2	05/10/2022	Volatile Organic Compounds (VOC)	750	horsepower	1.98	LB/HR		Good Combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitations for VOC
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Volatile Organic Compounds (VOC)	2937	hp	4.8	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII standards, good combustion practices, and the use of ultra-low sulfur diesel fuel.
LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Volatile Organic Compounds (VOC)	670.5	horsepower	0.11	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Volatile Organic Compounds (VOC)	670.5	horsepower	0.11	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Volatile Organic Compounds (VOC)	3634	horsepower	2.29	LB/HR		Compliance with 40 CFR 60 Subpart IIII

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Volatile Organic Compounds (VOC)	2923	horsepower	2.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Volatile Organic Compounds (VOC)	2923	horsepower	2.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Volatile Organic Compounds (VOC)	22.68	MMBTU/H	1.87	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Volatile Organic Compounds (VOC)	2	MW	1.89	LB/H	HOURLY	State of the art combustion design.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Volatile Organic Compounds (VOC)	1100	KW	0.86	LB/H	HOURLY; EACH ENGINE	
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Volatile Organic Compounds (VOC)	1341	HP	0.86	LB/H	HOURLY	Good combustion practices.
NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 1	11/21/2022	Volatile Organic Compounds (VOC)	510	hp	0.62	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Volatile Organic Compounds (VOC)	2346	HP	3.1	LB/H		
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Volatile Organic Compounds (VOC)	2947	HP	3.84	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Volatile Organic Compounds (VOC)	5000	HP	1.6	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Volatile Organic Compounds (VOC)	1529	HP	2	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Volatile Organic Compounds (VOC)	1529	HP	2	LB/H		State-of-the-art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Volatile Organic Compounds (VOC)	2206	HP	23.21	LB/H	NMHC+NOX. SEE NOTES.	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.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Volatile Organic Compounds (VOC)	2206	HP	24.71	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Volatile Organic Compounds (VOC)	700	HP	4.97	LB/H	NMHC+NOX. SEE NOTES.	Good combustion design
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Volatile Organic Compounds (VOC)	1860	HP	19.68	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Volatile Organic Compounds (VOC)	3353	HP	37.41	LB/H	SEE NOTES.	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
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Volatile Organic Compounds (VOC)	1341	HP	14.96	LB/H	SEE NOTES.	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
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Volatile Organic Compounds (VOC)	5051	HP	0.4	G/KW-H		Certified to meet Tier 2 standards and good combustion practices
OK-0175	WILDHORSE TERMINAL	Emergency Use Engines > 500 HP	06/29/2017	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good combustion practices. Certified to meet EPA Tier 3 engine standards. Shall be limited to operate at no more than 500 hr/yr.
OK-0181	WILDHORSE TERMINAL	EMERGENCY USE ENGINES > 500 HP	09/11/2019	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good combustion practices. Certified to meet EPA Tier 3 engine standards. Each engine shall be limited to operate not more than 500 hours per year.
SC-0193	MERCEDES BENZ VANS, LLC	Emergency Generators and Fire Pump	04/15/2016	Volatile Organic Compounds (VOC)	1500	hp	100	HR/YR	12 MONTH ROLLING SUM	Must meet the standards of 40 CFR 60, Subpart IIII
TX-0799	BEAUMONT TERMINAL	Fire pump engines	06/08/2016	Volatile Organic Compounds (VOC)	0		0.0007	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0872	CONDENSATE SPLITTER FACILITY	Emergency Generators	10/31/2019	Volatile Organic Compounds (VOC)	0		0.12	G/KW HR		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.
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Volatile Organic Compounds (VOC)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Volatile Organic Compounds (VOC)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0879	MOTIVA PORT ARTHUR TERMINAL	Emergency Firewater Engine	02/19/2020	Volatile Organic Compounds (VOC)	0		0.1	G/HP HR		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.
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Volatile Organic Compounds (VOC)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	EMERGENCY GENERATOR	09/09/2020	Volatile Organic Compounds (VOC)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Volatile Organic Compounds (VOC)	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	DIESEL GENERATOR	03/17/2021	Volatile Organic Compounds (VOC)	0		0.5	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Volatile Organic Compounds (VOC)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	EMERGENCY GENERATOR	03/13/2023	Volatile Organic Compounds (VOC)	18.7	MMBTU/HR	0.001	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
VA-0327	PERDUE GRAIN AND OILSEED, LLC	Emergency Generator	07/12/2017	Volatile Organic Compounds (VOC)	0		0.49	LB/HR		
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Volatile Organic Compounds (VOC)	0		0.56	G/KWH		Good Combustion Practices
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Volatile Organic Compounds (VOC)	0		0.56	G/KWH		Good Combustion Practices
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Diesel-Fired Emergency Fire Pump (P36)	12/10/2019	Volatile Organic Compounds (VOC)	510	HP	200	H/Y	IN ANY CONSECUTIVE 12-MONTH PERIOD	
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Volatile Organic Compounds (VOC)	1490	HP	0.32	G/HP-H		Operation limited to 500 hours/year and operate and maintain generator according to the manufacturerâ€™s recommendations
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Volatile Organic Compounds (VOC)	2015.7	HP	1.24	LB/H		
WV-0033	MAIDSVILLE	Emergency Generator	01/05/2022	Volatile Organic Compounds (VOC)	2100	hp	0.46	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine

Table D-4.3 Summary of VOC BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WV-0033	MAIDSVILLE	Fire Water Pump	01/05/2022	Volatile Organic Compounds (VOC)	240	bhp	1.59	LB/HR		Good Combustion Practices w/ OxCat. Applicant did not justify why an oxcat is infeasible for an emergency engine

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Emergency Camp Generators	01/23/2015	Particulate matter, filterable (FPM10)	2695	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Emergency Camp Generators	01/23/2015	Particulate matter, filterable (FPM2.5)	2695	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Fine Water Pumps	01/23/2015	Particulate matter, filterable (FPM10)	610	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Fine Water Pumps	01/23/2015	Particulate matter, filterable (FPM2.5)	610	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Bulk Tank Generator Engines	01/23/2015	Particulate matter, filterable (FPM10)	891	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	17.11	Bulk Tank Generator Engines	01/23/2015	Particulate matter, filterable (FPM2.5)	891	hp	0.15	GRAMS/HP-H		
AK-0084	DONLIN GOLD PROJECT	17.11	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, filterable (FPM)	143.5	MMBtu/hr	0.15	G/KW-HR (ULSD)		Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	17.11	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, filterable (FPM10)	143.5	MMBtu/hr	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	17.11	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, filterable (FPM2.5)	143.5	MMBtu/hr	0.15	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AL-0328	PLANT BARRY	17.11	Diesel Emergency Engines	11/09/2020	Particulate matter, filterable (FPM)	0		0.15	G/BHP-HR		
AR-0161	SUN BIO MATERIAL COMPANY	17.11	Emergency Engines	09/23/2019	Particulate matter, filterable (FPM)	0		0.02	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0163	BIG RIVER STEEL LLC	17.11	Emergency Engines	06/09/2019	Particulate matter, filterable (FPM)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	17.11	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Particulate matter, filterable (FPM)	3634	Horsepower	0.2	G/KW-HR		
FL-0363	DANIA BEACH ENERGY CENTER	17.11	Two 3300 kW emergency generators	12/04/2017	Particulate matter, filterable (FPM)	0		0.2	GRAMS PER		Clean fuel
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	17.11	1,500 kW Emergency Diesel Generator	07/27/2018	Particulate matter, filterable (FPM)	14.82	MMBtu/hour	0.2	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
KS-0040	JOHNS MANVILLE AT MCPHERSON	17.11	Emergency Diesel Engines	12/03/2019	Particulate matter, filterable (FPM)	0		0.2	GR/KWH		Emergency Diesel Engine and Fire Pump Subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.
KS-0040	JOHNS MANVILLE AT MCPHERSON	17.11	Emergency Diesel Engines	12/03/2019	Particulate matter, filterable (FPM10)	0		0.2	G/KWH		One diesel engine and fire pump subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0040	JOHNS MANVILLE AT MCPHERSON	17.11	Emergency Diesel Engines	12/03/2019	Particulate matter, filterable (FPM2.5)	0		0.2	GR/KWH		One diesel fuel emergency engine and one fire pump subject to NSPS Subpart IIII - Combustion Control and Limited Operating Hours.
KY-0109	FRITZ WINTER NORTH AMERICA, LP	17.11	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Particulate matter, filterable (FPM)	53.6	gal/hr	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	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 practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Particulate matter, filterable (FPM)	920	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-02 - North Water System Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-03 - South Water System Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	700	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	17.11	EP 10-01 - Caster Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Particulate matter, filterable (FPM)	2922	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Particulate matter, filterable (FPM)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	Caster B Emergency Generator (EP 08-07)	04/19/2021	Particulate matter, filterable (FPM)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	17.11	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Particulate matter, filterable (FPM)	700	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0313	ST. CHARLES POWER STATION	17.11	SCPS Emergency Diesel Generator 1	08/31/2016	Particulate matter, filterable (FPM10)	2584	HP	0.86	LB/H	HOURLY MAXIMUM	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).
LA-0313	ST. CHARLES POWER STATION	17.11	SCPS Emergency Diesel Generator 1	08/31/2016	Particulate matter, filterable (FPM2.5)	2584	HP	0.86	LB/H	HOURLY MAXIMUM	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).
LA-0324	COMMONWEALTH LNG FACILITY	17.11	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Particulate matter, filterable (FPM10)	0		0.125	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0324	COMMONWEALTH LNG FACILITY	17.11	Firewater Pump Engine (EQT0017 - EQT0020)	03/28/2023	Particulate matter, filterable (FPM2.5)	0		0.125	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0324	COMMONWEALTH LNG FACILITY	17.11	Generator Engines (EQT0016)	03/28/2023	Particulate matter, filterable (FPM2.5)	4290	kw	0.067	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0324	COMMONWEALTH LNG FACILITY	17.11	Generator Engines (EQT0016)	03/28/2023	Particulate matter, filterable (FPM10)	4290	kw	0.067	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII and operating engines per manufacturers' instructions and written procedures designed to maximize combustion efficiency and minimize fuel usage.
LA-0364	FG LA COMPLEX	17.11	Emergency Generator Diesel Engines	01/06/2020	Particulate matter, filterable (FPM2.5)	550	hp	0			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.
MI-0421	GRAYLING PARTICLEBOARD	17.11	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Particulate matter, filterable (FPM)	500	H/YR	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0421	GRAYLING PARTICLEBOARD	17.11	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Particulate matter, filterable (FPM)	500	H/YR	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0423	INDECK NILES, LLC	17.11	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Particulate matter, filterable (FPM)	22.68	MMBTU/H	0.2	G/KW-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0425	GRAYLING PARTICLEBOARD	17.11	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Particulate matter, filterable (FPM)	500	H/YR	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	17.11	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Particulate matter, filterable (FPM)	500	H/YR	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	17.11	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Particulate matter, filterable (FPM)	500	H/YR	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	17.11	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	17.11	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	17.11	EUEMENGINE: Emergency engine	07/16/2018	Particulate matter, filterable (FPM)	2	MW	0.2	G/KW-H	HOURLY	State of the art combustion design

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0445	INDECK NILES, LLC	17.11	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Particulate matter, filterable (FPM)	22.68	MMBTU/H	0.2	G/KW-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0448	GRAYLING PARTICLEBOARD	17.11	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Particulate matter, filterable (FPM)	500	h/yr	0.18	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	17.11	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Particulate matter, filterable (FPM)	500	h/yr	0.66	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	17.11	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Particulate matter, filterable (FPM)	500	h/yr	0.22	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0451	MEC NORTH, LLC	17.11	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	17.11	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Particulate matter, filterable (FPM)	1341	HP	0.2	G/KW-H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	17.11	Diesel Fired Emergency Generator	03/10/2016	Particulate matter, filterable (FPM)	44	H/YR	0.26	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NY-0103	CRICKET VALLEY ENERGY CENTER	17.11	Black start generator	02/03/2016	Particulate matter, filterable (FPM)	3000	KW	0.15	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.
OH-0379	PETMIN USA INCORPORATED	17.11	Emergency Generators (P005 and P006)	02/06/2019	Particulate matter, filterable (FPM10)	3131	HP	0.15	LB/H		Tier IV engine Good combustion practices
OH-0379	PETMIN USA INCORPORATED	17.11	Emergency Generators (P005 and P006)	02/06/2019	Particulate matter, filterable (FPM2.5)	3131	HP	0.15	LB/H		Tier IV engine Good combustion practices
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	17.11	2000 kW Emergency Generator	12/23/2015	Particulate matter, filterable (FPM)	0		0.025	GM/HP-HR		
SD-0005	DEER CREEK STATION	17.11	Emergency Generator	06/29/2010	Particulate matter, filterable (FPM)	2000	Kilowatts	0			
SD-0005	DEER CREEK STATION	17.11	Fire Water Pump	06/29/2010	Particulate matter, filterable (FPM)	577	horsepower	0			
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency generator	02/06/2020	Particulate matter, filterable (FPM10)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency generator	02/06/2020	Particulate matter, filterable (FPM2.5)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency firewater pumps	02/06/2020	Particulate matter, filterable (FPM)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency firewater pumps	02/06/2020	Particulate matter, filterable (FPM10)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	17.11	Emergency firewater pumps	02/06/2020	Particulate matter, filterable (FPM2.5)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
TX-0888	ORANGE POLYETHYLENE PLANT	17.11	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Particulate matter, filterable (FPM)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0888	ORANGE POLYETHYLENE PLANT	17.11	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Particulate matter, filterable (FPM10)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	17.11	EMERGENCY GENERATOR	09/09/2020	Particulate matter, filterable (FPM)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	17.11	EMERGENCY GENERATOR	09/09/2020	Particulate matter, filterable (FPM10)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	17.11	EMERGENCY GENERATOR	09/09/2020	Particulate matter, filterable (FPM2.5)	0		0			100 HOURS OPERATIONS, Tier 4 exhaust emission standards specified in 40 CFR § 1039.101
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	17.11	EMERGENCY GENERATOR	09/16/2020	Particulate matter, filterable (FPM)	0		0			limited to 100 hours per year of non-emergency operation
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	17.11	EMERGENCY GENERATOR	09/16/2020	Particulate matter, filterable (FPM10)	0		0			limited to 100 hours per year of non-emergency operation
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	17.11	EMERGENCY GENERATOR	09/16/2020	Particulate matter, filterable (FPM2.5)	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	17.11	DIESEL GENERATOR	03/17/2021	Particulate matter, filterable (FPM)	0		0.022	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0915	UNIT 5	17.11	DIESEL GENERATOR	03/17/2021	Particulate matter, filterable (FPM10)	0		0.022	G/HPHR		LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	17.11	Emergency Generators	11/17/2021	Particulate matter, filterable (FPM)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0933	NACERO PENWELL FACILITY	17.11	Emergency Generators	11/17/2021	Particulate matter, filterable (FPM10)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards

Table D-4.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Type	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0933	NACERO PENWELL FACILITY	17.11	Emergency Generators	11/17/2021	Particulate matter, filterable (FPM2.5)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	17.11	EMERGENCY GENERATOR	03/13/2023	Particulate matter, filterable (FPM)	18.7	MMBTU/HR	0.0003	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	17.11	EMERGENCY GENERATOR	03/13/2023	Particulate matter, filterable (FPM10)	18.7	MMBTU/HR	0.0003	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	17.11	EMERGENCY GENERATOR	03/13/2023	Particulate matter, filterable (FPM2.5)	18.7	MMBTU/HR	0.003	LB/HP HR		GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
VA-0328	C4GT, LLC	17.11	Emergency Diesel GEN	04/26/2018	Particulate matter, filterable (FPM)	500	H/YR	0.15	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	17.11	Emergency Diesel Generator - 300 kW	06/24/2019	Particulate matter, filterable (FPM)	500	H/YR	0.15	G/HP-H		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.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	17.11	Emergency Generator	11/21/2014	Particulate matter, filterable (FPM2.5)	2015.7	HP	0			

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM10)	143.5	MMBtu/hr	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM2.5)	143.5	MMBtu/hr	0.29	G/KW-HR (ULSD)	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Particulate matter, total (TPM10)	1500	kWe	0.25	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Particulate matter, total (TPM2.5)	1500	kWe	0.25	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Particulate matter, total (TPM10)	186.6	gph	0.045	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year.
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Particulate matter, total (TPM2.5)	186.6	gph	0.045	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year.
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Particulate matter, total (TPM10)	27.9	Gal/hr	0.19	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Particulate matter, total (TPM2.5)	27.9	Gal/hr	0.19	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Particulate matter, total (TPM10)	0		0.02	G/KW-H		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Particulate matter, total (TPM2.5)	0		0.02	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Particulate matter, total (TPM10)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0163	BIG RIVER STEEL LLC	Emergency Engines	06/09/2019	Particulate matter, total (TPM2.5)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Particulate matter, total (TPM10)	3634	Horsepower	0.2	G/KW-HR		
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Particulate matter, total (TPM2.5)	3634	Horsepower	0.2	G/KW-HR		
AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Particulate matter, total (TPM10)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Particulate matter, total (TPM2.5)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Particulate matter, total (TPM10)	3985	hp	0.2	G/KW-HR	3-HR AVG	
IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Particulate matter, total (TPM2.5)	3985	hp	0.2	G/KW-HR	3-HR AVG	
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Particulate matter, total (TPM10)	3600	HP EACH	0.15	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0263	MIDWEST FERTILIZER COMPANY LLC	EMERGENCY GENERATORS (EU014A AND EU-014B)	03/23/2017	Particulate matter, total (TPM2.5)	3600	HP EACH	0.15	G/HP-H EACH	3 HOUR AVERAGE	GOOD COMBUSTION PRACTICES
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Particulate matter, total (TPM10)	2800	HP	0.2	G/KWH		Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Particulate matter, total (TPM2.5)	2800	HP	0.2	G/KWH		Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Particulate matter, total (TPM10)	750	HP	0.2	G/KWH		Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Particulate matter, total (TPM2.5)	750	HP	0.2	G/KWH		Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Particulate matter, total (TPM10)	3600	HP	0.15	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Particulate matter, total (TPM2.5)	3600	HP	0.15	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Particulate matter, total (TPM10)	500	HP	0.15	G/HP-HR		
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Particulate matter, total (TPM2.5)	500	HP	0.15	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Particulate matter, total (TPM10)	3000	Horsepower	0.15	G/HP-H		certified engine
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Particulate matter, total (TPM2.5)	3000	Horsepower	0.15	G/HP-H		certified engine
IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Particulate matter, total (TPM10)	420	brake hp	0.2	G/KW-HR)		
IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Particulate matter, total (TPM2.5)	420	brake hp	0.2	G/KW-HR		
IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Particulate matter, total (TPM10)	2012	hp	0.15	G PER HP-HR		
IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Particulate matter, total (TPM2.5)	2012	hp	0.15	G/HP-HR		

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, & #3 (EU72, EU73, & EU74)	10/24/2016	Particulate matter, total (TPM2.5)	53.6	gal/hr	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	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 practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Emergency Generators #1, #2, &; #3 (EU72, EU73, & EU74)	10/24/2016	Particulate matter, total (TPM10)	53.6	gal/hr	0.149	G/HP-HR (EU72 &EU73)	REQ. MANUFACTURER'S CERT.	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 practices determined as BACT for minimizing CO, VOC, PM, PM10, and PM2.5 emissions. Any revisions requested by the Division shall be made and the plan shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: i. A list of combustion optimization practices and a means of verifying the practices have occurred. ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred. iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Particulate matter, total (TPM10)	920	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Particulate matter, total (TPM2.5)	920	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	700	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	700	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Particulate matter, total (TPM10)	2922	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	New Pumphouse (XB13) Emergency Generator #1 (EP 08-05)	04/19/2021	Particulate matter, total (TPM2.5)	2922	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Particulate matter, total (TPM10)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Tunnel Furnace Emergency Generator (EP 08-06)	04/19/2021	Particulate matter, total (TPM2.5)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Particulate matter, total (TPM10)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Caster B Emergency Generator (EP 08-07)	04/19/2021	Particulate matter, total (TPM2.5)	2937	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Particulate matter, total (TPM10)	700	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Unit Emergency Generator (EP 08-08)	04/19/2021	Particulate matter, total (TPM2.5)	700	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Particulate matter, total (TPM2.5)	1341	HP	0.44	LB/HR	HOURLY MAXIMUM	Use of a certified engine, low sulfur diesel, and limiting non-emergency use to no more than 100 hours per year
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Particulate matter, total (TPM10)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Particulate matter, total (TPM2.5)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Particulate matter, total (TPM2.5)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Particulate matter, total (TPM10)	0		0			good combustion practices, Use ultra low sulfur diesel, and comply with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Particulate matter, total (TPM10)	2922	hp (each)	0.2	G/KW-HR		Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Particulate matter, total (TPM2.5)	2922	hp (each)	0.2	G/KW-HR		Complying with 40 CFR 60 Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Particulate matter, total (TPM10)	650	horsepower	0.15	LB/HR		Compliance with NSPS Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Particulate matter, total (TPM2.5)	650	horsepower	0.15	LB/HR		Compliance with NSPS IIII
LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Particulate matter, total (TPM10)	1474	horsepower	0.08	LB/HR		Compliance with NSPS Subpart IIII
LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Particulate matter, total (TPM2.5)	1474	horsepower	0.08	LB/HR		Compliance with NSPS Subpart IIII

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Particulate matter, total (TPM10)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Particulate matter, total (TPM2.5)	3353	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Particulate matter, total (TPM10)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Particulate matter, total (TPM2.5)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Particulate matter, total (TPM10)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Particulate matter, total (TPM2.5)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0318	FLOPAM FACILITY	Diesel Engines	01/07/2016	Particulate matter, total (TPM10)	0		0			Complying with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Particulate matter, total (TPM10)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Particulate matter, total (TPM2.5)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Particulate matter, total (TPM10)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Particulate matter, total (TPM2.5)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (50kW)	09/21/2018	Particulate matter, total (TPM10)	5364	HP	0.2	G/KW-H		Good combustion and operating practices.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (50kW)	09/21/2018	Particulate matter, total (TPM2.5)	5364	HP	0.2	G/KW-H		Good combustion and operating practices.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Particulate matter, total (TPM10)	634	kW	0.3	G/HP-H		Good combustion and operating practices.
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Particulate matter, total (TPM2.5)	634	kW	0.3	G/HP-H		Good combustion and operating practices.
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0350	BENTELER STEEL TUBE FACILITY	emergency generators (3 units) EQT0039, EQT0040, EQT0041	03/28/2018	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Particulate matter, total (TPM10)	550	hp	0			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.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Particulate matter, total (TPM10)	550	hp	0			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.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Particulate matter, total (TPM2.5)	550	hp	0			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.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator A	05/04/2021	Particulate matter, total (TPM10)	1389	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0379	SHINTECH PLAQUEMINES PLANT 1	C/A Emergency Generator B	05/04/2021	Particulate matter, total (TPM10)	1800	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Particulate matter, total (TPM10)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0382	BIG LAKE FUELS METHANOL PLANT	Emergency Engines (EQT0014 - EQT0017)	04/25/2019	Particulate matter, total (TPM2.5)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Particulate matter, total (TPM10)	575	hp	0.23	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Particulate matter, total (TPM2.5)	575	hp	0.23	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Particulate matter, total (TPM10)	2937	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Particulate matter, total (TPM2.5)	2937	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII (Tier 2 non-road engines) standards, good combustion practices, and the use of ultra-low sulfur diesel fuel
LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Particulate matter, total (TPM2.5)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Particulate matter, total (TPM10)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices and compliance with NSPS Subpart IIII
LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Particulate matter, total (TPM2.5)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII, and limiting non-emergency operation to no more than 100 hours per year
LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Particulate matter, total (TPM10)	670.5	horsepower	0.22	LB/HR	HOURLY MAXIMUM	Use of good combustion practices, compliance with NSPS Subpart IIII, and limiting non-emergency operation to no more than 100 hours per year
LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Particulate matter, total (TPM10)	3634	horsepower	1.19	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	EGEN - Plant Emergency Generator	12/20/2023	Particulate matter, total (TPM2.5)	3634	horsepower	1.19	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM2.5)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 01 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM10)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM2.5)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	E. GEN 02 - Generac SD 2000	12/20/2023	Particulate matter, total (TPM10)	2923	horsepower	0.84	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MA-0043	MIT CENTRAL UTILITY PLANT	Cold Start Engine	06/21/2017	Particulate matter, total (TPM10)	19.04	MMBTU/HR	0.4	LB/HR		
MA-0043	MIT CENTRAL UTILITY PLANT	Cold Start Engine	06/21/2017	Particulate matter, total (TPM2.5)	19.04	MMBTU/HR	0.4	LB/HR		
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Particulate matter, total (TPM10)	500	H/YR	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Particulate matter, total (TPM2.5)	500	H/YR	0.18	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Particulate matter, total (TPM10)	500	H/YR	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME.	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Particulate matter, total (TPM2.5)	500	H/YR	1.41	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Particulate matter, total (TPM10)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Particulate matter, total (TPM2.5)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices.
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Particulate matter, total (TPM10)	500	H/YR	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Particulate matter, total (TPM2.5)	500	H/YR	0.18	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Particulate matter, total (TPM10)	500	H/YR	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Particulate matter, total (TPM2.5)	500	H/YR	0.66	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines, good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Particulate matter, total (TPM10)	500	H/YR	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Particulate matter, total (TPM2.5)	500	H/YR	0.22	LB/H	TEST PROTOCOL SHALL SPECIFY	Certified engines. Good design, operation and combustion practices. Operational restrictions/limited use.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Particulate matter, total (TPM10)	2	MW	1.18	LB/H	HOURLY	State of the art combustion design
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Particulate matter, total (TPM2.5)	2	MW	1.18	LB/H	HOURLY	State of the art combustion design.
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM10)	1500	HP	0.69	LB/H	HOURLY	Good combustion practices, burn ultra-low sulfur diesel fuel and be NSPS compliant.
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM2.5)	1500	HP	0.69	LB/H	HOURLY	Ultra low-sulfur diesel fuel.
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Particulate matter, total (TPM10)	6000	HP	2.7	LB/H	HOURLY	Good combustion practices, burn ultra low sulfur diesel fuel, and be NSPS compliant.
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Particulate matter, total (TPM2.5)	6000	HP	2.7	LB/H	HOURLY	Ultra low sulfur diesel fuel.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Particulate matter, total (TPM10)	1100	KW	7.85	LB/1000 GAL	HOURLY; EACH ENGINE	Good combustion practices and ultra low sulfur diesel
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Particulate matter, total (TPM2.5)	1100	KW	7.55	LB/1000 GAL	HOURLY; EACH ENGINE	Good combustion practices and ultra low sulfur diesel.
MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Particulate matter, total (TPM10)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices
MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Particulate matter, total (TPM2.5)	22.68	MMBTU/H	1.58	LB/H	HOURLY	Good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Particulate matter, total (TPM10)	4474.2	KW	1	LB/H	HOURLY	Good combustion practices, burn ultra-low diesel fuel and be NSPS compliant.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Particulate matter, total (TPM2.5)	4474.2	KW	1	LB/H	HOURLY	ultra-low sulfur diesel fuel
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Particulate matter, total (TPM10)	500	h/yr	0.18	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Particulate matter, total (TPM2.5)	500	h/yr	0.18	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Particulate matter, total (TPM10)	500	h/yr	0.66	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Particulate matter, total (TPM2.5)	500	h/yr	0.66	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Particulate matter, total (TPM10)	500	h/yr	0.22	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Particulate matter, total (TPM2.5)	500	h/yr	0.22	LB/H	HOURLY	Certified Engines, Good Design, Operation, and Combustion Practices, Operational Restrictions/Limited Use
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM10)	1341	HP	0.54	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Particulate matter, total (TPM2.5)	1341	HP	0.52	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Particulate matter, total (TPM10)	4474.2	KW	1	LB/H	HOURLY	Good combustion practices, burn ultra-low diesel fuel, and be NSPS compliant.
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Particulate matter, total (TPM2.5)	4474.2	KW	1	LB/H	HOURLY	Ultra-low sulfur diesel fuel
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Diesel Fired Emergency Generator	03/10/2016	Particulate matter, total (TPM10)	44	H/YR	0.26	LB/H		use of ULSD a clean burning fuel, and limited hours of operation

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Diesel Fired Emergency Generator	03/10/2016	Particulate matter, total (TPM2.5)	44	H/YR	0.26	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Particulate matter, total (TPM10)	1100	KW	0.77	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Particulate matter, total (TPM2.5)	1100	KW	0.77	LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Particulate matter, total (TPM10)	2346	HP	0.77	LB/H		State-of-the-art combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Particulate matter, total (TPM2.5)	2346	HP	0.77	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Particulate matter, total (TPM10)	2947	HP	0.97	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Particulate matter, total (TPM2.5)	2947	HP	0.97	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Particulate matter, total (TPM10)	5000	HP	0.2	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Particulate matter, total (TPM2.5)	5000	HP	0.2	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Particulate matter, total (TPM10)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Particulate matter, total (TPM2.5)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Particulate matter, total (TPM10)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Particulate matter, total (TPM2.5)	1529	HP	0.5	LB/H		Ultra low sulfur diesel fuel
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Particulate matter, total (TPM10)	2206	HP	0.73	LB/H		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.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Particulate matter, total (TPM2.5)	2206	HP	0.73	LB/H		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.
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Particulate matter, total (TPM10)	2206	HP	0.73	LB/H		Good combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Particulate matter, total (TPM2.5)	2206	HP	0.73	LB/H		Good combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Particulate matter, total (TPM10)	700	HP	0.23	LB/H		Good combustion design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Particulate matter, total (TPM2.5)	700	HP	0.23	LB/H		Good combustion design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Particulate matter, total (TPM10)	2682	HP	1.01	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Particulate matter, total (TPM2.5)	2682	HP	1.01	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Particulate matter, total (TPM10)	1860	HP	0.62	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Particulate matter, total (TPM2.5)	1860	HP	0.62	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Particulate matter, total (TPM10)	3353	HP	1.1	LB/H		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
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Particulate matter, total (TPM2.5)	3353	HP	1.1	LB/H		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
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Particulate matter, total (TPM10)	1341	HP	0.44	LB/H		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
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Particulate matter, total (TPM2.5)	1341	HP	0.44	LB/H		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
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Particulate matter, total (TPM10)	3131	HP	0.15	G/B-HP-H		Tier IV engine and Good combustion practices
OH-0383	PETMIN USA INCORPORATED	Diesel-fired emergency fire pumps (2) (P009 and P010)	07/17/2020	Particulate matter, total (TPM2.5)	3131	HP	0.15	G/B-HP-H		Tier IV engine and Good combustion practices
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Particulate matter, total (TPM10)	5051	HP	0.07	LB/H	EACH GENERATOR	Certified to meet Tier 2 standards and good combustion practices
OH-0387	INTEL OHIO SITE	5,051 bhp (3,768 kWm) Diesel-Fired Emergency Generators: P001 through P046	09/20/2022	Particulate matter, total (TPM2.5)	5051	HP	0.07	LB/H	EACH GENERATOR	Certified to meet Tier 2 standards and good combustion practices
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Particulate matter, total (TPM10)	0		0.025	GM/HP-HR		

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Particulate matter, total (TPM2.5)	0		0.025	GM/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Particulate matter, total (TPM10)	0		0.04	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Particulate matter, total (TPM2.5)	0		0.04	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Particulate matter, total (TPM10)	0		0.2	G/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Particulate matter, total (TPM2.5)	0		2	HP-HR		
SC-0193	MERCEDES BENZ VANS, LLC	Emergency Generators and Fire Pump	04/15/2016	Particulate matter, total (TPM2.5)	1500	hp	100	HR/YR	12 MONTH ROLLING SUM	Meet the standards of 40 CFR 60, Subpart IIII
SC-0193	MERCEDES BENZ VANS, LLC	Emergency Generators and Fire Pump	04/15/2016	Particulate matter, total (TPM10)	1500	hp	100	HR/YR	12 MONTH ROLLING SUM	Must meet the standards of 40 CFR 60, Subpart IIII
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Particulate matter, total (TPM2.5)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Particulate matter, total (TPM10)	500	H/YR	0.15	G/HP H		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Particulate matter, total (TPM2.5)	500	H/YR	0.15	G/HP H		Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Particulate matter, total (TPM10)	500	H/YR	0.15	G/HP-HR		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.
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Particulate matter, total (TPM2.5)	500	H/YR	0.15	G/HP-HR		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.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0333	NORFOLK NAVAL SHIPYARD	One (1) emergency engine generator	12/09/2020	Particulate matter, total (TPM10)	2220	HP	1.1	LB	HR	
VA-0333	NORFOLK NAVAL SHIPYARD	One (1) emergency engine generator	12/09/2020	Particulate matter, total (TPM2.5)	2220	HP	1.1	LB	HR	
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Particulate matter, total (TPM10)	0		0.17	G/KWH		The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Particulate matter, total (TPM2.5)	0		0.17	G/KWH		The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Particulate matter, total (TPM10)	0		0.17	G/KWH		Good Combustion Practices and The Use of Ultra-low Sulfur Fuel
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Particulate matter, total (TPM2.5)	0		0.17	G/KWH		Good Combustion Practices and The Use of Ultra-low Sulfur Fuel
WI-0294	CARDINAL FG COMPANY	P10- Diesel emergency Generator	08/26/2019	Particulate matter, total (TPM2.5)	0		0.05	G/BHP-H		
WI-0294	CARDINAL FG COMPANY	P10- Diesel emergency Generator	08/26/2019	Particulate matter, total (TPM10)	0		0.05	G/BHP-H		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Particulate matter, total (TPM10)	1490	HP	0.15	G/HP-H		Limited to operate 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and operate and maintain according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Particulate matter, total (TPM2.5)	1490	HP	0.15	G/HP-H		Limited to operate 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and operate and maintain according to the manufacturer's recommendations.

Table D-4.5 Summary of Total PM10/PM2.5 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WV-0027	INWOOD	Emergency Generator - ESDG14	09/15/2017	Particulate matter, total (TPM10)	900	bhp	0.2	G/HP-HR		ULSD

Table D-4.6 Summary of H_2SO_4 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Sulfuric Acid (mist, vapors, etc)	1250	kW	0			Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.
IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Sulfuric Acid (mist, vapors, etc)	420	brake hp	0.0002	LB PER MMBTU		
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Sulfuric Acid (mist, vapors, etc)	2	MW	15	PPM	FUEL SUPPLIER RECORDS OR TEST DATA	Good combustion practices, low sulfur fuel.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Sulfuric Acid (mist, vapors, etc)	1100	KW	2.19	X10-3 LB/H		Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Sulfuric Acid (mist, vapors, etc)	2346	HP	5.1	X10-4 LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Sulfuric Acid (mist, vapors, etc)	2947	HP	6.4	X10-4 LB/H		Ultra low sulfur diesel fuel
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Sulfuric Acid (mist, vapors, etc)	1529	HP	3.3	X10-4 LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Sulfuric Acid (mist, vapors, etc)	1529	HP	3.3	X10-4 LB/H		Ultra low sulfur diesel fuel
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Sulfuric Acid (mist, vapors, etc)	2206	HP	3.4	X10-3 LB/H		ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight)
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Sulfuric Acid (mist, vapors, etc)	2206	HP	0.0016	LB/H		Low sulfur fuel
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Sulfuric Acid (mist, vapors, etc)	700	HP	5.4	X10-4 LB/H		Low sulfur fuel
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	1860	HP	7.3	X10-4 LB/MMBTU		ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight)
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Sulfuric Acid (mist, vapors, etc)	0		0.0007	GM/HP-HR		
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Sulfuric Acid (mist, vapors, etc)	0		0.0006	G/HP-HR		
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Sulfuric Acid (mist, vapors, etc)	500	H/YR	0			good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

Table D-4.6 Summary of H_2SO_4 BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Sulfuric Acid (mist, vapors, etc)	500	H/YR	0.0001	LB/MMBTU		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.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	1490	HP	0			Operation limited to 500 hours/year, sulfur content of the diesel fuel oil fired may not exceed 15 ppm, and permittee shall operate and maintain generator according to the manufacturer's recommendations.

Table D-4.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Emergency Camp Generators	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	2695	hp	2332	TONS/YEAR	COMBINED	
AK-0082	POINT THOMSON PRODUCTION FACILITY	Fine Water Pumps	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	610	hp	565	TONS/YEAR	COMBINED	
AK-0082	POINT THOMSON PRODUCTION FACILITY	Bulk Tank Generator Engines	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	891	hp	7194	TONS/YEAR	COMBINED	
AK-0084	DONLIN GOLD PROJECT	Twelve (12) Large ULSD/Natural Gas-Fired Internal Combustion Engines	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	143.5	MMBtu/hr	1299630	TPY (ULSD)		Good Cumbustion Practices
AK-0084	DONLIN GOLD PROJECT	Black Start and Emergency Internal Cumbustion Engines	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	1500	kWe	2781	TPY	YEARLY	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	One (1) Black Start Generator Engine	08/13/2020	Carbon Dioxide Equivalent (CO_2e)	186.6	gph	163.6	LB/MMBTU	3-HOUR AVERAGE	Good combustion practices and limit operation to 500 hours per year
AK-0088	LIQUEFACTION PLANT	Diesel Fire Pump Engine	07/07/2022	Carbon Dioxide Equivalent (CO_2e)	27.9	Gal/hr	163.6	LB/MMBTU	3-HOURS	Good Combustion Practices; Limited Operation;
AR-0161	SUN BIO MATERIAL COMPANY	Emergency Engines	09/23/2019	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good Combustion Practices
AR-0177	NUCOR STEEL ARKANSAS	SN-230 Galvanizing Line No, 2 Emergency Generator	11/21/2022	Carbon Dioxide Equivalent (CO_2e)	3634	Horsepower	163	LB/MMBTU		
AR-0180	HYBAR LLC	Emergency Generators	04/28/2023	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good combustion practices
IL-0129	CPV THREE RIVERS ENERGY CENTER	Emergency Engines	07/30/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			
IL-0130	JACKSON ENERGY CENTER	Emergency Engine	12/31/2018	Carbon Dioxide Equivalent (CO_2e)	1500	kW	225	TONS/YEAR		
IL-0133	LINCOLN LAND ENERGY CENTER	Emergency Engines	07/29/2022	Carbon Dioxide Equivalent (CO_2e)	1250	kW	508	TONS/YEAR		
IL-0134	CRONUS CHEMICALS	Emergency Generator Engine	12/21/2023	Carbon Dioxide Equivalent (CO_2e)	3985	hp	160	TONS/YEAR		
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency generator EU-6006	06/11/2019	Carbon Dioxide Equivalent (CO2e)	2800	HP	811	TONS	12 CONSECUTIVE MONTHS	Tier II diesel engine
IN-0317	RIVERVIEW ENERGY CORPORATION	Emergency fire pump EU-6008	06/11/2019	Carbon Dioxide Equivalent (CO_2e)	750	HP	217	TONS	12 CONSECUTIVE MONTHS	Engine that complies with Table 4 to Subpart IIII of Part 60
IN-0324	MIDWEST FERTILIZER COMPANY LLC	emergency generator EU 014a	05/06/2022	Carbon Dioxide Equivalent (CO_2e)	3600	HP	1044	TON/YR	TWELVE CONSECUTIVE MONTH PERIOD	
IN-0324	MIDWEST FERTILIZER COMPANY LLC	fire water pump EU-015	05/06/2022	Carbon Dioxide Equivalent (CO_2e)	500	HP	527.4	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN1)	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	3000	Horsepower	163.6	LB/MMBTU		Good engineering design and manufacturer's recommended operating and maintenance procedures.
IN-0365	MAPLE CREEK ENERGY LLC	Emergency fire pump	06/19/2023	Carbon Dioxide Equivalent (CO_2e)	420	brake hp	123	TONS PER YEAR		

Table D-4.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0365	MAPLE CREEK ENERGY LLC	Emergency generator	06/19/2023	Carbon Dioxide Equivalent (CO_2e)	2012	hp	625	TONS PER YEAR		
IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (400 kW)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	619	HP	180	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (1000 kW)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	1000	kW	389	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
IN-0371	WABASH VALLEY RESOURCES, LLC	Emergency Generator (2000 kW)	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	2000	kW	778	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
IN-0371	WABASH VALLEY RESOURCES, LLC	Ammonia Plant Emergency Generator	01/11/2024	Carbon Dioxide Equivalent (CO_2e)	500	kW	219	TONS	PER TWELVE (12) CONSECUTIVE MONTH PERIOD	Good Combustion Practices
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-04 - Emergency Fire Water Pump	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	920	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-02 - North Water System Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-03 - South Water System Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-07 - Air Separation Plant Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	700	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 10-01 - Caster Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	2922	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
LA-0292	HOLBROOK COMPRESSOR STATION	Emergency Generators No. 1 & No. 2	01/22/2016	Carbon Dioxide Equivalent (CO_2e)	1341	HP	77	TPY	ANNUAL MAXIMUM	
LA-0305	LAKE CHARLES METHANOL FACILITY	Diesel Engines (Emergency)	06/30/2016	Carbon Dioxide Equivalent (CO_2e)	4023	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0307	MAGNOLIA LNG FACILITY	Diesel Engines	03/21/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			good combustion/operating/maintenance practices
LA-0309	BENTELER STEEL TUBE FACILITY	Emergency Generator Engines	06/04/2015	Carbon Dioxide Equivalent (CO_2e)	2922	hp (each)	0			
LA-0312	ST. JAMES METHANOL PLANT	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	650	horsepower	37	TPY		Compliance with NSPS Subpart IIII

Table D-4.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0312	ST. JAMES METHANOL PLANT	DEG1-13 - Diesel Fired Emergency Generator Engine (EQT0012)	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	1474	horsepower	84	TPY		Compliance with NSPS Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Generator 1	08/31/2016	Carbon Dioxide Equivalent (CO_2e)	2584	HP	0			Good combustion practices
LA-0316	CAMERON LNG FACILITY	emergency generator engines (6 units)	02/17/2017	Carbon Dioxide Equivalent (CO_2e)	3353	hp	0			good combustion practices
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Emergency Generator Engines (4 units)	12/22/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0317	METHANEX - GEISMAR METHANOL PLANT	Firewater pump Engines (4 units)	12/22/2016	Carbon Dioxide Equivalent (CO_2e)	896	hp (each)	0			complying with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 4 Engine	01/09/2017	Carbon Dioxide Equivalent (CO_2e)	600	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Fire Water Diesel Pump No. 3 Engine	01/09/2017	Carbon Dioxide Equivalent (CO_2e)	600	hp	0			Proper operation and limits on hours operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0331	CALCASIEU PASS LNG PROJECT	Large Emergency Engines (>50kW)	09/21/2018	Carbon Dioxide Equivalent (CO_2e)	5364	HP	1481	T/YR	ANNUAL TOTAL	Good Combustion of Practices and Good Operation and Maintenance Practices
LA-0331	CALCASIEU PASS LNG PROJECT	Firewater Pumps	09/21/2018	Carbon Dioxide Equivalent (CO_2e)	634	kW	44	T/YR	ANNUAL TOTAL	Good Combustion Practices and Good Operation and Maintenance Practices.
LA-0364	FG LA COMPLEX	Emergency Generator Diesel Engines	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	550	hp	0			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.
LA-0364	FG LA COMPLEX	Emergency Fire Water Pumps	01/06/2020	Carbon Dioxide Equivalent (CO_2e)	550	hp	0			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.
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Emergency Engines (EQT0011 - EQT0016)	09/03/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0388	LACC LLC US - ETHYLENE PLANT	Firewater Pump Engine No. 1 and 2	02/25/2022	Carbon Dioxide Equivalent (CO_2e)	575	hp	33	T/YR		Compliance with 40 CFR 60 Subpart IIII

Table D-4.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Generator Engine	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	2937	hp	74.21	KG/MMBTU		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
LA-0394	GEISMAR PLANT	06-22 - AO-5 Emergency Generator	12/12/2023	Carbon Dioxide Equivalent (CO_2e)	670.5	horsepower	0			Use of good combustion practices and compliance with NSPS Subpart IIII
LA-0394	GEISMAR PLANT	53-22 - PAO Emergency Generator	12/12/2023	Carbon Dioxide Equivalent (CO_2e)	670.5	horsepower	0			Use of good combustion practices, compliance with NSPS Subpart IIII
MA-0043	MIT CENTRAL UTILITY PLANT	Cold Start Engine	06/21/2017	Carbon Dioxide Equivalent (CO_2e)	19.04	MMBTU/HR	163.61	LB/MMBTU		
MI-0421	GRAYLING PARTICLEBOARD	Dieself fire pump engine (EUFIREPUMP in FGRICE)	08/26/2016	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	56	T/YR	BASED UPON A 12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0421	GRAYLING PARTICLEBOARD	Emergency Diesel Generator Engine (EUEMRGRICE in FGRICE)	08/26/2016	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	223	T/YR	BASED UPON A 12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0423	INDECK NILES, LLC	EUEMENGINE (Diesel fuel emergency engine)	01/04/2017	Carbon Dioxide Equivalent (CO_2e)	22.68	MMBTU/H	928	T/YR	12-MO. ROLLING TIME PERIOD	Good combustion practices
MI-0425	GRAYLING PARTICLEBOARD	EUFIREPUMP in FGRICE (Diesel fire pump engine)	05/09/2017	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	56	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE1 in FGRICE (Emergency diesel generator engine)	05/09/2017	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	209	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0425	GRAYLING PARTICLEBOARD	EUEMRGRICE2 in FGRICE (Emergency Diesel Generator Engine)	05/09/2017	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	70	T/YR	12-MO ROLLING TIME PERIOD	Good combustion and design practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (North Plant): Emergency Engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO. ROLLING TIME PERIOD	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUEMENGINE (South Plant): Emergency Engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUEMENGINE: Emergency engine	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	2	MW	161	T/YR	12-MO ROLLING TIME PERIOD	Energy efficient design.
MI-0441	LBWL--ERICKSON STATION	EUEMGD1--A 1500 HP diesel fueled emergency engine	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	1500	HP	406	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices and energy efficiency measures.
MI-0441	LBWL--ERICKSON STATION	EUEMGD2--A 6000 HP diesel fuel fired emergency engine	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	6000	HP	1590	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices and energy efficiency measures.
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGEMENGINE	08/21/2019	Carbon Dioxide Equivalent (CO_2e)	1100	KW	444	T/YR	12-MO ROLL. TIME PERIOD; EACH ENGINE	
MI-0445	INDECK NILES, LLC	EUEMENGINE (diesel fuel emergency engine)	11/26/2019	Carbon Dioxide Equivalent (CO_2e)	22.68	MMBTU/H	928	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUEMGD--emergency engine	01/07/2021	Carbon Dioxide Equivalent (CO_2e)	4474.2	KW	590	T/YR	12-MO ROLLING TIME PERIOD	low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.

Table D-4.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0448	GRAYLING PARTICLEBOARD	Diesel fire pump engine (EUFIREPUMP in FGRICE)	12/18/2020	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	56	T/YR	12-MO ROLLING TIME PERIOD	Good Combustion and Design Practices
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE1 in FGRICE)	12/18/2020	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	590	T/YR	12-MO ROLLING TIME PERIOD	Good Combustion and Design Practices
MI-0448	GRAYLING PARTICLEBOARD	Emergency diesel generator engine (EUEMRGRICE2 in FGRICE)	12/18/2020	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	209	T/YR	12-MO ROLLING TIME PERIOD	Good Combustion and Design Practices
MI-0451	MEC NORTH, LLC	EUEMENGINE (North Plant): Emergency engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0452	MEC SOUTH, LLC	EUEMENGINE (South Plant): Emergency engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	1341	HP	383	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0454	LBWL-ERICKSON STATION	EUEMGD	12/20/2022	Carbon Dioxide Equivalent (CO_2e)	4474.2	KW	590	T/YR	12-MO ROLLING TIME PERIOD	low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
OH-0363	NTE OHIO, LLC	Emergency generator (P002)	11/05/2014	Carbon Dioxide Equivalent (CO_2e)	1100	KW	474	T/YR	PER ROLLING 12 MONTH PERIOD	Emergency operation only, < 500 hours/year each for maintenance checks and readiness testing designed to meet NSPS Subpart IIII
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency generator (P003)	08/25/2015	Carbon Dioxide Equivalent (CO_2e)	2346	HP	683	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency generator (P003)	09/23/2016	Carbon Dioxide Equivalent (CO_2e)	2947	HP	858	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0368	PALLAS NITROGEN LLC	Emergency Generator (P009)	04/19/2017	Carbon Dioxide Equivalent (CO_2e)	5000	HP	1289	T/YR	PER ROLLING 12 MONTH PERIOD	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency generator (P003)	09/07/2017	Carbon Dioxide Equivalent (CO_2e)	1529	HP	445	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0372	OREGON ENERGY CENTER	Emergency generator (P003)	09/27/2017	Carbon Dioxide Equivalent (CO_2e)	1529	HP	445	T/YR	PER ROLLING 12 MONTH PERIOD	state of the art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Generators (2 identical, P004 and P005)	10/23/2017	Carbon Dioxide Equivalent (CO_2e)	2206	HP	120	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Generator Engine (P001)	11/07/2017	Carbon Dioxide Equivalent (CO_2e)	2206	HP	116.8	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Emergency Diesel Fire Pump Engine (P002)	11/07/2017	Carbon Dioxide Equivalent (CO_2e)	700	HP	40.1	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fired generator (P007)	02/09/2018	Carbon Dioxide Equivalent (CO_2e)	2682	HP	163.6	LB/MMBTU		Equipment design and maintenance requirements
OH-0377	HARRISON POWER	Emergency Diesel Generator (P003)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	1860	HP	109.2	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design and proper maintenance and operation
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Emergency Diesel-fired Generator Engine (P007)	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	3353	HP	200	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)

Table D-4.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	1,000 kW Emergency Generators (P008 - P010)	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	1341	HP	80	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
OH-0379	PETMIN USA INCORPORATED	Emergency Generators (P005 and P006)	02/06/2019	Carbon Dioxide Equivalent (CO_2e)	3131	HP	3632	LB/H		Tier IV engine Good combustion practices
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	2000 kW Emergency Generator	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	0		81	TONS	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	Emergency Generator	09/01/2015	Carbon Dioxide Equivalent (CO_2e)	0		44	TPY	12-MONTH ROLLING BASIS	
PA-0311	MOXIE FREEDOM GENERATION PLANT	Fire Pump Engine	09/01/2015	Carbon Dioxide Equivalent (CO_2e)	0		14	TPY	12-MONTH ROLLING BASIS	
TX-0766	GOLDEN PASS LNG EXPORT TERMINAL	Emergency Engine Generators	09/11/2015	Carbon Dioxide Equivalent (CO_2e)	750	hp	40	HR/YR		Equipment specifications & work practices - Good combustion practices and limited operational hours
TX-0799	BEAUMONT TERMINAL	Fire pump engines	06/08/2016	Carbon Dioxide Equivalent (CO_2e)	0		72.16	T/YR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0872	CONDENSATE SPLITTER FACILITY	Emergency Generators	10/31/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			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.
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency generator	02/06/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Tier 4 exhaust emission standards specified in 40 CFR § 1039.101, limited to 100 hours per year of non-emergency operation
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	Emergency firewater pumps	02/06/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Tier 3 exhaust emission standards specified in 40 CFR § 89.112, limited to 100 hours per year of non-emergency operation
TX-0888	ORANGE POLYETHYLENE PLANT	EMERGENCY GENERATORS & FIRE WATER PUMP ENGINES	04/23/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			well-designed and properly maintained engines and each limited to 100 hours per year of non-emergency use.
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	EMERGENCY GENERATOR	09/16/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			limited to 100 hours per year of non-emergency operation
TX-0915	UNIT 5	DIESEL GENERATOR	03/17/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			LIMITED 500 HR/YR OPERATION
TX-0933	NACERO PENWELL FACILITY	Emergency Generators	11/17/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			limited to 100 hours per year of non-emergency operation. EPA Tier 2 (40 CFR § 1039.101) exhaust emission standards
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	EMERGENCY GENERATOR	03/13/2023	Carbon Dioxide Equivalent (CO_2e)	18.7	MMBTU/HR	0			GOOD COMBUSTION PRACTICES, LIMITED TO 100 HR/YR
VA-0328	C4GT, LLC	Emergency Diesel GEN	04/26/2018	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	981	T/YR	12 MO ROLLING TOTAL	use of S15 ULSD and high efficiency design and operation

Table D-4.7 Summary of CO_2e BACT Determinations for Large Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0332	CHICKAHOMINY POWER LLC	Emergency Diesel Generator - 300 kW	06/24/2019	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	1203	T/YR	12 MO ROLLING TOTAL	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.
VA-0333	NORFOLK NAVAL SHIPYARD	One (1) emergency engine generator	12/09/2020	Carbon Dioxide Equivalent (CO_2e)	2220	HP	2.543	LB	HR	
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	Diesel-Fired Emergency Generators	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			The Use of Ultra-Low Sulfur Fuel and Good Combustion Practices
WI-0286	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P42 -Diesel Fired Emergency Generator	04/24/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			Good Combustion Practices and The Use of Ultra-low Sulfur Fuel
WI-0297	GREEN BAY PACKAGING- MILL DIVISION	Diesel-Fired Emergency Fire Pump (P36)	12/10/2019	Carbon Dioxide Equivalent (CO_2e)	510	HP	200	H/Y	IN ANY CONSECUTIVE 12-MONTH PERIOD	
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Generator (P07)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	1490	HP	0			Certified to at least meet EPA's criteria for Tier 2 reciprocating internal combustion engines and the 40 CFR 60, Subpart IIII emission limitations, operation limited to 500 hours/year, and operate and maintain generator according to the manufacturer's recommendations.
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Emergency Generator	11/21/2014	Carbon Dioxide Equivalent (CO_2e)	2015.7	HP	2416	LB/H		

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Nitrogen Oxides (NO_x)	490	hp	4.8	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Nitrogen Oxides (NO_x)	98	hp	5.6	GRAMS/HP-H		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Nitrogen Oxides (NO_x)	2.7	MMBTU/H	4.41	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Nitrogen Oxides (NO_x)	252	hp	3.7	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Nitrogen Oxides (NO_x)	19.4	gph	3.6	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Nitrogen Oxides (NO_x)	2.7	MMBtu/hr	4.41	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Nitrogen Oxides (NO_x)	14.6	Gal/hr	0.45	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Nitrogen Oxides (NO_x)	0		4.86	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Nitrogen Oxides (NO_x)	1073	bhp	2	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Nitrogen Oxides (NO_x)	0		3.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Nitrogen Oxides (NO_x)	0		14.06	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Nitrogen Oxides (NO_x)	0		14.06	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Nitrogen Oxides (NO_x)	29	MMBTU/H	4	G / KWH	NMHC + NOX (SUBPART IIII)	Low-emitting fuel and certified engine

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	07/27/2018	Nitrogen Oxides (NO_x)	8700	gal/year	4	G/KW-HR		Operate and maintain the engine according to the manufacturer's written instructions
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	06/07/2021	Nitrogen Oxides (NO_x)	2.46	MMBtu/hour	4	G/KW-HOUR	NMHC + NOX STANDARD	
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Nitrogen Oxides (NO_x)	320	horsepower	4	GRAMS	KILOWATT-HOUR	
IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Nitrogen Oxides (NO_x)	369	hp	4	G/KW-HR	3-HR AVG	
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Nitrogen Oxides (NO_x)	0		9.5	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Nitrogen Oxides (NO_x)	150	hp	14.06	G/HP-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Nitrogen Oxides (NO_x)	250	hp	9.2	G/KW-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Nitrogen Oxides (NO_x)	500	Horsepower	3	G/HP-HR		certified engine
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Nitrogen Oxides (NO_x)	197	HP	3	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	260	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	190	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	440	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	190	HP	2.98	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Nitrogen Oxides (NO_x)	61	HP	3.5	G/HP-HR	NMHC + NOX	This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Nitrogen Oxides (NO_x)	350	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Nitrogen Oxides (NO_x)	288	hp (each)	3	G/BHP-HR		Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Nitrogen Oxides (NO_x)	282	HP	1.87	LB/H	HOURLY MAXIMUM	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).
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Nitrogen Oxides (NO_x)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Nitrogen Oxides (NO_x)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Nitrogen Oxides (NO_x)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Nitrogen Oxides (NO_x)	375	HP	4	G/KW-H		Good combustion practices and NSPS IIII

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Nitrogen Oxides (NO_x)	300	HP	4	G/KW-H		Good combustion practices and NSPS Subpart IIII
LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Nitrogen Oxides (NO_x)	0		4	G/KW-HR	NMEHC + NOX	Compliance with 40 CFR 60 Subpart IIII
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Nitrogen Oxides (NO_x)	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Nitrogen Oxides (NO_x)	1.1	MM BTU/hr	1.15	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Nitrogen Oxides (NO_x)	450	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Nitrogen Oxides (NO_x)	439	hp	6.9	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Nitrogen Oxides (NO_x)	180	hp	2.98	G/KW-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Nitrogen Oxides (NO_x)	375	hp	4.41	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Nitrogen Oxides (NO_x)	300	hp	0.4	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII.
LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Nitrogen Oxides (NO_x)	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Nitrogen Oxides (NO_x)	0		0			Comply with 40 CFR 60 Subpart IIII

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Nitrogen Oxides (NO_x)	355	hp	3	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and use of ultra-low sulfur diesel fuel.
LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Nitrogen Oxides (NO_x)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Nitrogen Oxides (NO_x)	422	horsepower	3.96	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Nitrogen Oxides (NO_x)	422	horsepower	3.96	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Nitrogen Oxides (NO_x)	237	horsepower	1.49	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Nitrogen Oxides (NO_x)	1490	HP	6.4	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Nitrogen Oxides (NO_x)	1.66	MMBTU/H	3	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Nitrogen Oxides (NO_x)	500	H/YR	3	G/HP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Nitrogen Oxides (NO_x)	300	HP	3	G/BHP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Nitrogen Oxides (NO_x)	300	HP	3	G/BHP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0434	FLAT ROCK ASSEMBLY PLANT	EUFIREPUMPENGS (2 emergency fire pump engines)	03/22/2018	Nitrogen Oxides (NO_x)	250	BHP	3	G/B-HP-H	HOURLY; EACH ENGINE (NMHC+NOX)	Good combustion practices.
MI-0434	FLAT ROCK ASSEMBLY PLANT	EULIFESAFETYENG - One diesel-fueled emergency engine/generator	03/22/2018	Nitrogen Oxides (NO_x)	500	KW	4	G/KW-H	HOURLY; NMHC+NOX	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Nitrogen Oxides (NO_x)	399	BHP	4	G/KW-H	HOURLY	State of the art combustion design.
MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Nitrogen Oxides (NO_x)	1.66	MMBTU/H	3	G/BHP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Nitrogen Oxides (NO_x)	300	HP	3	G/B-HP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Nitrogen Oxides (NO_x)	300	HP	3	G/B-HP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Nitrogen Oxides (NO_x)	2.5	MMBTU/H	3	G/HP-H	HOURLY	Good combustion practices.
NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 2	11/21/2022	Nitrogen Oxides (NO_x)	510	hp	2.38	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Nitrogen Oxides (NO_x)	140	HP	0.81	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Nitrogen Oxides (NO_x)	311	HP	1.79	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Nitrogen Oxides (NO_x)	460	HP	0.3	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Nitrogen Oxides (NO_x)	300	HP	1.97	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Nitrogen Oxides (NO_x)	300	HP	1.97	LB/H		State-of-the-art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Nitrogen Oxides (NO_x)	410	HP	2.7	LB/H	NMHC+NOX. SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Nitrogen Oxides (NO_x)	250	HP	1.6	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Nitrogen Oxides (NO_x)	320	HP	2.12	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Nitrogen Oxides (NO_x)	402	HP	2.64	LB/H	SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Nitrogen Oxides (NO_x)	158	HP	0.104	LB/H		Tier IV engine Tier IV NSPS standards certified by engine manufacturer.
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Nitrogen Oxides (NO_x)	275	HP	4	G/KW-H	4.0 GRAMS NOX + NMHC/KW-HR	Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Nitrogen Oxides (NO_x)	225	HP	0.15	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Nitrogen Oxides (NO_x)	125	HP	0.08	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Nitrogen Oxides (NO_x)	100	HP	0.07	LB/H		Good combustion practices to meet Tier IV emissions

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Nitrogen Oxides (NO_x)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Nitrogen Oxides (NO_x)	214	kW	0.4	G/KW	HR	Meets EPA Tier 4 requirements
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Nitrogen Oxides (NO_x)	0		0			Tier 4 exhaust emission standards specified at 40 CFR Â§ 1039.101(b)
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Nitrogen Oxides (NO_x)	74	KW	100	HR/YR		Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		Good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		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.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Nitrogen Oxides (NO_x)	500	HR/YR	3	G/HP-HR		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Nitrogen Oxides (NO_x)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel, and operate <500 hr/yr
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Nitrogen Oxides (NO_x)	1.27	mmBtu/hr	0			

Table D-5.1 Summary of NO_x BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Nitrogen Oxides (NO_x)	0		5.9	LB/HR		Expected NOx emission without controls are 0.59 tons/year and 5.9 pounds/hour. Given this low rate of NOx emissions, due to the 200 hour/year operational limitation, the Department believes, based on engineering judgment, that controls are not economically feasible for this unit. Thus, the RICE MACT remains the only control option.
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K â€" Diesel Powered Emergency Generator	06/05/2015	Nitrogen Oxides (NO_x)	0		5.9	LB/HR		
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Nitrogen Oxides (NO_x)	0.22	mmBTU/hr	4.7	G/KWH		Good Combustion Practices
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Nitrogen Oxides (NO_x)	0.22	mmBTU/hr	4.7	G/KWH		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Nitrogen Oxides (NO_x)	282	HP	3	G/HP-H		Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Nitrogen Oxides (NO_x)	282	HP	3	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Nitrogen Oxides (NO_x)	290	HP	3.64	LB/H		Only use diesel fuel oil with a sulfur content of no greater than 0.0015% by weight
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Nitrogen Oxides (NO_x)	290	HP	3.64	LB/H		

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Carbon Monoxide	490	hp	2.6	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Carbon Monoxide	98	hp	3.7	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Carbon Monoxide	102	hp	3.7	GRAMS/HP-H		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Carbon Monoxide	2.7	MMBTU/H	0.95	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Carbon Monoxide	252	hp	3.3	G/KW-HR	3-HOUR AVERAGE	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Carbon Monoxide	19.4	gph	3.3	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Carbon Monoxide	2.7	MMBtu/hr	0.95	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Carbon Monoxide	14.6	Gal/hr	3.3	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Carbon Monoxide	0		3.5	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Carbon Monoxide	1073	bhp	4	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Carbon Monoxide	0		0.9	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Carbon Monoxide	0		3.03	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Carbon Monoxide	0		3.03	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Carbon Monoxide	29	MMBTU/H	3.5	G / KWH		Low-emitting fuel and certified engine
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	One 422-hp emergency fire pump engine	03/09/2016	Carbon Monoxide	0		3.5	G / KW-HR		Use of clean engine technology
FL-0363	DANIA BEACH ENERGY CENTER	Emergency Fire Pump Engine (422 hp)	12/04/2017	Carbon Monoxide	0		3.5	G / KWH		Certified engine
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	07/27/2018	Carbon Monoxide	8700	gal/year	3.5	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	06/07/2021	Carbon Monoxide	2.46	MMBtu/hour	3.5	G/KW-HOUR		
IL-0129	CPV THREE RIVERS ENERGY CENTER	Firewater Pump Engine	07/30/2018	Carbon Monoxide	0		0			
IL-0130	JACKSON ENERGY CENTER	Firewater Pump Engine	12/31/2018	Carbon Monoxide	420	horsepower	3.5	G/KW-HR		
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Carbon Monoxide	320	horsepower	3.5	GRAMS	KILOWATT-HOUR	
IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Carbon Monoxide	369	hp	3.5	G/KW-HR	3-HR AVG	
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Carbon Monoxide	0		2.01	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Carbon Monoxide	150	hp	3.08	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Carbon Monoxide	250	hp	3.08	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Carbon Monoxide	500	Horsepower	2.61	G/HP-HR		oxidation catalyst and certified engine
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Carbon Monoxide	260	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Carbon Monoxide	190	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Carbon Monoxide	440	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Carbon Monoxide	190	HP	2.61	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Carbon Monoxide	61	HP	3.73	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Carbon Monoxide	350	HP	0			The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0306	TOPCHEM POLLOCK, LLC	Genenerator Engine DEG-16-1 (EQT035)	12/20/2016	Carbon Monoxide	460	horsepower	3.18	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0306	TOPCHEM POLLOCK, LLC	Pump Engines DFP-16-1 (EQT036)	12/20/2016	Carbon Monoxide	225	horsepower	1.55	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0306	TOPCHEM POLLOCK, LLC	Pump Engine DFP-16-2 (EQT037)	12/20/2016	Carbon Monoxide	225	horsepower	1.55	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Carbon Monoxide	288	hp (each)	0			Complying with 40 CFR 60 Subpart IIII
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Carbon Monoxide	282	HP	1.62	LB/H	HOURLY MAXIMUM	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).
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Carbon Monoxide	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Carbon Monoxide	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Carbon Monoxide	460	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Carbon Monoxide	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Carbon Monoxide	375	HP	3.5			Compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Carbon Monoxide	300	HP	3.5			Compliance with 40 CFR 60 Subpart IIII

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Carbon Monoxide	0		3.5	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Carbon Monoxide	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Carbon Monoxide	1.1	MM BTU/hr	0.4	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Carbon Monoxide	450	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Carbon Monoxide	439	hp	8.5	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Carbon Monoxide	180	hp	3.5	G/KW-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Carbon Monoxide	375	hp	0.95	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Carbon Monoxide	300	hp	2.6	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII.
LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Carbon Monoxide	0		0			Comply with standards of 40 CFR 60 Subpart IIII
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Carbon Monoxide	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Carbon Monoxide	355	hp	2.6	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Carbon Monoxide	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Carbon Monoxide	422	horsepower	3.44	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Carbon Monoxide	422	horsepower	3.44	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Carbon Monoxide	237	horsepower	0.5	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Carbon Monoxide	1490	HP	3.5	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Carbon Monoxide	305	HP	3.5	G/KW-H		USE OF ULTRA LOW SULFUR DIESEL AND GOOD COMBUSTION PRACTICES
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Carbon Monoxide	1.66	MMBTU/H	2.6	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG. TIME	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Carbon Monoxide	500	H/YR	3.7	G/HP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Carbon Monoxide	300	HP	2.6	G/BPH-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Carbon Monoxide	300	HP	2.6	G/BHP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Carbon Monoxide	399	BHP	3.5	G/KW-H	HOURLY	State of the art combustion design.
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Carbon Monoxide	2.5	MMBTU/H	2.6	G/HP-H	HOURLY	Good combustion practices.
MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Carbon Monoxide	1.66	MMBTU/H	2.6	G/BHP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Carbon Monoxide	2.5	MMBTU/H	2.6	G/HP-H	HOURLY	Good combustion practices
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Carbon Monoxide	300	HP	2.6	G/B-HP-H	HOURLY	Good combustion practices and meeting NSPS Subpart IIII requirements
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Carbon Monoxide	300	HP	2.6	G/B-HP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Carbon Monoxide	2.5	MMBTU/H	2.6	G/HP-H	HOURLY	Good combustion practices.
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Carbon Monoxide	100	H/YR	1.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Carbon Monoxide	0	100 H/YR	11.6	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation (<= 100 H/YR)
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Carbon Monoxide	100	H/YR	1.87	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Carbon Monoxide	460	hp	0.53	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Carbon Monoxide	140	HP	1.15	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Carbon Monoxide	311	HP	1.79	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Carbon Monoxide	460	HP	2.6	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Carbon Monoxide	300	HP	1.73	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Carbon Monoxide	300	HP	1.73	LB/H		state of the art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Carbon Monoxide	410	HP	2.36	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual.
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Carbon Monoxide	250	HP	1.4	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Carbon Monoxide	320	HP	1.83	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Carbon Monoxide	402	HP	2.31	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturerâ€™s operating manual
OH-0383	PETMIN USA INCORPORATED	Black Start Generator (P007)	07/17/2020	Carbon Monoxide	158	HP	0.0644	T/YR		Tier IV engine Good combustion practices
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Carbon Monoxide	275	HP	3.5	G/KW-H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Carbon Monoxide	225	HP	1.29	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Carbon Monoxide	125	HP	1.03	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Carbon Monoxide	100	HP	0.83	LB/H		Good combustion practices to meet Tier IV emissions

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Carbon Monoxide	15	gal/hr	0.5	GM/HP-HR		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Emergency Fire Pump Engine	09/02/2016	Carbon Monoxide	0		2.61	G/BHP-HR		
PA-0326	SHELL POLYMERS MONACA SITE	Emergency Generator Parking Garage	02/18/2021	Carbon Monoxide	0		0.5	G	HP-HR	The use of certified engines, design of engines to include turbocharger and an intercooler/aftercooler, good combustion practices and proper operation and maintenance including certification to applicable federal emission standards
PA-0326	SHELL POLYMERS MONACA SITE	Emergency GeneratorTelecom Hut & Tower	02/18/2021	Carbon Monoxide	0		0.5	G	HP-HR	The use of certified engines, design of engines to include turbocharger and an intercooler/aftercooler, good combustion practices and proper operation and maintenance including certification to applicable federal emission standards
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Carbon Monoxide	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0799	BEAUMONT TERMINAL	EMERGENCY ENGINES	06/08/2016	Carbon Monoxide	0		0.0068	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Carbon Monoxide	214	kW	3.58	G/KW	HR	Meets EPA Tier 4 requirements
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Carbon Monoxide	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)
TX-0889	SWEENY OLD OCEAN FACILITIES	Emergency Generator Engines	08/08/2020	Carbon Monoxide	0		100	HR/YR		Good combustion practices and limited hours of operation
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Carbon Monoxide	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.

Table D-5.2 Summary of CO BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Carbon Monoxide	500	HR/YR	2.6	G/HP HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Carbon Monoxide	500	HR/YR	2.6	G/HP-H		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.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Carbon Monoxide	500	HR/YR	2.6	G/HP-H		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Carbon Monoxide	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel, and operate <500 hr/yr
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Carbon Monoxide	1.27	mmBtu/hr	0			
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Carbon Monoxide	0.22	mmBTU/hr	5	G/KWH		Good Combustion Practices
WI-0291	GRAYMONT WESTERN LIME-EDEN	P04 Emergency Diesel Generator	01/28/2019	Carbon Monoxide	0.22	mmBTU/hr	5	G/KWH		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Monoxide	282	HP	2.6	G/HP-H		Operation limited to 500 hours/year and shall be operated and maintained according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Monoxide	282	HP	2.6	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Carbon Monoxide	290	HP	0.33	LB/H		Good combustion practices
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Carbon Monoxide	290	HP	0.33	LB/H		

Table D-5.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Volatile Organic Compounds (VOC)	490	hp	0.0025	LB/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Volatile Organic Compounds (VOC)	98	hp	0.0025	LB/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Volatile Organic Compounds (VOC)	102	hp	0.0025	LB/HP-H		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Volatile Organic Compounds (VOC)	2.7	MMBTU/H	0.36	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Volatile Organic Compounds (VOC)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year.
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Volatile Organic Compounds (VOC)	2.7	MMBtu/hr	0.36	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Volatile Organic Compounds (VOC)	14.6	Gal/hr	0.22	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Volatile Organic Compounds (VOC)	0		1.55	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Volatile Organic Compounds (VOC)	1073	bhp	1	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Volatile Organic Compounds (VOC)	0		0.13	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-5.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Volatile Organic Compounds (VOC)	0		1.12	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Volatile Organic Compounds (VOC)	369	hp	4	G/KW-HR	3-HR AVG	
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Volatile Organic Compounds (VOC)	0		0.05	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Volatile Organic Compounds (VOC)	150	hp	1.134	G/HP-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Volatile Organic Compounds (VOC)	250	hp	1.134	G/HP-HR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Volatile Organic Compounds (VOC)	500	Horsepower	1.13	G/HP-HR		certified engine
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Volatile Organic Compounds (VOC)	197	HP	1.14	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	260	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	440	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Volatile Organic Compounds (VOC)	61	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Volatile Organic Compounds (VOC)	288	hp (each)	0			Complying with 40 CFR 60 Subpart IIII

Table D-5.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Volatile Organic Compounds (VOC)	282	HP	1.87	LB/H	HOURLY MAXIMUM	Good combustion practices
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Volatile Organic Compounds (VOC)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Volatile Organic Compounds (VOC)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Volatile Organic Compounds (VOC)	460	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Volatile Organic Compounds (VOC)	375	HP	4	G/KW-H		Good combustion practices and NSPS Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Volatile Organic Compounds (VOC)	300	HP	4	G/KW-H		Good combustion practices and NSPS Subpart IIII
LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Volatile Organic Compounds (VOC)	0		4	G/KW-HR	NMEHC + NOX	Compliance with 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
LA-0366	HOLDEN WOOD PRODUCTS MILL	Fire Pump, Sawmill Emergency, and Planer Mill Emergency Generator Engines	02/03/2021	Volatile Organic Compounds (VOC)	0		804.6	HP		Good Combustion Practices and Compliance with NSPS 40 CFR 60 Subpart IIII
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Volatile Organic Compounds (VOC)	300	hp	0.19	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII.
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0387	TAYLOR SAWMILL	Firewater Pump Engine (FIR)	04/12/2022	Volatile Organic Compounds (VOC)	274	horsepower	0.02	TPY		Compliance with 40 CFR 60 Subpart IIII
LA-0390	DERIDDER SAWMILL	ENG1 - Emergency Fire Water Pump	05/10/2022	Volatile Organic Compounds (VOC)	500	horsepower	1.85	LB/HR		Good combustion practices and maintenance and compliance with applicable 40 CFR 60 Subpart JJJJ limitation for VOC.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Volatile Organic Compounds (VOC)	355	hp	3	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.

Table D-5.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Volatile Organic Compounds (VOC)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Volatile Organic Compounds (VOC)	422	horsepower	1.47	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Volatile Organic Compounds (VOC)	422	horsepower	1.47	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Volatile Organic Compounds (VOC)	237	horsepower	0.61	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Volatile Organic Compounds (VOC)	200	horsepower	0.14	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Volatile Organic Compounds (VOC)	1.66	MMBTU/H	0.64	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Volatile Organic Compounds (VOC)	500	H/YR	0.47	LB/H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good combustion practices
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Volatile Organic Compounds (VOC)	399	BHP	0.13	LB/H	HOURLY	State of the art combustion design.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good combustion practices.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Volatile Organic Compounds (VOC)	300	HP	0.75	LB/H	HOURLY	Good Combustion Practices
NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 2	11/21/2022	Volatile Organic Compounds (VOC)	510	hp	0.62	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Volatile Organic Compounds (VOC)	140	HP	0.11	LB/H		State-of-the-art combustion design

Table D-5.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Volatile Organic Compounds (VOC)	311	HP	0.25	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Volatile Organic Compounds (VOC)	460	HP	0.14	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Volatile Organic Compounds (VOC)	300	HP	0.24	LB/H		State-of-the-art combustion design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Volatile Organic Compounds (VOC)	300	HP	0.24	LB/H		State-of-the-art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Volatile Organic Compounds (VOC)	410	HP	2.7	LB/H	NMHC+NOX. SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual.
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Volatile Organic Compounds (VOC)	320	HP	2.12	LB/H	NMHC+NOX. SEE NOTES.	Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Volatile Organic Compounds (VOC)	402	HP	2.64	LB/H	SEE NOTES.	Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Volatile Organic Compounds (VOC)	275	HP	0.7	LB/H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OK-0164	MIDWEST CITY AIR DEPOT	Diesel-Fueled Fire Pump Engines	01/08/2015	Volatile Organic Compounds (VOC)	300	HP	0.15	GRAMS PER HP-HR	TOTAL FOR 3 ENGINES.	1. Good Combustion Practices.
OK-0175	WILDHORSE TERMINAL	Emergency Use Engine less than or equal to 500 HP	06/29/2017	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good combustion practices, certified to meet EPA Tier 3 engine standards. Gen-1, FP-1, and FP-2 shall be limited to operate no more than 500 hr/yr.
OK-0176	BPV GATHERING AND MARKETING CUSHING STATION	Emergency Generator	07/19/2017	Volatile Organic Compounds (VOC)	400	HP	217.24	TONS/YEAR/FACILITY	12-MONTH	Equipped with non-resettable hour meter. Fired with ultra-low sulfur diesel fuel (0.015 % or less by wt. sulfur.

Table D-5.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OK-0177	CUSHING SOUTH TANK FARM	Emergency use engine & or = 500 hp	01/04/2018	Volatile Organic Compounds (VOC)	0		1	GM/HP-HR		Good combustion practices, certified to meet EPA Tier III engine standards. Limited to operate no more than 500 hr/yr.
OK-0181	WILDHORSE TERMINAL	EMERGENCY USE ENGINES & 500 HP	09/11/2019	Volatile Organic Compounds (VOC)	0		3	GM/HP-HR		Good Combustion Practices. Certified to meet EPA Tier 3 engine standards. Gen-1 and FP-1 shall be limited to operate not more than 500 hours per year. SP-1 shall be limited to operate not more than 876 hours per year.
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Volatile Organic Compounds (VOC)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0799	BEAUMONT TERMINAL	EMERGENCY ENGINES	06/08/2016	Volatile Organic Compounds (VOC)	0		0.0025	LB/HP-HR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Volatile Organic Compounds (VOC)	214	kW	0.19	G/KW	HR	Meets EPA Tier 4 requirements
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Volatile Organic Compounds (VOC)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Volatile Organic Compounds (VOC)	500	HR/YR	0			good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Volatile Organic Compounds (VOC)	500	HR/YR	0.11	G/HP-HR		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.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Volatile Organic Compounds (VOC)	500	HR/YR	0.11	G/HP-HR		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Volatile Organic Compounds (VOC)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel, and operate <500 hr/yr

Table D-5.3 Sumamry of VOC BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Volatile Organic Compounds (VOC)	1.27	mmBtu/hr	0			
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	EG8 â€“ Diesel Emergency Generator	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Complying with NSPS Standards under 40 CFR Part 60 Subpart IIII
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	EG8 Diesel Emergency Generator	10/02/2017	Volatile Organic Compounds (VOC)	0		0			
WI-0292	GREEN BAY PACKAGING INC. â€“MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Volatile Organic Compounds (VOC)	0		200	HOURS	12-MONTH PERIOD	Hours of Operation
WI-0292	GREEN BAY PACKAGING INC. MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Volatile Organic Compounds (VOC)	0		200	HOURS	12-MONTH PERIOD	
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Volatile Organic Compounds (VOC)	282	HP	1.1	G/HP-H		Operation limited to 500 hours/year and operate and maintain according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Volatile Organic Compounds (VOC)	282	HP	1.1	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Volatile Organic Compounds (VOC)	290	HP	0.26	LB/H		Good combustion practices
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Volatile Organic Compounds (VOC)	290	HP	0.26	LB/H		

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Particulate matter, filterable (FPM)	300	HP	0.15	G/B-HP-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Particulate matter, filterable (FPM)	300	HP	0.15	G/B-HP-H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
*LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Particulate matter, filterable (FPM2.5)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Particulate matter, filterable (FPM)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Particulate matter, filterable (FPM)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Particulate matter, filterable (FPM)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Particulate matter, filterable (FPM2.5)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Particulate matter, filterable (FPM)	350	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Particulate matter, filterable (FPM10)	0		0.2	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII
*LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Particulate matter, filterable (FPM2.5)	0		0.2	G/KW-HR		Compliance with 40 CFR 60 Subpart IIII
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	260	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	440	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Particulate matter, filterable (FPM)	61	HP	0.3	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
*LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Particulate matter, filterable (FPM10)	0		0			Comply with standards of 40 CFR 60 Subpart IIII, limit operation to <= 100 hrs/yr
*MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Particulate matter, filterable (FPM)	1.66	MMBTU/H	0.15	G/BHP-H	HOURLY	Good Combustion Practices and meeting NSPS Subpart IIII requirements
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, filterable (FPM)	500	HR/YR	0.15	G/HP-HR		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.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, filterable (FPM)	500	HR/YR	0.15	G/HP-HR		
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Particulate matter, filterable (FPM)	1073	bhp	0.25	G/KW-HR		Good operating practices.
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Particulate matter, filterable (FPM10)	158	HP	5.22	X10-3 LB/H		Tier IV engine Good combustion practices
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Particulate matter, filterable (FPM2.5)	158	HP	5.22	X10-3 LB/H		Tier IV engine Good combustion practices
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	07/27/2018	Particulate matter, filterable (FPM)	8700	gal/year	0.2	G/KW-HOUR		Operate and maintain the engine according to the manufacturer's written instructions
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Particulate matter, filterable (FPM)	399	BHP	0.2	G/KW-H	HOURLY	State of the art combustion design

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Particulate matter, filterable (FPM)	300	HP	0.15	G/BHP-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Particulate matter, filterable (FPM)	300	HP	0.15	G/BHP-H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Particulate matter, filterable (FPM)	500	HR/YR	15	G/HP/HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM)	150	hp	1.34	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM10)	150	hp	1.34	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM)	250	hp	0.54	G/KW-HR		
IN-0295	STEEL DYNAMICS, INC. - ENGINEERED BAR PRODUCTS DIVISION	Emergency Diesel Generators	02/23/2018	Particulate matter, filterable (FPM10)	250	hp	1.34	G/KW-HR		
FL-0363	DANIA BEACH ENERGY CENTER	Emergency Fire Pump Engine (422 hp)	12/04/2017	Particulate matter, filterable (FPM)	0		0.2	G / KWH		Certified engine
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Particulate matter, filterable (FPM)	1.66	MMBTU/H	0.15	G/BHP-H	TEST PROTOCOL WILL SPECIFY AVG TIME.	Good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Particulate matter, filterable (FPM)	500	H/YR	0.22	G/HP-H	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Particulate matter, filterable (FPM10)	282	HP	0.09	LB/H	HOURLY MAXIMUM	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).
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Particulate matter, filterable (FPM2.5)	282	HP	0.09	LB/H	HOURLY MAXIMUM	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).

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Particulate matter, filterable (FPM)	0	100 H/YR	0.661	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Particulate matter, filterable (FPM)	100	H/YR	0.108	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
MO-0089	OWENS CORNING INSULATION SYSTEMS, LLC	emergency engines	05/12/2016	Particulate matter, filterable (FPM)	0		0	G/KW		good operating practices
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Particulate matter, filterable (FPM)	100	H/YR	0.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Particulate matter, filterable (FPM)	460	hp	0.087	G/BHP-H	1 H	Compliance demonstrated with vendor emission certification and adherence to vendor-specified maintenance recommendations.
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Particulate matter, filterable (FPM)	15	gal/hr	0.11	GM/HP-HR		
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Particulate matter, filterable (FPM)	0		0.16	G/HP-H		GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Particulate matter, filterable (FPM)	1490	HP	0.2	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Particulate matter, filterable (FPM)	305	HP	0.2	G/KW-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Particulate matter, filterable (FPM10)	490	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Particulate matter, filterable (FPM2.5)	490	hp	0.15	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Particulate matter, filterable (FPM10)	98	hp	0.3	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Particulate matter, filterable (FPM2.5)	98	hp	0.3	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Particulate matter, filterable(FPM10)	102	hp	0.22	GRAMS/HP-H		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Particulate matter, filterable (FPM2.5)	102	hp	0.22	GRAMS/HP-H		

Table D-5.4 Summary of Filterable PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Particulate matter, filterable (FPM2.5)	251	HP	0			
WV-0025	MOUNDSVILLE COMBINED CYCLE POWER PLANT	Fire Pump Engine	11/21/2014	Particulate matter, filterable (FPM2.5)	251	HP	0			

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Particulate matter, total (TPM10)	2.7	MMBTU/H	0.31	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Particulate matter, total (TPM)	2.7	MMBTU/H	0.31	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Particulate matter, total (TPM2.5)	2.7	MMBTU/H	0.31	LB/MMBTU		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM)	252	hp	0.19	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM10)	252	hp	0.19	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Particulate matter, total (TPM2.5)	252	hp	0.19	G/KW-HR	3-HOUR AVERAGE	Clean Fuel and Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Particulate matter, total (TPM)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year per engine
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Particulate matter, total (TPM10)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year per engine
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Particulate matter, total (TPM2.5)	19.4	gph	0.19	G/HP-HR	3-HOUR AVERAGE	Good combustion practices, ULSD, and limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Particulate matter, total (TPM)	2.7	MMBtu/hr	0.31	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Particulate matter, total (TPM10)	2.7	MMBtu/hr	0.31	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Particulate matter, total (TPM2.5)	2.7	MMBtu/hr	0.31	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Particulate matter, total (TPM)	14.6	Gal/hr	0.022	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Particulate matter, total (TPM10)	14.6	Gal/hr	0.022	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Particulate matter, total (TPM2.5)	14.6	Gal/hr	0.022	G/HP-HR		Good Combustion Practices; Limited Operation; 40 CFR 60 Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Particulate matter, total (TPM)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Particulate matter, total (TPM10)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0168	BIG RIVER STEEL LLC	Emergency Engines	03/17/2021	Particulate matter, total (TPM2.5)	0		0.2	G/KW-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Particulate matter, total (TPM10)	1073	bhp	0.2	G/KW-HR		Good operating practices.
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Particulate matter, total (TPM2.5)	1073	bhp	0.2	G/KW-HR		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Particulate matter, total (TPM10)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Particulate matter, total < 2.5 Âµ (TPM2.5)	0		0.1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Particulate matter, total (TPM10)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Particulate matter, total (TPM2.5)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Particulate matter, total (TPM)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Particulate matter, total (TPM10)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Particulate matter, total (TPM2.5)	0		1	G/BHP-HR		Good Operating Practices, limited hours of operation, Compliance with NSPS Subpart IIII
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Particulate matter, total (TPM)	29	MMBTU/H	0.2	G / KWH		Low-emitting fuel and certified engine
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	One 422-hp emergency fire pump engine	03/09/2016	Particulate matter, total (TPM)	0		0.2	G / KW-HR		Use of clean fuel
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Emergency Fire Pump Engine (347 HP)	06/07/2021	Particulate matter, total (TPM)	2.46	MMBtu/hour	0.2	G/KW-HOUR		
IL-0129	CPV THREE RIVERS ENERGY CENTER	Firewater Pump Engine	07/30/2018	Particulate matter, total (TPM)	0		0			
IL-0130	JACKSON ENERGY CENTER	Firewater Pump Engine	12/31/2018	Particulate matter, total (TPM)	420	horsepower	0.2	G/KW-HR		
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Particulate matter, total (TPM)	320	horsepower	0.2	GRAMS	KILOWATT-HOUR	
IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Particulate matter, total (TPM10)	369	hp	0.2	G/KW-HR	3-HR AVG	
IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Particulate matter, total (TPM2.5)	369	hp	0.2	G/KW-HR	3-HR AVG	
IN-0234	GRAIN PROCESSING CORPORATION	EMERGENCY FIRE PUMP ENGINE	12/08/2015	Particulate matter, total (TPM10)	0		0.16	G/HP-H		GOOD COMBUSTION PRACTICES
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Particulate matter, total (TPM)	500	Horsepower	0.15	G/HP-H		certified engine
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Particulate matter, total (TPM10)	500	Horsepower	0.15	G/HP-H		certified engine
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Particulate matter, total (TPM2.5)	500	Horsepower	0.15	G/HP-H		certified engine
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Particulate matter, total (TPM2.5)	750	KW	0.15	G PER BHP-HR		Low sulfur fuel oil (<15 ppm sulfur)
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Particulate matter, total (TPM10)	750	KW	0.15	G PER BHP-HR		Low sulfur fuel oil (<15 ppm sulfur)
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Particulate matter, total (TPM)	750	KW	0.15	G PER BHP-HR		Low sulfur fuel oil (<15 ppm sulfur)
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Particulate matter, total (TPM)	197	HP	0.15	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Particulate matter, total (TPM10)	197	HP	0.15	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KS-0030	MID-KANSAS ELECTRIC COMPANY, LLC - RUBART STATION	Compression ignition RICE emergency fire pump	03/31/2016	Particulate matter, total (TPM2.5)	197	HP	0.15	G/HP-HR	EXCLUDES STARTUP, SHUTDOWN & MALFUNCTION	
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	260	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	260	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	440	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	440	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	190	HP	0.15	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Particulate matter, total (TPM10)	61	HP	0.3	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Particulate matter, total (TPM2.5)	61	HP	0.3	G/HP-HR		This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Particulate matter, total (TPM10)	350	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	04/19/2021	Particulate matter, total (TPM2.5)	350	HP	0.15	G/HP-HR		The permittee must develop a Good Combustion and Operating Practices (GCOP) Plan
LA-0306	TOPCHEM POLLOCK, LLC	Genenerator Engine DEG-16-1 (EQT035)	12/20/2016	Particulate matter, total (TPM2.5)	460	horsepower	0.18	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0306	TOPCHEM POLLOCK, LLC	Pump Engines DFP-16-1 (EQT036)	12/20/2016	Particulate matter, total (TPM2.5)	225	horsepower	0.09	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0306	TOPCHEM POLLOCK, LLC	Pump Engine DFP-16-2 (EQT037)	12/20/2016	Particulate matter, total (TPM2.5)	225	horsepower	0.09	LB/H	HOURLY MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Particulate matter, total (TPM10)	288	hp (each)	0.15	G/BHP-HR		Complying with 40 CFR 60 Subpart IIII
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Particulate matter, total (TPM2.5)	288	hp (each)	0.15	G/BHP-HR		Complying with 40 CFR 60 Subpart IIII
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Particulate matter, total (TPM10)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Particulate matter, total (TPM2.5)	425	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Particulate matter, total (TPM10)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Particulate matter, total (TPM2.5)	350	hp	0			complying with 40 CFR 63 subpart ZZZZ
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Particulate matter, total (TPM10)	460	hp	0			Complying with 40 CFR 60 Subpart IIII
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Particulate matter, total (TPM2.5)	460	hp	0			Complying with 40 CFR 60 Subpart IIII

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Particulate matter, total (TPM10)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Particulate matter, total (TPM2.5)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Particulate matter, total (TPM10)	375	HP	0.2			Compliance with 40 CFR 60 Subpart IIII.
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Particulate matter, total (TPM2.5)	375	HP	0.2			Compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Particulate matter, total (TPM10)	300	HP	0.2			Compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Particulate matter, total (TPM2.5)	300	HP	0.2			Compliance with 40 CFR 60 Subpart III
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Particulate matter, total (TPM10)	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0345	DIRECT REDUCED IRON FACILITY	IC engines (14 units)	06/13/2019	Particulate matter, total (TPM2.5)	0		0			Comply with requirements of 40 CFR 60 Subpart IIII
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
LA-0349	DRIFTWOOD LNG FACILITY	IC Engines (18)	07/10/2018	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII and Good Combustion Practices
LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Particulate matter, total (TPM2.5)	1.1	MM BTU/hr	0.04	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Particulate matter, total (TPM10)	1.1	MM BTU/hr	0.04	LB/HR	HOURLY MAXIMUM	The use of low sulfur fuels and compliance with 40 CFR 60 Subpart IIII
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Particulate matter, total (TPM)	450	hp	0.4	G//HP-HR		Good combustion practices/gaseous fuel burning
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment A	05/04/2021	Particulate matter, total (TPM10)	450	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Particulate matter, total (TPM)	439	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Generator B	05/04/2021	Particulate matter, total (TPM10)	439	hp	0.4	G/HP-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Particulate matter, total (TPM)	180	hp	0.2	G/KW-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	VCM Unit Emergency Cooling Water Pumps	05/04/2021	Particulate matter, total (TPM10)	180	hp	0.2	G/KW-HR		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Particulate matter, total (TPM)	375	hp	0.31	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment B	05/04/2021	Particulate matter, total (TPM10)	375	hp	0.31	LB/MM BTU		Good combustion practices/gaseous fuel burning.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Particulate matter, total (TPM10)	300	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	PVC Emergency Combustion Equipment 2A and 2B	05/04/2021	Particulate matter, total (TPM2.5)	300	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII.
LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Particulate matter, total (TPM2.5)	0		0			Comply with standards of 40 CFR 60 Subpart IIII Limit operation to <= 100 hrs/yr
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Particulate matter, total (TPM10)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Particulate matter, total (TPM2.5)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Particulate matter, total (TPM10)	355	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII standards, good combustion practices, and the use of ultra-low sulfur diesel fuel.

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Particulate matter, total (TPM2.5)	355	hp	0.15	G/HP-HR		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
LA-0397	WESTLAKE ETHYLENE PLANT	Emergency Generators and Fire Water Pumps (EQT0027 - EQT0032, EQT0044, EQT0045)	04/29/2022	Particulate matter, total (TPM10)	0		0			Compliance with applicable requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Particulate matter, total (TPM2.5)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-01 - Firewater Pump Engine No. 1	12/20/2023	Particulate matter, total (TPM10)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Particulate matter, total (TPM2.5)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-02 - Firewater Pump Engine No. 2	12/20/2023	Particulate matter, total (TPM10)	422	horsepower	0.2	LB/HR		Compliance with 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Particulate matter, total (TPM2.5)	237	horsepower	0.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0401	KOCH METHANOL (KME) FACILITY	FWP-03 - Firewater Pump Engine No. 3	12/20/2023	Particulate matter, total (TPM10)	237	horsepower	0.06	LB/HR		Compliance with the requirements of 40 CFR 60 Subpart IIII
LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Particulate matter, total (TPM10)	200	horsepower	0.14	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII
LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Particulate matter, total (TPM2.5)	200	horsepower	0.14	LB/H	HOURLY MAXIMUM	Compliance with 40 CFR 60 Subpart IIII
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Particulate matter, total (TPM10)	1490	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Particulate matter, total (TPM2.5)	1490	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AN DGOOD COMBUSTION PRACTICES
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Particulate matter, total (TPM10)	305	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Particulate matter, total (TPM2.5)	305	HP	0.18	G/HP-H		EXCLUSIVE USE OF ULTRA LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Particulate matter, total (TPM10)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Particulate matter, total (TPM2.5)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Particulate matter, total (TPM10)	500	H/YR	0.09	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Particulate matter, total (TPM2.5)	500	H/YR	0.09	LB/MMBTU	TEST PROTOCOL WILL SPECIFY AVG TIME	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Particulate matter, total (TPM10)	399	BHP	0.13	LB/H	HOURLY	State of the art combustion design.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Particulate matter, total (TPM2.5)	399	BHP	0.13	LB/H	HOURLY	State of the art combustion design.
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM10)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Particulate matter, total (TPM2.5)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Particulate matter, total (TPM10)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices
MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Particulate matter, total (TPM2.5)	1.66	MMBTU/H	0.57	LB/H	HOURLY	Good combustion practices

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Particulate matter, total (TPM10)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Particulate matter, total (TPM2.5)	2.5	MMBTU/H	0.12	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, good combustion practices and meeting NSPS Subpart IIII requirements.
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Particulate matter, total (TPM10)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Particulate matter, total (TPM2.5)	300	HP	0.66	LB/H	HOURLY	Diesel particulate filter, Good Combustion Practices and meeting NSPS Subpart IIII requirements
MI-0453	GENERAL MOTORS LLC ORION ASSEMBLY	FGEMENGINES	09/27/2022	Particulate matter, total (TPM10)	500	h/yr	0.15	G/B-HP-H	HOURLY (EACH INDIVIDUAL EMISSION UNIT)	Hours of Operation Restriction, Good Combustion Practices, Compliance with NSPS
MI-0453	GENERAL MOTORS LLC ORION ASSEMBLY	FGEMENGINES	09/27/2022	Particulate matter, total (TPM2.5)	500	h/yr	0.15	G/B-HP-H	HOURLY (EACH INDIVIDUAL EMISSION UNIT)	Hours of Operation Restriction, Good Combustion Practices, Compliance with NSPS
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Particulate matter, total (TPM10)	2.5	MMBTU/H	0.69	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Particulate matter, total (TPM2.5)	2.5	MMBTU/H	0.69	LB/H	HOURLY	Ultra low sulfur diesel fuel and good combustion practices.
NE-0064	NORFOLK CRUSH, LLC	Emergency Fire Water Pump Engine 2	11/21/2022	Particulate matter, total (TPM)	510	hp	0.15	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE	
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Particulate matter, total (TPM10)	100	H/YR	0.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation
NJ-0084	PSEG FOSSIL LLC SEWAREN GENERATING STATION	Emergency Diesel Fire Pump	03/10/2016	Particulate matter, total (TPM2.5)	100	H/YR	0.1	LB/H		use of ULSD a clean burning fuel, and limited hours of operation

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Particulate matter, total (TPM10)	0	100 H/YR	0.661	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY GENERATOR DIESEL	07/19/2016	Particulate matter, total (TPM2.5)	0	100 H/YR	0.661	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Particulate matter, total (TPM10)	100	H/YR	0.108	LB/H		Use of Ultra Low Sulfur Diesel (ULSD) Oil a clean burning fuel and limited hours of operation
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	EMERGENCY DIESEL FIRE PUMP	07/19/2016	Particulate matter, total (TPM2.5)	100	H/YR	0.108	LB/H		Use of ULSD a clean burning fuel and limited hours of operation
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Particulate matter, total (TPM10)	140	HP	0.07	LB/H		State-of-the-art combustion design
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Particulate matter, total (TPM2.5)	140	HP	0.07	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Particulate matter, total (TPM10)	311	HP	0.1	LB/H		State-of-the-art combustion design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Particulate matter, total (TPM2.5)	311	HP	0.1	LB/H		State-of-the-art combustion design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Particulate matter, total (TPM10)	460	HP	0.02	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Particulate matter, total (TPM2.5)	460	HP	0.02	LB/H		good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Particulate matter, total (TPM10)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Particulate matter, total (TPM2.5)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Particulate matter, total (TPM10)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Particulate matter, total (TPM2.5)	300	HP	0.1	LB/H		Ultra low sulfur diesel fuel

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Particulate matter, total (TPM)	410	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturerâ€™s operating manual.
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Particulate matter, total (TPM2.5)	410	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturerâ€™s operating manual.
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Particulate matter, total (TPM10)	250	HP	0.1	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Particulate matter, total (TPM2.5)	250	HP	0.1	LB/H		Comply with NSPS 40 CFR 60 Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Particulate matter, total (TPM)	320	HP	0.11	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Particulate matter, total (TPM10)	320	HP	0.11	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Particulate matter, total (TPM2.5)	320	HP	0.11	LB/H		Good combustion practices (ULSD) and compliance with 40 CFR Part 60, Subpart IIII
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Particulate matter, total (TPM)	402	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturerâ€™s operating manual
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Particulate matter, total (TPM10)	402	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Particulate matter, total (TPM2.5)	402	HP	0.13	LB/H		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII and employ good combustion practices per the manufacturer's operating manual
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Particulate matter, total (TPM)	275	HP	0.2	G/KW-H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Particulate matter, total (TPM10)	275	HP	0.6	LB/H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0387	INTEL OHIO SITE	275 hp (205 kW) Diesel-Fired Emergency Fire Pump Engine	09/20/2022	Particulate matter, total (TPM2.5)	275	HP	0.6	LB/H		Certified to meet the standards in Table 4 of 40 CFR Part 60, Subpart IIII and good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Particulate matter, total (TPM10)	225	HP	0.02	LB/H	SEE NOTES	Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Particulate matter, total (TPM2.5)	225	HP	0.02	LB/H	SEE NOTES	Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Particulate matter, total (TPM10)	125	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Particulate matter, total (TPM2.5)	125	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Particulate matter, total (TPM10)	100	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Particulate matter, total (TPM2.5)	100	HP	0.01	LB/H		Good combustion practices to meet Tier IV emissions
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Particulate matter, total (TPM10)	15	gal/hr	0.11	GM/HP-HR		
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Particulate matter, total (TPM2.5)	15	gal/hr	0.11	GM/HP-HR		
PA-0310	CPV FAIRVIEW ENERGY CENTER	Emergency Fire Pump Engine	09/02/2016	Particulate matter, total (TPM)	0		0.15	G/BHP-HR		

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Particulate matter, total (TPM)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Particulate matter, total (TPM10)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Particulate matter, total (TPM2.5)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Particulate matter, total (TPM10)	214	kW	0.02	G/KW	HR	Meets EPA Tier 4 requirements
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Particulate matter, total (TPM2.5)	214	kW	0.02	G/KW	HR	Meets EPA Tier 4 requirements
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Particulate matter, total (TPM)	0		0			Tier 4 exhaust emission standards specified at 40 CFR Â§ 1039.101(b)
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Particulate matter, total (TPM10)	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Particulate matter, total (TPM2.5)	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Particulate matter, total (TPM10)	500	HR/YR	0.15	G/HP HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Particulate matter, total (TPM2.5)	500	HR/YR	0.15	G/HP HR		good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM2.5)	500	HR/YR	0.15	G/HP-HR		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.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM10)	500	HR/YR	0.15	G/HP-HR		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.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM2.5)	500	HR/YR	0.15	G/HP-HR		
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Particulate matter, total (TPM10)	500	HR/YR	0.15	G/HP-HR		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel with sulfur content < 15 ppm, and operate <500 hr/yr
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM10)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel with sulfur content < 15 ppm, and operate <500 hr/yr
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM2.5)	1.27	mmBtu/hr	0			Good combustion practices, use diesel fuel with sulfur content < 15 ppm, and operate <500 hr/yr
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM)	1.27	mmBtu/hr	0			
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM10)	1.27	mmBtu/hr	0			
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Particulate matter, total (TPM2.5)	1.27	mmBtu/hr	0			
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM)	0		0.29	LB/HR		BACT is the use of ultra-low sulfur distillate in the generator. Compliance with this requirement will be determined using sulfur content testing for all shipments of fuel received.

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM10)	0		0.29	;B/HR		BACT is the use of ultra-low sulfur distillate in the generator. Compliance with this requirement will be determined using sulfur content testing for all shipments of fuel received.
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM2.5)	0		0.29	LB/HR		BACT is the use of ultra-low sulfur distillate in the generator. Compliance with this requirement will be determined using sulfur content testing for all shipments of fuel received.
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM)	0		0.29	LB/HR		
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM10)	0		0.29	LB/HR		
WI-0271	KOHLER CO-METALS PROCESSING COMPLEX	P10K Diesel Powered Emergency Generator	06/05/2015	Particulate matter, total (TPM2.5)	0		0.29	LB/HR		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM)	282	HP	0.15	G/HP-H		Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm, and shall be operated and maintained according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM10)	282	HP	0.15	G/HP-H		Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm, and operate and maintain according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM2.5)	282	HP	0.15	G/HP-H		Operation limited to 500 hours/year, sulfur content of diesel fuel oil fired may not exceed 15 ppm, and shall be operated and maintained according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM)	282	HP	0.15	G/HP-H		

Table D-5.5 Summary for Total PM10/PM2.5 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM10)	282	HP	0.15	G/HP-H		
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Particulate matter, total (TPM2.5)	282	HP	0.15	G/HP-H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM10)	290	HP	0.11	LB/H		Good combustion practices, use diesel fuel oil with sulfur content of no greater than 0.0015% by weight.
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM)	290	HP	0.11	LB/H		Good combustion practices, use diesel fuel oil with sulfur content of no greater than 0.0015% by weight
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM10)	290	HP	0.11	LB/H		
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Particulate matter, total (TPM)	290	HP	0.11	LB/H		

Table D-5.6 Summary of H_2SO_4 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0354	LAUDERDALE PLANT	Emergency fire pump engine, 300 HP	08/25/2015	Sulfuric Acid (mist, vapors, etc)	29	MMBTU/H	0.0015	% S IN ULSD	FUEL RECORD KEEPING	Limit in S in fuel
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Sulfuric Acid (mist, vapors, etc)	320	horsepower	0			Use of ultra-low sulfur diesel, with a sulfur content < 15 ppm sulfur.
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY GENERATOR	11/13/2015	Sulfuric Acid (mist, vapors, etc)	1490	HP	0.007	G/HP-H	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION
MD-0045	MATTAWOMAN ENERGY CENTER	EMERGENCY DIESEL ENGINE FOR FIRE WATER PUMP	11/13/2015	Sulfuric Acid (mist, vapors, etc)	305	HP	0.007	G/HP-H	3-HOUR BLOCK AVERAGE	EXCLUSIVE USE OF ULSD FUEL, GOOD COMBUSTION PRACTICES, AND LIMITING THE HOURS OF OPERATION
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Sulfuric Acid (mist, vapors, etc)	399	BHP	15	PPM	FUEL SUPPLIER RECORDS OR TEST DATA	Good combustion practices, low sulfur fuel.
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Sulfuric Acid (mist, vapors, etc)	460	hp	0.0001	LB/MMBTU	1 H	Ultra low sulfur diesel with maximum sulfur content 0.0015 percent.
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Sulfuric Acid (mist, vapors, etc)	140	HP	3	X10-5 LB/H		Low sulfur fuel
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Sulfuric Acid (mist, vapors, etc)	311	HP	6.7	X10-5 LB/H		Ultra low sulfur diesel fuel
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Sulfuric Acid (mist, vapors, etc)	300	HP	6.5	X10-5 LB/H		Ultra low sulfur diesel fuel
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Sulfuric Acid (mist, vapors, etc)	300	HP	6.5	X10-5 LB/H		Ultra low sulfur diesel fuel
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Sulfuric Acid (mist, vapors, etc)	410	HP	0.0015	LB/MMBTU		Certified to the meet the emissions standards in Table 4 of 40 CFR Part 60, Subpart IIII. Good combustion practices per the manufacturer's operating manual.
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Sulfuric Acid (mist, vapors, etc)	320	HP	7.3	X10-4 LB/MMBTU		ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than 15 ppm (0.0015 percent by weight)
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Sulfuric Acid (mist, vapors, etc)	15	gal/hr	0.0006	G/HP-HR		

Table D-5.6 Summary of H_2SO_4 BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0			good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0			
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0.0001	LB/MMBTU		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.
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Sulfuric Acid (mist, vapors, etc)	500	HR/YR	0.0001	LB/MMBTU		
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Sulfuric Acid (mist, vapors, etc)	1.27	mmBtu/hr	0			Use diesel fuel with sulfur content < 15 ppm
WI-0263	WISCONSIN POWER & LIGHT - NEENAH GENERATING STATION	Fire pump (process P05)	02/15/2016	Sulfuric Acid (mist, vapors, etc)	1.27	mmBtu/hr	0			
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	282	HP	0			Operation limited to 500 hours/year, operate and maintain according to the manufacturers recommendations, and sulfur content of the diesel fuel oil fired may not exceed 15 ppm.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Sulfuric Acid (mist, vapors, etc)	282	HP	0			
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Sulfuric Acid (mist, vapors, etc)	290	HP	0			Only use diesel fuel oil with a sulfur content of no greater than 0.015% by weight
WI-0302	WPL- RIVERSIDE ENERGY CENTER	Diesel-Fired Fire Pump Engine (P04)	02/28/2020	Sulfuric Acid (mist, vapors, etc)	290	HP	0			

Table D-5.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0082	POINT THOMSON PRODUCTION FACILITY	Airstrip Generator Engine	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	490	hp	163	TONS/YEAR		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Agitator Generator Engine	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	98	hp	356	TONS/YEAR		
AK-0082	POINT THOMSON PRODUCTION FACILITY	Incinerator Generator Engine	01/23/2015	Carbon Dioxide Equivalent (CO_2e)	102	hp	516	TONS/YEAR		
AK-0083	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	01/06/2015	Carbon Dioxide Equivalent (CO_2e)	2.7	MMBTU/H	37.2	TONS/YEAR		Limited Operation of 168 hr/yr.
AK-0084	DONLIN GOLD PROJECT	Fire Pump Diesel Internal Combustion Engines	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	252	hp	216	TPY (COMBINED)	YEARLY	Good Combustion Practices
AK-0085	GAS TREATMENT PLANT	Three (3) Firewater Pump Engines and two (2) Emergency Diesel Generators	08/13/2020	Carbon Dioxide Equivalent (CO_2e)	19.4	gph	163.6	LB/MMBTU	3-HOUR AVERAGE	Good combustion practices and limit operation to 500 hours per year per engine
AK-0086	KENAI NITROGEN OPERATIONS	Diesel Fired Well Pump	03/26/2021	Carbon Dioxide Equivalent (CO_2e)	2.7	MMBtu/hr	164	LB/MMBTU	THREE-HOUR AVERAGE	Good Combustion Practices and Limited Use
AK-0088	LIQUEFACTION PLANT	Auxiliary Air Compressor Engine	07/07/2022	Carbon Dioxide Equivalent (CO_2e)	14.6	Gal/hr	163.6	LB/MMBTU	3-HOURS	Good Combustion Practices; Limited Operation
AR-0171	NUCOR STEEL ARKANSAS	SN-106 Cold Mill 1 Diesel Fired Emergency Generator	02/14/2019	Carbon Dioxide Equivalent (CO_2e)	1073	bhp	163	LB/MMBTU		Good operating practices.
AR-0173	BIG RIVER STEEL LLC	Emergency Engines	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good Operating Practices
AR-0173	BIG RIVER STEEL LLC	Emergency Water Pumps	01/31/2022	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good Operating Practices
AR-0180	HYBAR LLC	Emergency Water Pumps	04/28/2023	Carbon Dioxide Equivalent (CO_2e)	0		164	LB/MMBTU		Good combustion practices
IL-0129	CPV THREE RIVERS ENERGY CENTER	Firewater Pump Engine	07/30/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			
IL-0130	JACKSON ENERGY CENTER	Firewater Pump Engine	12/31/2018	Carbon Dioxide Equivalent (CO_2e)	420	horsepower	241	TONS/YEAR	12-MONTH ROLLING AVERAGE	
IL-0133	LINCOLN LAND ENERGY CENTER	Fire Water Pump Engine	07/29/2022	Carbon Dioxide Equivalent (CO_2e)	320	horsepower	92	TONS/YEAR		
IL-0134	CRONUS CHEMICALS	Firewater Pump Engine	12/21/2023	Carbon Dioxide Equivalent (CO_2e)	369	hp	25	TONS/YEAR		
IN-0359	NUCOR STEEL	Emergency Generator (CC-GEN2)	03/30/2023	Carbon Dioxide Equivalent (CO_2e)	500	Horsepower	163.6	LB/MMBTU		Good engineering design and manufacturer's recommended operating and maintenance procedures.
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Emergency diesel engine	07/14/2015	Carbon Dioxide Equivalent (CO_2e)	750	KW	59.5	TONS PER YEAR	12-MONTH ROLLING AVERAGE	

Table D-5.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-01 - Melt Shop Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	260	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-02 - Reheat Furnace Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-03 - Rolling Mill Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	440	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-04 - IT Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	190	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
KY-0110	NUCOR STEEL BRANDENBURG	EP 11-05 - Radio Tower Emergency Generator	07/23/2020	Carbon Dioxide Equivalent (CO_2e)	61	HP	0			This EP is required to have a Good Combustion and Operating Practices (GCOP) Plan.
LA-0306	TOPCHEM POLLOCK, LLC	Genenerator Engine DEG-16-1 (EQT035)	12/20/2016	Carbon Dioxide Equivalent (CO_2e)	460	horsepower	26	Y/YR	ANNUAL MAXIMUM	Meet NSPS Subpart IIII Limitations and Good Combustion Practices
LA-0306	TOPCHEM POLLOCK, LLC	Pump Engines DFP-16-1 (EQT036)	12/20/2016	Carbon Dioxide Equivalent (CO_2e)	225	horsepower	13	T/YR	ANNUAL MAXIMUM	Good Combustion Practices
LA-0306	TOPCHEM POLLOCK, LLC	Pump Engine DFP-16-2 (EQT037)	12/20/2016	Carbon Dioxide Equivalent (CO_2e)	225	horsepower	13	T/YR	ANNUAL MAXIMUM	Good Combustion Practices
LA-0309	BENTELER STEEL TUBE FACILITY	Firewater Pump Engines	06/04/2015	Carbon Dioxide Equivalent (CO_2e)	288	hp (each)	0			
LA-0313	ST. CHARLES POWER STATION	SCPS Emergency Diesel Firewater Pump 1	08/31/2016	Carbon Dioxide Equivalent (CO_2e)	282	HP	0			Good combustion practices
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel Firewater pump engines (6 units)	08/03/2016	Carbon Dioxide Equivalent (CO_2e)	425	hp	0			
LA-0314	INDORAMA LAKE CHARLES FACILITY	Diesel emergency generator engine - EGEN	08/03/2016	Carbon Dioxide Equivalent (CO_2e)	350	hp	0			
LA-0316	CAMERON LNG FACILITY	firewater pump engines (8 units)	02/17/2017	Carbon Dioxide Equivalent (CO_2e)	460	hp	0			good combustion practices
LA-0323	MONSANTO LULING PLANT	Standby Generator No. 9 Engine	01/09/2017	Carbon Dioxide Equivalent (CO_2e)	400	hp	0			Proper operation and limits on hours of operation for emergency engines and compliance with 40 CFR 60 Subpart IIII
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39A	05/02/2018	Carbon Dioxide Equivalent (CO_2e)	375	HP	28	T/YR		Good Combustion Practices
LA-0328	PLAQUEMINES PLANT 1	Emergency Diesel Engine Pump P-39B	05/02/2018	Carbon Dioxide Equivalent (CO_2e)	300	HP	28	T/YR		Good Combustion Practices

Table D-5.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0339	SHINTECH PLAQUEMINE PLANT 3	Emergency Diesel Fired IC Engines (EQT0454 - EQT0459)	01/19/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			Energy efficiency measures to minimize the amount of fuel used
LA-0370	WASHINGTON PARISH ENERGY CENTER	Emergency Fire Pump Engine (EQT0021, ENG-1)	04/27/2020	Carbon Dioxide Equivalent (CO_2e)	1.1	MM BTU/hr	9	TPY	ANNUAL MAXIMUM	Good combustion practices in order to comply with 40 CFR 60 Subpart IIII
LA-0381	EUEG-5 UNIT - GEISMAR PLANT	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	12/12/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			Good engine design Good work practices
LA-0384	DIRECT REDUCED IRON FACILITY	IC Engines (EQT0153, EQT0154, EQT0156 - EQT0167)	06/13/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0386	LASALLE BIOENERGY LLC	Generators and Firewater Pumps Engines	05/05/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			Comply with 40 CFR 60 Subpart IIII
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Emergency Diesel Fired Water Pump Engine	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	355	hp	74.21	KG/MM BTU		Compliance with 40 CFR 60 Subpart IIII, good combustion practices, and the use of ultra-low sulfur diesel fuel.
LA-0402	DESTREHAN OIL PROCESSING FACILITY	HLK39 - Emergency Diesel Fire Pump Engine (EQT0094)	12/13/2023	Carbon Dioxide Equivalent (CO_2e)	200	horsepower	12	T/YR	ANNUAL MAXIMUM	Good Combustion Practices
MI-0423	INDECK NILES, LLC	EUFPENGINE (Emergency engine--diesel fire pump)	01/04/2017	Carbon Dioxide Equivalent (CO_2e)	1.66	MMBTU/H	13.58	T/YR	12 MO. ROLLING TIME PERIOD	Good combustion practices
MI-0424	HOLLAND BOARD OF PUBLIC WORKS - EAST 5TH STREET	EUFPENGINE (Emergency engine--diesel fire pump)	12/05/2016	Carbon Dioxide Equivalent (CO_2e)	500	H/YR	55.6	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (South Plant): Fire pump engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUFPENGINE (North Plant): Fire pump engine	06/29/2018	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MONTH ROLLING TIME PERIOD	Good combustion practices.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUFPENGINE: Fire pump engine	07/16/2018	Carbon Dioxide Equivalent (CO_2e)	399	BHP	86	T/YR	12-MO ROLLING TIME PERIOD	Energy efficient design
MI-0441	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	2.5	MMBTU/H	20	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices and energy efficiency measures.
MI-0445	INDECK NILES, LLC	EUFPENGINE (Emergency engine-diesel fire pump	11/26/2019	Carbon Dioxide Equivalent (CO_2e)	1.66	MMBTU/H	13.58	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices
MI-0447	LBWL--ERICKSON STATION	EUFPRICE--A 315 HP diesel fueled emergency engine	01/07/2021	Carbon Dioxide Equivalent (CO_2e)	2.5	MMBTU/H	20	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.
MI-0451	MEC NORTH, LLC	EUFPENGINE (North Plant): Fire Pump Engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices

Table D-5.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
MI-0452	MEC SOUTH, LLC	EUFPENGINE (South Plant): Fire pump engine	06/23/2022	Carbon Dioxide Equivalent (CO_2e)	300	HP	85.6	T/YR	12-MO ROLLING TIME PERIOD	Good combustion practices.
MI-0453	GENERAL MOTORS LLC ORION ASSEMBLY	FGEMENGINES	09/27/2022	Carbon Dioxide Equivalent (CO_2e)	500	h/yr	656.2	T/YR	12-MO ROLLING TIME PERIOD	Hours of Operation Restriction, Good Combustion Practices, Compliance with NSPS
MI-0454	LBWL-ERICKSON STATION	EUFPRICE--A 315 HP diesel-fueled emergency engine	12/20/2022	Carbon Dioxide Equivalent (CO_2e)	2.5	MMBTU/H	20	T/YR	12-MO ROLLING TIME PERIOD	Low carbon fuel (pipeline quality natural gas), good combustion practices, and energy efficiency measures.
NY-0103	CRICKET VALLEY ENERGY CENTER	Emergency fire pump	02/03/2016	Carbon Dioxide Equivalent (CO_2e)	460	hp	115	TPY	MO	Good combustion practice and efficient engine design.
OH-0366	CLEAN ENERGY FUTURE - LORDSTOWN, LLC	Emergency fire pump engine (P004)	08/25/2015	Carbon Dioxide Equivalent (CO_2e)	140	HP	41	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0367	SOUTH FIELD ENERGY LLC	Emergency fire pump engine (P004)	09/23/2016	Carbon Dioxide Equivalent (CO_2e)	311	HP	90	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0368	PALLAS NITROGEN LLC	Emergency Fire Pump Diesel Engine (P008)	04/19/2017	Carbon Dioxide Equivalent (CO_2e)	460	HP	123	T/YR	PER ROLLING 12 MONTH PERIOD	good combustion control and operating practices and engines designed to meet the stands of 40 CFR Part 60, Subpart IIII
OH-0370	TRUMBULL ENERGY CENTER	Emergency fire pump engine (P004)	09/07/2017	Carbon Dioxide Equivalent (CO_2e)	300	HP	87	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design
OH-0372	OREGON ENERGY CENTER	Emergency fire pump engine (P004)	09/27/2017	Carbon Dioxide Equivalent (CO_2e)	300	HP	87	T/YR	PER ROLLING 12 MONTH PERIOD	State-of-the-art combustion design
OH-0374	GUERNSEY POWER STATION LLC	Emergency Fire Pump (P006)	10/23/2017	Carbon Dioxide Equivalent (CO_2e)	410	HP	29	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
OH-0376	IRONUNITS LLC - TOLEDO HBI	Emergency diesel-fueled fire pump (P006)	02/09/2018	Carbon Dioxide Equivalent (CO_2e)	250	HP	163.6	LB/MMBTU		Equipment design and maintenance requirements
OH-0377	HARRISON POWER	Emergency Fire Pump (P004)	04/19/2018	Carbon Dioxide Equivalent (CO_2e)	320	HP	18.67	T/YR	PER ROLLING 12 MONTH PERIOD	Efficient design and proper maintenance and operation
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Firewater Pumps (P005 and P006)	12/21/2018	Carbon Dioxide Equivalent (CO_2e)	402	HP	23	T/YR	PER ROLLING 12 MONTH PERIOD	good operating practices (proper maintenance and operation)
OH-0379	PETMIN USA INCORPORATED	Black Start Generator (P007)	02/06/2019	Carbon Dioxide Equivalent (CO_2e)	158	HP	181.7	LB/H		Tier IV engine Good combustion practices
OH-0383	PETMIN USA INCORPORATED	Black Start Generator (P007)	07/17/2020	Carbon Dioxide Equivalent (CO_2e)	158	HP	9.09	T/YR		Tier IV engine Good combustion practices
OH-0388	IRON UNITS LLC	P010 - 225 Hp Diesel engine for bulk material screen	12/22/2022	Carbon Dioxide Equivalent (CO_2e)	225	HP	1209	T/YR	PER ROLLING 12-MONTH PERIOD	Good combustion practices

Table D-5.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0388	IRON UNITS LLC	P012 - 125 Hp Diesel Engine for Screen Bypass Screen	12/22/2022	Carbon Dioxide Equivalent (CO_2e)	125	HP	65	T/YR	PER ROLLING 12-MONTH PERIOD	Good combustion practices
OH-0388	IRON UNITS LLC	P011 and P013 - 100 Hp Diesel Engine	12/22/2022	Carbon Dioxide Equivalent (CO_2e)	100	HP	539	T/YR	PER ROLLING 12-MONTH PERIOD	Good combustion practices
OK-0164	MIDWEST CITY AIR DEPOT	Diesel-Fueled Fire Pump Engines	01/08/2015	Carbon Dioxide Equivalent (CO_2e)	300	HP	44	TONS PER YEAR	TOTAL FOR 3 ENGINES.	1. Good Combustion Practices. 2. Efficient Design.
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Fire pump engine	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	15	gal/hr	9	TON	12-MONTH ROLLING BASIS	
PA-0326	SHELL POLYMERS MONACA SITE	Emergency Generator Parking Garage	02/18/2021	Carbon Dioxide Equivalent (CO_2e)	0		10	TONS	YEARLY ON 12 MONTH ROLLING	Good Combustion Practices - no feasible control technologies, 10 tons CO2e Year 12 month rolling basis for Parking Garage and Telecom emergency generators combined
PA-0326	SHELL POLYMERS MONACA SITE	Emergency GeneratorTelecom Hut & Tower	02/18/2021	Carbon Dioxide Equivalent (CO_2e)	0		10	TONS	YEARLY ON 12 MONTH ROLLING	Good Combustion Practices - no feasible control technologies, 10 tons CO2e Year 12 month rolling basis for Parking Garage and Telecom emergency generators combined
SC-0182	FIBER INDUSTRIES LLC	Emergency Fire Pumps	10/31/2017	Carbon Dioxide Equivalent (CO_2e)	0		200	OPERATING HR/YR	EACH ENGINE	Use of Ultra Low Sulfur Diesel Fuel (15 ppm), good combustion, operation, and maintenance practices; compliance with NESHAP Subpart ZZZZ
TX-0799	BEAUMONT TERMINAL	EMERGENCY ENGINES	06/08/2016	Carbon Dioxide Equivalent (CO_2e)	0		6.79	T/YR		Equipment specifications and good combustion practices. Operation limited to 100 hours per year.
TX-0824	JACKSON COUNTY GENERATING FACILITY	Emergency Diesel-Fired Equipment	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	160	HP	13	T/YR		Good operating and maintenance practices, efficient design, and low annual capacity
TX-0846	MOTOR VEHICLE ASSEMBLY PLANT	FIRE PUMP DIESEL ENGINE	09/23/2018	Carbon Dioxide Equivalent (CO_2e)	214	kW	0			Meets EPA Tier 4 requirements . Fuels with a low carbon density, regular equipment maintenance, the use of efficient equipment and operation limited to less than 100 hr/yr
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	EMERGENCY DIESEL ENGINE	09/09/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			Tier 4 exhaust emission standards specified at 40 CFR § 1039.101(b)

Table D-5.7 Summary of CO_2e BACT Determinations for Small Engines

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0889	SWEENY OLD OCEAN FACILITIES	Emergency Generator Engines	08/08/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Good combustion practices and limited hours of operation
TX-0908	NEWMAN POWER STATION	Emergency Engine	08/27/2021	Carbon Dioxide Equivalent (CO_2e)	74	KW	0			Meet the requirements of 40 CFR Part 60, Subpart IIII. Firing ultra-low diesel fuel. Limited to 100 hrs/yr of non-emergency operation.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Carbon Dioxide Equivalent (CO_2e)	500	HR/YR	1040	T/YR	12 MO ROLLING TOTAL	good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
VA-0328	C4GT, LLC	Emergency Fire Water Pump	04/26/2018	Carbon Dioxide Equivalent (CO_2e)	500	HR/YR	1040	T/YR	12 MO ROLLING TOTAL	
VA-0332	CHICKAHOMINY POWER LLC	Emegency Fire Water Pump	06/24/2019	Carbon Dioxide Equivalent (CO_2e)	500	HR/YR	106	T/YR	12 MO ROLLING TOTAL	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.
WI-0292	GREEN BAY PACKAGING INC. MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Carbon Dioxide Equivalent (CO_2e)	0		200	HOURS	12-MONTH PERIOD	Hours of Operation
WI-0292	GREEN BAY PACKAGING INC. MILL DIVISION	P37 Diesel-Fired Emergency Fire Pump	04/01/2019	Carbon Dioxide Equivalent (CO_2e)	0		200	HOURS	12-MONTH PERIOD	
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	282	HP	0			Be certified by manufacturer to EPA's criteria for Tier 3 reciprocating internal combustion engines and to the 40 CFR 60, Subpart IIII emission limitations, operation limited to 500 hours/year, and operate and maintain according to the manufacturer's recommendations.
WI-0300	NEMADJI TRAIL ENERGY CENTER	Emergency Diesel Fire Pump (P06)	09/01/2020	Carbon Dioxide Equivalent (CO_2e)	282	HP	0			

Table D-6.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0161	SUN BIO MATERIAL COMPANY	Cooling Towers	09/23/2019	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT LOSS		Drift Eliminators Low TDS
FL-0363	DANIA BEACH ENERGY CENTER	Mechanical draft cooling system	12/04/2017	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT RATE		Certified drift rate < 0.0005%
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Mechanical Draft Auxiliary Cooling System	07/27/2018	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT RATE		Certified drift rate < 0.0005%
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Mechanical Draft Auxiliary Cooling System	06/07/2021	Particulate matter, filterable (FPM)	0		0.0005	% DRIFT RATE		Certified drift rate < 0.0005%
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-01 - Melt Shop ICW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	52000	gal/min	0.36	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-02 - Melt Shop DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	5900	gal/min	0.04	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-03 - Rolling Mill ICW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	8500	gal/min	0.06	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-04 - Rolling Mill DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	22750	gal/min	0.17	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-05 - Rolling Mill Quench/ACC Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	90000	gal/min	0.78	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-06 - Light Plate Quench DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	8000	gal/min	0.06	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-07 - Heavy Plate Quench DCW Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	3000	gal/min	0.02	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0110	NUCOR STEEL BRANDENBURG	EP 09-08 - Air Separation Plant Cooling Tower	07/23/2020	Particulate matter, filterable (FPM)	14000	gal/min	0.1	LB/HR		High Efficiency Mist Eliminator. The mist eliminator drift loss shall be maintained at 0.001% or less to total gpm.
KY-0115	NUCOR STEEL GALLATIN, LLC	Laminar Cooling Tower - Hot Mill Cells (EP 03-09)	04/19/2021	Particulate matter, filterable (FPM)	35000	gal/min	0.27	LB/HR		Mist Eliminator, 0.001% drift loss

Table D-6.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0115	NUCOR STEEL GALLATIN, LLC	Direct Cooling Tower-Caster & Roughing Mill Cells (EP 03-10)	04/19/2021	Particulate matter, filterable (FPM)	26300	gal/min	0.17	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	Melt Shop #2 Cooling Tower (indirect) (EP 03-11)	04/19/2021	Particulate matter, filterable (FPM)	59500	gal/min	0.39	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	Cold Mill Cooling Tower (EP 03-12)	04/19/2021	Particulate matter, filterable (FPM)	20000	gal/min	0.14	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	Air Separation Plant Cooling Tower (EP 03-13)	04/19/2021	Particulate matter, filterable (FPM)	15000	gal/min	0.08	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0115	NUCOR STEEL GALLATIN, LLC	DCW Auxiliary Cooling Tower (EP 03-14)	04/19/2021	Particulate matter, filterable (FPM)	9250	gal/min	0.06	LB/HR		Mist Eliminator, 0.001% drift loss
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 043 - Cooling Tower #1	07/25/2022	Particulate matter, filterable (FPM)	0.15	MMgal/hr	0.013	LB/HR	MONTHLY AVERAGE	Mist Eliminator (0.001% drift loss), Total Dissolved Solids (TDS) concentration limit of 1000 ppm
MI-0427	FILER CITY STATION	EUCOOLTWR (Cooling Tower--Wet Mechanical Drift)	11/17/2017	Particulate matter, filterable (FPM)	0		0.0006	%	VENDOR-CERTIFIED MAX. DRIFT RATE	Mist/Drift Eliminators
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUCOOLTOWER (North Plant): Cooling Tower	06/29/2018	Particulate matter, filterable (FPM)	170000	GAL/M	5.59	T/YR	12-MONTH ROLLING TIME PERIOD	High efficiency drift/mist eliminators
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	EUCOOLTOWER (South Plant): Cooling Tower	06/29/2018	Particulate matter, filterable (FPM)	170000	GAL/M	5.59	T/YR	12-MO ROLLING TIME PERIOD	High efficiency drift/mist eliminators.
MI-0435	BELLE RIVER COMBINED CYCLE POWER PLANT	EUCOOLINGTWR: Cooling Tower	07/16/2018	Particulate matter, filterable (FPM)	0		4.03	LB/H	HOURLY	High efficiency drift/mist eliminators
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Contact Cooling Towers - Melt Shop 2 (P027)	09/27/2019	Particulate matter, filterable (FPM)	2.7	MMGAL/H	1.17	T/YR	PER ROLLING, 12-MONTH PERIOD.	i.use of drift eliminator(s) designed to achieve a 0.001% drift rate; ii.maintenance of a total

Table D-6.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Contact Cooling Towers (P014)	09/27/2019	Particulate matter, filterable (FPM)	6.41	MMGAL/H	8.7	T/YR	PER ROLLING, 12-MONTH PERIOD.	i.use of drift eliminator(s) designed to achieve a 0.003% drift rate; ii.maintenance of a total dissolved solids (TDS) content (for the 5 individual cooling towers) not to exceed the ppm in the circulating cooling water based on a rolling 12-month average as indicated in the table below: Cooling Tower - TDS (ppm) Meltshop Cooling Tower (501) - 800 Caster Non-Contact Cooling Tower (6 Cell) - 800 Caster Contact Cooling Tower (503) - 1100 Mill Contact Cooling Tower (505) - 2000 Laminar Flow Cooling Tower (506) - 1400
SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD	Cooling Towers	10/31/2023	Particulate matter, filterable (FPM)	0		0.001	% DRIFT RATE		Drift Eliminator
TX-0876	PORT ARTHUR ETHANE CRACKER UNIT	COOLING TOWER	02/06/2020	Particulate matter, filterable (FPM)	0		1200	PPM	TDS	DRIFT ELIMINATORS
TX-0933	NACERO PENWELL FACILITY	TURBINE	11/17/2021	Particulate matter, filterable (FPM)			0.0075	Lb/MMBtu		good combustion practices and the use of gaseous fuel
TX-0964	NEDERLAND FACILITY	COOLING TOWERS	10/05/2023	Particulate matter, filterable (FPM)	0		2000	PPMW	TDS	Drift eliminators with 0.001% drift

Table D-6.2 Summary of Total PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Mechanical draft cooling tower	03/09/2016	Particulate matter, total (TPM)	465815	gallons water/min	0			Must have certified drift rate no more than 0.0005%.
FL-0368	NUCOR STEEL FLORIDA FACILITY	Two Cooling Towers	02/14/2019	Particulate matter, total (TPM)	19650	gal/min	0.001	% DRIFT RATE		Drift eliminators
IN-0317	RIVERVIEW ENERGY CORPORATION	Cooling tower EU-6001	06/11/2019	Particulate matter, total (TPM)	32000	GAL/HR	2395	MG/L	TDS IN CIRCULATING WATER	drift eliminator
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Mechanical draft cooling tower	07/14/2015	Particulate matter, total (TPM)	0		0.0005	% DRIFT RATE		high efficiency drift eliminators (integral part of the design)
KS-0040	JOHNS MANVILLE AT MCPHERSON	Cooling Towers	12/03/2019	Particulate matter, total (TPM)	0		0.001	PERCENT	DRIFT RATE FROM EACH TOWERS	Drift Rate Control
MI-0442	THOMAS TOWNSHIP ENERGY, LLC	FGCOOLTWR	08/21/2019	Particulate matter, total (TPM)	92500	GAL/M	4.1	T/YR	12-MO ROLLING TIME PERIOD	Particulate in water droplets will be controlled with high efficiency drift/mist eliminators.
NE-0059	AGP SOY	Cooling Tower	03/25/2015	Particulate matter, total (TPM)	360000	gal/hr	0.0005	%	DRIFT LOSS	drift loss design specification and TDS concentration limit
NE-0064	NORFOLK CRUSH, LLC	Cooling Tower	11/21/2022	Particulate matter, total (TPM)	480060	gal/hr	0.0005	%	DRIFT LOSS	There is a drift loss design specification and a TDS concentration limit.
NE-0068	AG PROCESSING INC - DAVID CITY	Cooling Tower 1	06/27/2023	Particulate matter, total (TPM)	759600	gal/hr	0.0005	%		There is a drift loss design specification with the mist eliminator (CE-8000) and a TDS concentration limit.
NE-0068	AG PROCESSING INC - DAVID CITY	Cooling Tower 2	06/27/2023	Particulate matter, total (TPM)	303840	gal/hr	0.0005	%		There is a drift loss design specification with the mist eliminator (CE-8001) and a TDS concentration limit.
OH-0364	OREGON ENERGY CENTER	Cooling Towers #1 & #2 (P009 & P010)	05/20/2015	Particulate matter, total (TPM)	115037	GAL/M	1.48	LB/H		advanced drift eliminators with a drift rate of less than 0.0005 percent and maintain the total dissolved solids (TDS) content of the circulating cooling water at 5,130 mg/L or less as a 24-hour rolling average

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Table D-6.2 Summary of Total PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0375	LONG RIDGE ENERGY GENERATION LLC - HANNIBAL POWER	Wet Mechanical Draft Cooling Tower (P003)	11/07/2017	Particulate matter, total (TPM)	120000	GAL/M	6.58	T/YR	PER ROLLING 12 MONTH PERIOD	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and total dissolved solids (TDS) content not to exceed 5,000 mg/l.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Cooling Tower (P011)	12/21/2018	Particulate matter, total (TPM)	13.88	MMGAL/H	5.07	T/YR	PER ROLLING 12 MONTH PERIOD	High efficiency drift eliminator designed to achieve a 0.0005% drift rate and maintenance of a total dissolved solids (TDS) content not to exceed 2,000 ppm in the circulating cooling water based on a rolling 12-month average.
OH-0387	INTEL OHIO SITE	Cooling Towers: P054 through P178	09/20/2022	Particulate matter, total (TPM)	0		0.0005	%	DRIFT RATE	Drift eliminator
OH-0391	VALENCIA PROJECT LLC	Cooling Towers (P023, P024, P025)	10/27/2023	Particulate matter, total (TPM)	0		0.05	LB/H	SEE NOTES	A drift eliminator achieving â€œdrift lossâ€ equal to or less than 0.0005 percent
TX-0832	EXXONMOBIL BEAUMONT REFINERY	COOLING TOWERS	01/09/2018	Particulate matter, total (TPM)	0		0			DRIFT ELIMINATOR
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	COOLING TOWER	03/30/2018	Particulate matter, total (TPM)	9864000	GAL/H	0			DRIFT ELIMINATORS
TX-0834	MONTGOMERY COUNTY POWER STATIOIN	COOLING TOWER	03/30/2018	Particulate matter, total (TPM2.5)	9864000	GAL/H	0			DRIFT ELIMINATORS
TX-0864	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	Cooling Tower	09/09/2019	Particulate matter, total (TPM)	0		0.005	% DRIFT		drift eliminators
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	COOLING TOWER	09/09/2019	Particulate matter, total (TPM)	0		6000	PPMW	TDS	DRIFT ELIMINATORS
TX-0873	PORT ARTHUR REFINERY	COOLING TOWER	02/04/2020	Particulate matter, total (TPM)	35000	GPM	0			DRIFT ELIMINATORS
TX-0888	ORANGE POLYETHYLENE PLANT	COOLING TOWERS	04/23/2020	Particulate matter, total (TPM)	0		0			DRIFT ELIMINATORS
TX-0904	MOTIVA POLYETHYLENE MANUFACTURING COMPLEX	COOLING TOWER	09/09/2020	Particulate matter, total (TPM)	0		1200	PPMW		Non-contact design and DRIFT ELIMINATORS
TX-0905	DIAMOND GREEN DIESEL PORT ARTHUR FACILITY	COOLING TOWER	09/16/2020	Particulate matter, total (TPM)	0		0			DRIFT ELIMINATORS 0.001%
TX-0915	UNIT 5	COOLING TOWER	03/17/2021	Particulate matter, total (TPM)	0		60000	PPM	TDS	Drift eliminators 0.0005%
TX-0922	HOUSTON PLANT - 46307	COOLING TOWER	06/13/2022	Particulate matter, total (TPM)	0		0			Drift eliminators with 0.0005% drift

Table D-6.2 Summary of Total PM10/PM2.5 BACT Determinations for Cooling Towers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0930	CENTURION BROWNSVILLE	Cooling Tower	10/19/2021	Particulate matter, total (TPM)	0		0			Drift eliminators required. Maximum drift 0.0005 percent. TDS limit of 3,500 ppmw in the cooling water. Daily sampling for TDS required, or weekly TDS sampling is allowed if conductivity is monitored daily and a TDS to conductivity ratio is established.
TX-0931	ROEHM AMERICA BAY CITY SITE	Cooling Tower	12/16/2021	Particulate matter, total (TPM)	0		0			Drift eliminators with 0.001% drift
TX-0938	VALERO CORPUS CHRISTI REFINERY WEST PLANT	COOLING TOWER	05/03/2024	Particulate matter, total (TPM)	0		0			Drift eliminators 0.001% drift
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	COOLING TOWER	03/13/2023	Particulate matter, total (TPM)	13734000	GAL/HR	0			0.001% DRIFT ELIMINATORS
TX-0940	FIBERGLASS MANUFACTURING FACILITY	COOLING TOWER	09/06/2022	Particulate matter, total (TPM)	2175	GAL/MIN	0.001	%		DRIFT ELIMINATOR
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	COOLING TOWERS	02/05/2024	Particulate matter, total (TPM)	142700	gal/min	0			drift eliminators 0.0005%
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. -ENERGY PLANT	P02A-P & P03A-P Cooling Towers	04/24/2018	Particulate matter, total (TPM)	0		0			Drift Eliminator& Cooling Additive Control System
WI-0311	SUPERIOR REFINING COMPANY LLC	Cooling Tower No.1 (P80)	09/27/2019	Particulate matter, total (TPM)	10000	GPM	0.0005	% CIRCULATION DRIFT		Drift eliminator, cooling additive control system that results in a total dissolved solids (TDS) concentration of not more than 3,000 ppm.

Table D-7.1 Summary of SF_6 BACT Determinations for Circuit Breakers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
FL-0354	LAUDERDALE PLANT	Circuit Breakers	08/25/2015	Sulfur Hexafluoride	0		0.5	% PER YEAR	MUST HAVE CERTIFIED LEAK RATE LESS THAN	Limitation on leaks
FL-0355	FORT MYERS PLANT	Circuit breakers	09/10/2015	Sulfur Hexafluoride	0		0.5	PERCENT	LEAK RATE PER YEAR	Limitation on leak of SF6 from circuit breakers
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	Circuit breakers	03/09/2016	Sulfur Hexafluoride	0		0			Leak prevention. Must have manufacturer-guaranteed leak rate no more than 0.5% per year. Must be equipped with leakage detection systems and alarms.
FL-0363	DANIA BEACH ENERGY CENTER	Circuit breakers (two)	12/04/2017	Sulfur Hexafluoride	0		0.5	% LEAK PER YEAR		Certified leak rate < 0.5% per year
FL-0367	SHADY HILLS COMBINED CYCLE FACILITY	Two Circuit Breakers	07/27/2018	Sulfur Hexafluoride	0		0.5	% LEAK PER YEAR		Certified leak rate < 0.5% per year
FL-0371	SHADY HILLS COMBINED CYCLE FACILITY	Two Circuit Breakers	06/07/2021	Sulfur Hexafluoride	0		0.5	% LEAK PER YEAR		Certified leak rate < 0.5% per year
IL-0129	CPV THREE RIVERS ENERGY CENTER	Circuit Breakers	07/30/2018	Sulfur Hexafluoride	0		0.5	% LEAK RATE	CALENDAR YEAR AVERAGE	
IL-0130	JACKSON ENERGY CENTER	Circuit Breakers	12/31/2018	Sulfur Hexafluoride	0		0.5	PERCENT LEAK RATE	CALENDAR YEAR AVERAGE	
IL-0133	LINCOLN LAND ENERGY CENTER	Circuit Breakers	07/29/2022	Sulfur Hexafluoride	0		0.5	PERCENT LEAK RATE	12-MONTH ROLLING AVERAGE	
IN-0294	ST. JOSEPH ENERGY CENTER, LLC	Circuit Breakers SF6	08/08/2018	Sulfur Hexafluoride	0		0			
MD-0045	MATTAWOMAN ENERGY CENTER	CIRCUIT BREAKERS	11/13/2015	Sulfur Hexafluoride	0		0			
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Circuit breakers with SF6	12/23/2015	Sulfur Hexafluoride	0		6	LB/12MO	ANY 12 CONSECUTIVE MONTH PERIOD	low pressure alarms and low pressure lockout system

Table D-7.1 Summary of SF_6 BACT Determinations for Circuit Breakers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
PA-0310	CPV FAIRVIEW ENERGY CENTER	Circuit breakers	09/02/2016	Sulfur Hexafluoride	0		1500	PPM		State-of-the-art sealed enclosed-pressure circuit breakers with leak detection
WI-0299	WPL- RIVERSIDE ENERGY CENTER	Sulfur Hexafluoride Containing Circuit Breakers and Transformers (F90)	08/20/2020	Sulfur Hexafluoride	0		0.5	% LEAK RATE, BY WGHT	ANNUALLY	

Table D-7.2 Summary of CO_2e BACT Determinations for Circuit Breakers

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KS-0029	THE EMPIRE DISTRICT ELECTRIC COMPANY	Insulated circuit breaker	07/14/2015	Carbon Dioxide Equivalent (CO_2e)	0		6.9	TONS PER YEAR		Installation of modern, totally enclosed SF6 circuit breakers with density (leak detection) alarms and a guaranteed loss rate of < 0.5 % by weight per year.
LA-0391	MAGNOLIA POWER GENERATING STATION UNIT 1	Circuit Breakers	06/03/2022	Carbon Dioxide Equivalent (CO_2e)	0		85	T/YR		Enclosed pressure design with a low pressure detection system with an alarm to limit SF6 leak rate to 0.5 % per year.
MD-0045	MATTAWOMAN ENERGY CENTER	CIRCUIT BREAKERS	11/13/2015	Carbon Dioxide Equivalent (CO_2e)	0		0			GHG BACT FOR THE CIRCUIT BREAKERS SHALL BE INSTALLATION OF STATE-OF-THE-ART CIRCUIT BREAKERS THAT ARE DESIGNED TO MEET ANSI
PA-0309	LACKAWANNA ENERGY CTR/JESSUP	Circuit breakers with SF6	12/23/2015	Carbon Dioxide Equivalent (CO_2e)	0		79.8	TONS	ANY 12 CONSECUTIVE MONTH PERIOD	
TX-0824	JACKSON COUNTY GENERATING FACILITY	Sulfur hexafluoride (SF6) insulated Electrical Equipment	06/30/2017	Carbon Dioxide Equivalent (CO_2e)	0		34.4	T/YR		The use of circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout is BACT
VA-0325	GREENSVILLE POWER STATION	CIRCUIT BREAKERS (11)	06/17/2016	Carbon Dioxide Equivalent (CO_2e)	0		1032	T/YR		Enclosed pressure type breaker and leak detection
VA-0325	GREENSVILLE POWER STATION	CIRCUIT BREAKERS (3)	06/17/2016	Carbon Dioxide Equivalent (CO_2e)	0		19	T/YR		Enclosed pressure type breaker and leak detector
VA-0328	C4GT, LLC	Circuit Breakers - 6	04/26/2018	Carbon Dioxide Equivalent (CO_2e)	0.5	%	0			Enclosed-pressure design with low-pressure detection system (with alarm).
VA-0332	CHICKAHOMINY POWER LLC	Circuit Breakers	06/24/2019	Carbon Dioxide Equivalent (CO_2e)	0.5	%	0			Enclosed-pressure design with low-pressure detection system (with alarm).
WI-0300	NEMADJI TRAIL ENERGY CENTER	Low-Side Generator Enclosed Pressure SF6 Circuit Breakers (F03)	9/1/2020	Carbon Dioxide Equivalent (CO_2e)	0		0.5	% BY WEIGHT/YEAR		

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Table D-9.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AK-0084	DONLIN GOLD PROJECT	Fuel Tanks	06/30/2017	Volatile Organic Compounds (VOC)	0		1.7	TPY	YEARLY	Submerged Fill
AK-0085	GAS TREATMENT PLANT	Fuel Tanks	08/13/2020	Volatile Organic Compounds (VOC)	0		0.59	TPY	YEAR	Submerged Fill
AK-0088	LIQUEFACTION PLANT	Three Diesel Storage Tanks	07/07/2022	Volatile Organic Compounds (VOC)	0		0.01	TPY COMBINED		Submerged Fill
FL-0354	LAUDERDALE PLANT	Two 3-million gallon ULSD storage tanks	08/25/2015	Volatile Organic Compounds (VOC)	0		0			Low vapor pressure prevents evaporative losses
IN-0273	ST. JOSEPH ENERGY CENTER	DIESEL STORAGE TANK TK11	06/22/2017	Volatile Organic Compounds (VOC)	650	GALLONS	0			THE USE OF GOOD DESIGN AND OPERATING PRACTICES. EACH TANK SHALL UTILIZE A FIXED ROOF.
IN-0273	ST. JOSEPH ENERGY CENTER	DIESEL STORAGE TANK TK50	06/22/2017	Volatile Organic Compounds (VOC)	5000	GALLONS	0			THE USE OF GOOD DESIGN AND OPERATING PRACTICES. EACH TANK SHALL UTILIZE A FIXED ROOF.
IN-0318	RIVERVIEW ENERGY CORPORATION	Diesel product tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		2.29	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Residue tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		0.0001	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Vacuum Gas Oil Tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		0.175	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Diesel fuel tank T17	06/11/2019	Volatile Organic Compounds (VOC)	0		0.0114	TONS	12 CONSECUTIVE MONTHS	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
IN-0318	RIVERVIEW ENERGY CORPORATION	Emergency engine fuel tanks	06/11/2019	Volatile Organic Compounds (VOC)	0		0.0114	TONS	PER 12 MONTH PERIOD, EACH	Tanks shall use a white shell. Tanks shall use submerged filling. Tanks shall use good maintenance practices as described in the permit.
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Diesel Storage Tank (EU76)	10/24/2016	Volatile Organic Compounds (VOC)	2000	gallons	0			The diesel storage tank (EU76) shall be equipped with a permanent submerged fill pipe.

Table D-9.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Gasoline Storage Tank (EU75)	10/24/2016	Volatile Organic Compounds (VOC)	2000	Gallon (Capacity)	0			The permittee shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following: i. Minimize gasoline spills; ii. Clean up spills as expeditiously as practicable; iii. Cover all open gasoline containers and all gasoline storage tank fill-pipes with a gasketed seal when not in use; iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators. The gasoline storage tank (EU75) shall be equipped with a permanent submerged fill pipe.
KY-0110	NUCOR STEEL BRANDENBURG	EP 15-02 - Gasoline Storage Tanks #1 & #2	07/23/2020	Volatile Organic Compounds (VOC)	2000	gal combined	0			The gasoline storage tanks (EP 15-02) shall be equipped with a permanent submerged fill pipe.
KY-0116	NOVELIS CORPORATION - GUTHRIE	EU 044 - Diesel Fuel Storage and Refueling Station	07/25/2022	Volatile Organic Compounds (VOC)	68000	gal/yr	0			Spill & overfill protection, Submerged fill pipes, & Good Work Practices (GWP) Plan
LA-0276	BATON ROUGE JUNCTION FACILITY	Vertical Fixed Roof Tanks 174, 175, 176	12/15/2016	Volatile Organic Compounds (VOC)	0		0			Submerged fill pipes and pressure/vacuum vents
LA-0309	BENTELER STEEL TUBE FACILITY	Gasoline Tank S16	06/04/2015	Volatile Organic Compounds (VOC)	600	gallons	0			Submerged fill pipe
LA-0314	INDORAMA LAKE CHARLES FACILITY	Unleaded Gasoline Tank TK-33	08/03/2016	Volatile Organic Compounds (VOC)	1000	gallons	0			Submerged fill pipe and LAC 33:III.2103
LA-0399	TEAL JONES-PLAIN DEALING SAW MILL	Small Gasoline and Diesel Tanks	10/31/2022	Volatile Organic Compounds (VOC)	0		0			Light color, fixed roofs, submerged fill/bottom loading, and good operating practice
OK-0177	CUSHING SOUTH TANK FARM	4,000 GALLON SUMP TANK	01/04/2018	Volatile Organic Compounds (VOC)	208000	BBL/YR	0			Submerged fill and good housekeeping, including quarterly inspection requirements in the SPCC plan.
SC-0193	MERCEDES BENZ VANS, LLC	Storage Tank	04/15/2016	Volatile Organic Compounds (VOC)	5000	gal	0			Stage 1 Vapor Control
TX-0731	CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	Petroleum Liquids Storage in Fixed Roof Tanks	04/10/2015	Volatile Organic Compounds (VOC)	3.4	MMBbl/yr/tank	15.78	TONS/YR/TANK		Temperature reduced to maintain volatile organic compound (VOC) vapor pressure < 0.5 pounds per square inch actual (psia) at all times.
TX-0756	CCI CORPUS CHRISTI CONDENSATE SPLITTER FACILITY	Storage Tanks, TK-110, TK-111, TK-112	06/19/2015	Volatile Organic Compounds (VOC)	57960	gal/hr	3.07	LB/HR		Tanks are required to be painted white and be equipped with submerged fill pipes
TX-0756	CCI CORPUS CHRISTI CONDENSATE SPLITTER FACILITY	Storage Tanks, TK-113, TK-114, and TK-115	06/19/2015	Volatile Organic Compounds (VOC)	47000000	gal/yr/tank	0.85	LB/HR		Tanks are required to be painted white and be equipped with submerged fill pipes

Table D-9.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD TERMINAL (PBPTT)	Petroleum Liquids Storage in Fixed Roof Tanks	11/06/2015	Volatile Organic Compounds (VOC)	47.62	BBL/YR	0.01	T/YR		Tank uses submerged fill and is aluminum in color.
TX-0799	BEAUMONT TERMINAL	Storage Tanks - fixed roof	06/08/2016	Volatile Organic Compounds (VOC)	0		72.5	T/YR		Fixed-roof tanks (EPNs 168, 222, 225, 227,229, 254, 256, 257, 258, 259, 475, and 476) will use submerged fill and have white exterior surfaces. Fuel tanks (EPN DTK01 and GTK01) are horizontal fixed-roof design and will use submerged fill and have white or aluminum exterior surfaces.
TX-0813	ODESSA PETROCHEMICAL PLANT	Petroleum Liquid Storage in Fixed Roof tanks	11/22/2016	Volatile Organic Compounds (VOC)	0		0.01	T/YR		Submerged fill pipe, reflective or white exterior paint.
TX-0840	CORPUS CHRISTI TERMINAL	Heavy oil storage	10/31/2018	Volatile Organic Compounds (VOC)	0		0			1 fixed roof tank has storage of heavy oil (EPN: T-1334) with VP < 0.5 psia, painted white and equipped with submerged fill pipe.
TX-0847	VALERO PORT ARTHUR REFINERY	Coker sludge feed tanks	09/16/2018	Volatile Organic Compounds (VOC)	12000	GAL/HR	100	PPM		NON REGENERATIVE CARBON ADSORBER
TX-0850	CORPUS CHRISTI TERMINAL	Heavy oil storage in fixed roof tank	07/15/2018	Volatile Organic Compounds (VOC)	0		0			Storage of heavy oil (EPN: T-1334) in a fixed roof tank with VP < 0.5 psia, painted white and equipped with submerged fill pipe.
TX-0855	BUCKEYE SOUTH TEXAS GATEWAY TERMINAL	Fixed Roof Tanks	03/13/2019	Volatile Organic Compounds (VOC)	0		0			painted white and equipped with the submerged fill piping.
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	FIXED ROOF TANKS	08/29/2019	Volatile Organic Compounds (VOC)	0		0			Painted White with Submerged Fill
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	FIXED ROOF TANKS	08/29/2019	Volatile Organic Compounds (VOC)	0		0			Painted White with Submerged Fill
TX-0888	ORANGE POLYETHYLENE PLANT	FIXED ROOF STORAGE TANKS	04/23/2020	Volatile Organic Compounds (VOC)	0		0			submerge fill piping or bottom fill piping and painted white
TX-0930	CENTURION BROWNSVILLE	Fixed Roof Storage Tanks	10/19/2021	Volatile Organic Compounds (VOC)	1260000	GAL/HR/TANK	0			Tanks must be painted white or unpainted aluminum, utilize submerged fill, and designed to be drain-dry.
TX-0930	CENTURION BROWNSVILLE	Fixed Roof Storage Tanks MSS	10/19/2021	Volatile Organic Compounds (VOC)	0		0			tanks containing VOC liquids alone or in combination with other liquids shall be depressurized and degassed to control until the vapor space concentration has been verified to be less than or equal to 4,000 ppmv. Tanks may be opened without restriction and ventilated without control when there is either no liquid and/or sludge remaining in the tank, or the vapor pressure of the liquid and/or sludge remaining in the tank has a vapor pressure less than 0.02 psia.

Table D-9.1 Summary of VOC BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0936	BILL GREEHEY REFINERY EAST PLANT	FIXED ROOF STORAGE TANKS	03/29/2022	Volatile Organic Compounds (VOC)	0		0			Vertical fixed roof tanks storing low vapor pressure products (vp < 0.5 psia) with submerged fill, painted white.
TX-0937	VALERO CORPUS CHRISTI REFINERY EAST PLANT	FIXED ROOF STORAGE TANKS	07/20/2023	Volatile Organic Compounds (VOC)	0		0			Vertical fixed roof tanks storing low vapor pressure products (vp < 0.5 psia) with submerged fill, painted white.
TX-0937	VALERO CORPUS CHRISTI REFINERY EAST PLANT	FIXED ROOF TANK MSS	07/20/2023	Volatile Organic Compounds (VOC)	0		0			Fixed roof tank draining: Send liquid to a covered vessel. If there is any standing liquid within the tank, and the tank is opened to the atmosphere or ventilated, the vapor stream must be controlled until there is no standing liquid or the VOC vapor pressure is less than 0.02 psia. Control device (portable combustor) has a minimum DRE of 99%. Maintain fixed roof tanks only when warranted by inspection.
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	STORAGE TANKS	03/13/2023	Volatile Organic Compounds (VOC)	0		0			Bottom fill, exterior surfaces are painted white, unpainted stainless steel, or unpainted aluminum.
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	Fixed Roof Storage Tanks	02/05/2024	Volatile Organic Compounds (VOC)	0		0			Submerged fill and uninsulated exterior surfaces exposed to the sun are painted white. Send liquid to a covered vessel when draining the tank.
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	FT02 Diesel Fuel Tank Storage	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Good Operating Practices
WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	T01, T02, &; T03 Diesel Storage Tank	04/24/2018	Volatile Organic Compounds (VOC)	0		0			Submerged Fill Pipe
WI-0300	NEMADJI TRAIL ENERGY CENTER	Diesel Fuel Day Tank (T01)	09/01/2020	Volatile Organic Compounds (VOC)	0		0			
WI-0300	NEMADJI TRAIL ENERGY CENTER	Diesel Fuel Generator Tank (T02)	09/01/2020	Volatile Organic Compounds (VOC)	0		0			
WI-0300	NEMADJI TRAIL ENERGY CENTER	Diesel Fuel Fire Pump Tank (T03)	09/01/2020	Volatile Organic Compounds (VOC)	0		0			
WI-0311	SUPERIOR REFINING COMPANY LLC	Asphalt Storage Tank (T100)	09/27/2019	Volatile Organic Compounds (VOC)	0		932.3	LB/MO	AVG., ANY 12-CONSECUTIVE MONTH PERIOD	Use of submerged fill pipe, may store only asphalt
WI-0311	SUPERIOR REFINING COMPANY LLC	Asphalt Storage Tank (T118)	09/27/2019	Volatile Organic Compounds (VOC)	0		1886.4	LB/MO	AVG., ANY 12-CONSECUTIVE MONTH PERIOD	Use of submerged fill pipe and tank may only store asphalt
WI-0311	SUPERIOR REFINING COMPANY LLC	Asphalt Storage Blending (T119)	09/27/2019	Volatile Organic Compounds (VOC)	0		448.1	LB/MO	AVG., ANY 12-CONSECUTIVE MONTH PERIOD	Use of submerged fill pipe and tank may store only asphalt
WI-0315	SUPERIOR REFINING COMPANY LLC	Storage Tanks (T88, T90, T91)	10/09/2020	Volatile Organic Compounds (VOC)	0		718.3	LB/MO	AVG., ANY 12-CONSECUTIVE MONTHS	Use of submerged fill pipe, may store only asphalt

Table D-9.2 Summary of CO_2e BACT Determinations for Storage Tanks

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0888	ORANGE POLYETHYLENE PLANT	FIXED ROOF STORAGE TANKS	04/23/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			submerge fill piping or bottom fill piping and painted white

Table D-10.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0172	NUCOR STEEL ARKANSAS	SN-122 SN-210 Paved Roads	09/01/2021	Particulate matter, total (TPM10)	0		3.9	LB/HR		Water Sprays, sweeping,
AR-0172	NUCOR STEEL ARKANSAS	SN-122 SN-210 Paved Roads	09/01/2021	Particulate matter, total (TPM2.5)	0		0.5	LB/HR		Water Sprays, sweeping,
AR-0173	BIG RIVER STEEL LLC	Paved Roadways	01/31/2022	Particulate matter, total (TPM10)	0		0.6	TPY		Development and Implementation of Fugitive Dust Control Plan
AR-0173	BIG RIVER STEEL LLC	Paved Roadways	01/31/2022	Particulate matter, total (TPM2.5)	0		0.2	TPY		Development and Implementation of Fugitive Dust Control Plan
IA-0117	SHELL ROCK SOY PROCESSING	Paved Road Fugitives	03/17/2021	Particulate matter, total (TPM)	0		2.97	TONS PER YEAR	PM	sweeping
IL-0129	CPV THREE RIVERS ENERGY CENTER	Roadways	07/30/2018	Particulate matter, total (TPM)	0		10	% OPACITY		Paving is required for roads used by trucks transporting bulk materials.
IL-0130	JACKSON ENERGY CENTER	Roadways	12/31/2018	Particulate matter, total (TPM)	0		10	PERCENT OPACITY		
IL-0132	NUCOR STEEL KANKAKEE, INC.	New and Modified Roadways	01/25/2021	Particulate matter, total (TPM)	0		0			Roadways shall be paved; speed limit posting of 15 miles/hour; best management practices to reduce fugitive emissions in accordance with written operating program that provides for cleaning or treatment of roadways
IL-0132	NUCOR STEEL KANKAKEE, INC.	New and Modified Roadways	01/25/2021	Particulate matter, total (TPM10)	0		0			Roadways shall be paved; speed limit posting of 15 miles/hour; best management practices to reduce fugitive emissions in accordance with written operating program that provides for cleaning or treatment of roadways
IL-0132	NUCOR STEEL KANKAKEE, INC.	New and Modified Roadways	01/25/2021	Particulate matter, total (TPM2.5)	0		0			Roadways shall be paved; speed limit posting of 15 miles/hour; best management practices to reduce fugitive emissions in accordance with written operating program that provides for cleaning or treatment of roadways
IL-0133	LINCOLN LAND ENERGY CENTER	Roadways	07/29/2022	Particulate matter, total (TPM)	0		10	PERCENT OPACITY	FROM FUGITIVE EMISSIONS	

Table D-10.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IL-0134	CRONUS CHEMICALS	Roadways	12/21/2023	Particulate matter, total (TPM10)	0		10	PERCENT	OPACITY FROM ROADWAYS	Paving of all roadways and Fugitive Dust Control Plan, including mitigative measures (sweeping, water sprays, prompt cleanups)
IL-0134	CRONUS CHEMICALS	Roadways	12/21/2023	Particulate matter, total (TPM2.5)	0		10	PERCENT	OPACITY FROM ROADWAYS	Paving of all roadways and Fugitive Dust Control Plan, including mitigative measures (sweeping, water sprays, prompt cleanups)
IN-0317	RIVERVIEW ENERGY CORPORATION	Paved roads	06/11/2019	Particulate matter, total (TPM)	0		1	MIN	VISIBLE EMISSIONS IN ANY ONE (1) HR	Fugitive dust control plan
IN-0317	RIVERVIEW ENERGY CORPORATION	Paved roads	06/11/2019	Particulate matter, total (TPM10)	0		1	MIN	VISIBLE EMISSIONS IN ANY ONE (1) HR	Fugitive dust control plan
IN-0317	RIVERVIEW ENERGY CORPORATION	Paved roads	06/11/2019	Particulate matter, total (TPM2.5)	0		1	MIN	VISIBLE EMISSIONS IN ANY ONE (1) HR	Fugitive dust control plan
IN-0324	MIDWEST FERTILIZER COMPANY LLC	Fugitive dust from paved roads and parking lots	05/06/2022	Particulate matter, total (TPM10)	0		0			
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Paved Roadways (EU76)	10/24/2016	Particulate matter, total (TPM10)	0.43	Miles (length)	0			The permittee shall vacuum sweep the pavement at least weekly, except during recent rain events, or as needed in the event of a spill.
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Paved Roadways (EU76)	10/24/2016	Particulate matter, total (TPM2.5)	0.43	Miles (length)	0			The permittee shall vacuum sweep the pavement at least weekly, except during recent rain events, or as needed in the event of a spill.
KY-0115	NUCOR STEEL GALLATIN, LLC	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	04/19/2021	Particulate matter, total (TPM10)	0		0			Sweeping & Watering
KY-0115	NUCOR STEEL GALLATIN, LLC	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	04/19/2021	Particulate matter, total (TPM2.5)	0		0			Sweeping & Watering
LA-0379	SHINTECH PLAQUEMINES PLANT 1	Fugitive Dust (Paved Roads)	05/04/2021	Particulate matter, total (TPM10)	0		0.08	LB/HR		Paving plant road as much as practicable.
LA-0379	SHINTECH PLAQUEMINES PLANT 1	Fugitive Dust (Paved Roads)	05/04/2021	Particulate matter, total (TPM)	0		0.08	LB/HR		Paving plant road as much as practicable.
LA-0382	BIG LAKE FUELS METHANOL PLANT	Paved Roads (FUG0004)	04/25/2019	Particulate matter, total (TPM10)	0		0			Proper maintenance

Table D-10.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0382	BIG LAKE FUELS METHANOL PLANT	Paved Roads (FUG0004)	04/25/2019	Particulate matter, total (TPM2.5)	0		0			Proper maintenance
OH-0368	PALLAS NITROGEN LLC	Paved Roadways (F001)	04/19/2017	Particulate matter, total (TPM10)	70000	MI/YR	2.6	T/YR		i.Paving of all plant roads that will be used for raw material and product transport; ii.Covering, at all times, of open-bodied vehicles when transporting materials likely to become airborne; and iii.Compliance with the opacity limits. Specifically, additional mitigation measures potentially including road sweeping or wet suppression will be implemented on an as-needed basis determined through visual observation of emissions associated with truck movements on the plant site.
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Facility Roadways (F001)	12/21/2018	Particulate matter, total (TPM10)	182865	MI/YR	0.38	T/YR	PER ROLLING 12 MONTH PERIOD	i.Pave all in-plant haul roads and parking areas; ii.Implement best management practices including posting and limiting vehicle speeds to 20 miles per hour and water spraying or sweeping as needed based on the daily inspections conducted
OH-0378	PTTGCA PETROCHEMICAL COMPLEX	Facility Roadways (F001)	12/21/2018	Particulate matter, total (TPM2.5)	182865	MI/YR	0.09	T/YR	PER ROLLING 12 MONTH PERIOD	i.Pave all in-plant haul roads and parking areas; ii.Implement best management practices including posting and limiting vehicle speeds to 20 miles per hour and water spraying or sweeping as needed based on the daily inspections conducted
OH-0380	AMG VANADIUM LLC	Paved Roadways (F001)	08/07/2019	Particulate matter, total (TPM10)	31689	MI/YR	0.06	T/YR	PER ROLLING 12-MONTH PERIOD.	Pave all in-plant haul roads and parking areas. Implement best management practices including posting and limiting vehicle speeds to 15 miles per hour in production areas. Utilize a vacuum sweeper as needed based on the daily inspections

Table D-10.2 Summary of Total PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0380	AMG VANADIUM LLC	Paved Roadways (F001)	08/07/2019	Particulate matter, total (TPM2.5)	31689	MI/YR	0.01	T/YR	PER ROLLING 12-MONTH PERIOD.	Pave all in-plant haul roads and parking areas. Implement best management practices including posting and limiting vehicle speeds to 15 miles per hour in production areas. Utilize a vacuum sweeper as needed based on the daily inspections
SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD PLANT	Roads	10/31/2023	Particulate matter, total (TPM10)	0		0			Paving and maintaining all roads
SC-0205	SCOUT MOTORS INC A DELAWARE CORPORATION - BLYTHEWOOD PLANT	Roads	10/31/2023	Particulate matter, total (TPM2.5)	0		0			Paving and maintaining all roads
WI-0310	NEMADJI TRAIL ENERGY CENTER	Haul Roads (F01)	07/08/2021	Particulate matter, total (TPM)	0		520	TRUCK TRIPS/YR	ANY CONSECUTIVE 12-MO PERIOD	All roads and parking lots within the property boundary must be paved, 5 mph speed limits posted for all vehicles and develop, maintain, and implement a fugitive dust control plan.
WI-0310	NEMADJI TRAIL ENERGY CENTER	Haul Roads (F01)	07/08/2021	Particulate matter, total (TPM10)	0		520	TRUCK TRIPS/YR	ANY CONSECUTIVE 12-MO PERIOD	All roads and parking lots within the property boundary must be paved, 5 mph speed limits posted for all vehicles; and develop, maintain, and implement a fugitive dust control plan.

Table D-10.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
AR-0172	NUCOR STEEL ARKANSAS	SN-122 SN-210 Paved Roads	09/01/2021	Particulate matter, filterable (FPM)	0		15.2	LB/HR		Water Sprays, sweeping,
AR-0173	BIG RIVER STEEL LLC	Paved Roadways	01/31/2022	Particulate matter, filterable (FPM)	0		2.8	TPY		Development and Implementation of Fugitive Dust Control Plan
IN-0324	MIDWEST FERTILIZER COMPANY LLC	Fugitive dust from paved roads and parking lots	05/06/2022	Particulate matter, filterable (FPM2.5)	0		0			
KY-0109	FRITZ WINTER NORTH AMERICA, LP	Paved Roadways (EU76)	10/24/2016	Particulate matter, filterable (FPM)	0.43	Miles (length)	0			The permittee shall vacuum sweep the pavement at least weekly, except during recent rain events, or as needed in the event of a spill.
KY-0115	NUCOR STEEL GALLATIN, LLC	Paved Roads & Satellite Coil Yard (EPs 04-01 & 04-04)	04/19/2021	Particulate matter, filterable (FPM)	0		0			Sweeping & Watering
MO-0089	OWENS CORNING INSULATION SYSTEMS, LLC	haul roads	05/12/2016	Particulate matter, filterable (FPM)	0		0			vacuum sweep, wash, etc
OH-0376	IRONUNITS LLC - TOLEDO HBI	Paved roads (F001)	02/09/2018	Particulate matter, filterable (FPM10)	0		0.63	T/YR		water flushing and sweeping
OH-0376	IRONUNITS LLC - TOLEDO HBI	Paved roads (F001)	02/09/2018	Particulate matter, filterable (FPM2.5)	0		0.15	T/YR		water flushing and sweeping
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Plant Roadways & Parking Areas (F005)	09/27/2019	Particulate matter, filterable (FPM10)	686399	MI/YR	3.55	T/YR	PER ROLLING, 12-MONTH PERIOD.	Paved: sweeping, vacuuming, washing with water, and posted speed limits to comply with the applicable requirements. Unpaved: use of dust suppressant as necessary to comply with the applicable requirements.
OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	Plant Roadways & Parking Areas (F005)	09/27/2019	Particulate matter, filterable (FPM2.5)	686399	MI/YR	0.75	T/YR	PER ROLLING, 12-MONTH PERIOD.	Paved: sweeping, vacuuming, washing with water, and posted speed limits to comply with the applicable requirements. Unpaved: use of dust suppressant as necessary to comply with the applicable requirements.

Table D-10.1 Summary of Filterable PM10/PM2.5 BACT Determinations for Haul Roads

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
OH-0387	INTEL OHIO SITE	Facility paved roadways and parking areas	09/20/2022	Particulate matter, filterable (FPM2.5)	0		0.04	T/YR	PER ROLLING 12 MONTH PERIOD	Pave all roadways and parking areas and implement best management practices, including limiting vehicle speeds and water spraying or sweeping as needed based on daily inspections.
OH-0387	INTEL OHIO SITE	Facility paved roadways and parking areas	09/20/2022	Particulate matter, filterable (FPM10)	0		0.16	T/YR	PER ROLLING 12 MONTH PERIOD	Pave all roadways and parking areas and implement best management practices, including limiting vehicle speeds and water spraying or sweeping as needed based on daily inspections.
OH-0391	VALENCIA PROJECT LLC	Paved Roads (F001)	10/27/2023	Particulate matter, filterable (FPM2.5)	0		0.23	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
OH-0391	VALENCIA PROJECT LLC	Paved Roads (F001)	10/27/2023	Particulate matter, filterable (FPM10)	0		0.92	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
OH-0392	NUCOR STEEL MARION, INC.	Vehicular Traffic (F001)	02/27/2024	Particulate matter, filterable (FPM2.5)	0		0.63	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
OH-0392	NUCOR STEEL MARION, INC.	Vehicular Traffic (F001)	02/27/2024	Particulate matter, filterable (FPM10)	0		4.4	T/YR	PER ROLLING 12-MONTH PERIOD	Best available control measures pave all roadways, speed reduction, good housekeeping practices, and/or watering
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	Roads	11/03/2017	Particulate matter, filterable (FPM)	0		0.13	LB/VMT		Good housekeeping practices.
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	Roads	11/03/2017	Particulate matter, filterable (FPM10)	0		0.03	LB/VMT		Good housekeeping practices.
SC-0181	RESOLUTE FP US INC. - CATAWBA LUMBER MILL	Roads	11/03/2017	Particulate matter, filterable (FPM2.5)	0		0.01	LB/VMT		Good housekeeping practices.

Table D-11.1 Summary of VOC BACT Determinations for Natural Gas Pipeline Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
IN-0317	RIVERVIEW ENERGY CORPORATION	Block 4000 fugitive emissions	06/11/2019	Volatile Organic Compounds (VOC)	0		25.04	TONS	12 CONSECUTIVE MONTHS	Leak detection and repair (LDAR) program
LA-0282	ALLIANCE REFINERY	Unit Fugitives for the Low Sulfur Gasoline Unit (294-FF, FUG 0004)	04/02/2015	Volatile Organic Compounds (VOC)	0		15.43	LB/HR	HOURLY AVERAGE	Louisiana MACT Determination for Refinery Equipment Leaks (Fugitive Emission Sources) dated July 26, 1994
LA-0283	ALLIANCE REFINERY	UNIT FUGITIVES FOR LOW SULFUR GASOLINE UNIT (294-FF, FUG 0004)	08/14/2015	Volatile Organic Compounds (VOC)	0		15.43	LB/HR	HOURLY AVERAGE	LDAR: Louisiana MACT Determination for Refinery Equipment Leaks (Fugitive Emission Sources) dated July 26, 1994
LA-0284	ALLIANCE REFINERY	Unit Fugitives for Loading Docks (406-FF, FUG 11)	09/02/2015	Volatile Organic Compounds (VOC)	0		0			LDAR: 40 CFR 63 Subpart H
LA-0316	CAMERON LNG FACILITY	fugitive emissions	02/17/2017	Volatile Organic Compounds (VOC)	0		0			Complying with LAC 33:III.2111
LA-0331	CALCASIEU PASS LNG PROJECT	Fugitive Equipment Leaks	09/21/2018	Volatile Organic Compounds (VOC)	0		5	T/YR	ANNUAL TOTAL	Proper piping design and compliance with LAC 33:III.2111.
LA-0355	GARYVILLE REFINERY	Fugitives from Crude Unit, Coker Unit and FCCU	09/06/2018	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart GGGa
LA-0356	GARYVILLE REFINERY	Fugitive Emissions (Unit 305, Unit 333, Refinery, GRL)	09/27/2019	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart GGGa
LA-0362	LAKE CHARLES REFINERY, AREA D	Area D Process D Fugitives	07/18/2019	Volatile Organic Compounds (VOC)	0		24.44	LB/H		Compliance with the most stringent applicable Leak Detection and Repair (LDAR) program, which is Louisiana MACT Determination for Refineries with Consent Decree Enhancements.
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Fugitives (FUG0001)	09/03/2020	Volatile Organic Compounds (VOC)	0		0			Proper piping design and LDAR
LA-0385	GARYVILLE REFINERY	Refinery Fugitives	02/11/2021	Volatile Organic Compounds (VOC)	0		0			Comply with 40 CFR 60 Subpart GGGa (for components servicing streams with 10% or more VOC)
TX-0731	CORPUS CHRISTI TERMINAL CONDENSATE SPLITTER	, Petroleum Refining Equipment Leaks/Fugitive Emissions	04/10/2015	Volatile Organic Compounds (VOC)	100000	Bbl/day	36.6	TPY		Quarterly instrumental monitoring using a method 21 gas analyzer for all valves, pump seals, compressor seals, and agitator seals with a leak definition of 500 parts per million volume (ppmv) for valves and 2,000 ppmv for pump, compressor and agitator seals. Leaking components must be repaired within 15 days of detection of the leak.
TX-0756	CCI CORPUS CHRISTI CONDENSATE SPLITTER FACILITY	Fugitive Components	06/19/2015	Volatile Organic Compounds (VOC)	0		500	PPMV	VALVES	Fugitive Leak Detection and Repair (LDAR) program that requires quarterly monitoring of valves with a leak definition of 500 ppmv. Quarterly monitoring of pump and compressor seals with a leak definition of 2,000 ppmv.

Table D-11.1 Summary of VOC BACT Determinations for Natural Gas Pipeline Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0759	PORT ARTHUR REFINERY	Hydrocracking and Hydro-treating Fugitive Components	07/31/2015	Volatile Organic Compounds (VOC)	105	K BBL/DAY	500	PPM	VALVES, PUMPS, SEALS	Enhanced Fugitive Leak Detection and Repair (LDAR) program that requires quarterly monitoring of valves, pumps, and compressor seals with a leak definition of 500 ppmv. Enhancements to the LDAR program include: 1) Monitoring to be done with data loggers capable of assigning time stamps to individual monitoring events; 2) Repair of leaking components found during weekly physical inspections within 15 days; 3) First attempt of repair of any valve found with a VOC reading greater than 100 ppmv; 4) Conduct of annual training for all of all LDAR technicians in the application of Method 21 consistent with the requirements of the permit; 5) Performance of a third party audit by no later than December 31, 2015 and then at least once every two years thereafter to verify whether EPA Method 21 is being properly applied; 6) and Initiation of an optical gas imaging (OGI) enhanced monitoring program for equipment leaks at those process units subject to EPA Method 21. In addition to the enhanced program, Motiva has agreed to perform quarterly instrument monitoring on fugitive components in heavy liquid service as well as quarterly instrument monitoring on all connectors with a leak definition of 500
TX-0760	CORPUS CHRISTI TERMINAL	Fugitives	08/06/2015	Volatile Organic Compounds (VOC)	0		500	PPMV		Fugitive Leak Detection and Repair (LDAR) per the 28 MID Monitoring program that requires quarterly monitoring of all components with a leak definition of 500 ppmv and directed maintenance.
TX-0765	SUNOCO MARINE VESSEL LOADING OPERATIONS	Petroleum Refining Equipment Leaks/Fugitive Emissions	09/18/2015	Volatile Organic Compounds (VOC)	100	MMbbl/yr	10.13	TPY		Quarterly instrumental monitoring using a method 21 gas analyzer for all valves, pump seals, compressor seals, and agitator seals with a leak definition of 500 ppmv for valves and 2,000 ppmv for pump, compressor and agitator seals. Leaking components must be repaired within 15 days of detection of the leak.

Table D-11.1 Summary of VOC BACT Determinations for Natural Gas Pipeline Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	LNG Export Facility - Natural Gas Fugitive Emissions	02/17/2016	Volatile Organic Compounds (VOC)	0		21.65	T/YR		Work practice - leak detection and repair program (28 VHP LDAR program)
TX-0797	CORPUS CHRISTI TERMINAL	Petroleum Refining Equipment Leaks/Fugitive Emissions	05/04/2016	Volatile Organic Compounds (VOC)	0		500	PPM		Fugitive Leak Detection and Repair (LDAR) per the 28 MID Monitoring program that requires quarterly monitoring of all components with a leak definition of 500 ppmv and directed maintenance.
TX-0812	CRUDE OIL PROCESSING FACILITY	Equipment Leaks	10/31/2016	Volatile Organic Compounds (VOC)	0		8.72	T/YR		Quarterly instrumental monitoring of accessible pumps, compressors and valves in vapor or light liquid service, with leak definitions of 500 ppmv (valves) and 2,000
TX-0840	CORPUS CHRISTI TERMINAL	FUGITIVES	10/31/2018	Volatile Organic Compounds (VOC)	0		0			Fugitive Leak Detection and Repair (LDAR) per the 28 MID Monitoring program that requires quarterly monitoring of all components with a leak definition of 500 ppmv and directed maintenance.
TX-0847	VALERO PORT ARTHUR REFINERY	Equipment Leaks/Fugitive Emissions	09/16/2018	Volatile Organic Compounds (VOC)	0		0			28 VHP
TX-0850	CORPUS CHRISTI TERMINAL	FUGITIVES	07/15/2018	Volatile Organic Compounds (VOC)	0		0			28 MID
TX-0851	RIO BRAVO PIPELINE FACILITY	FUGITIVES	12/17/2018	Volatile Organic Compounds (VOC)	0		0			28VHP
TX-0852	CORPUS CHRISTI WATERFRONT TERMINAL	Fugitive Components	01/02/2019	Volatile Organic Compounds (VOC)	0		0			28LAER
TX-0855	BUCKEYE SOUTH TEXAS GATEWAY TERMINAL	Fugitives	03/13/2019	Volatile Organic Compounds (VOC)	0		0			28 VHP, 28PI LDAR
TX-0861	BUCKEYE TEXAS PROCESSING CORPUS CHRISTI FACILITY	FUGITIVES	08/29/2019	Volatile Organic Compounds (VOC)	0		0			28VHP LDAR
TX-0871	PORT ARTHUR REFINERY	Fugitives	01/31/2020	Volatile Organic Compounds (VOC)	0		0			28VHP leak detection and repair (LDAR)
TX-0872	CONDENSATE SPLITTER FACILITY	Fugitives (Routine)	10/31/2019	Volatile Organic Compounds (VOC)	0		15.63	LB/H		28VHP. Leak-less connectors.
TX-0872	CONDENSATE SPLITTER FACILITY	Product Sampling Vacuum Truck (MSS)	10/31/2019	Volatile Organic Compounds (VOC)	0		0			Contained in a sealable container. Best Management Practices including minimizing MSS activity and recordkeeping. Maximum sample size 32 oz.
TX-0873	PORT ARTHUR REFINERY	FUGITIVES	02/04/2020	Volatile Organic Compounds (VOC)	0		0			28 MID, 28 AVO and OGI fugitive programs. Authorized for infrared camera (28MID+).

Table D-11.1 Summary of VOC BACT Determinations for Natural Gas Pipeline Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0874	PORT ARTHUR REFINERY	FUGITIVES	02/04/2020	Volatile Organic Compounds (VOC)	0		0			28MID LDAR and 28CNTQ.
TX-0878	LNG EXPORT TERMINAL	FUGITIVES	09/15/2022	Volatile Organic Compounds (VOC)	0		0			28 VHP
TX-0887	MIDLAND PLAINS MARKETING TERMINAL	Fugitives	04/07/2020	Volatile Organic Compounds (VOC)	0		0			The site-wide fugitive emissions are less than 10 tpy uncontrolled VOC emissions. LADR program and emission reduction credit is not applied.
TX-0892	NEDERLAND TERMINAL	fugitives	07/13/2020	Volatile Organic Compounds (VOC)	0		0			28-VHP LDAR fugitive
TX-0909	POLYETHYLENE UNIT 1792	Fugitives	12/08/2020	Volatile Organic Compounds (VOC)	0		0			28VHP
TX-0910	POLYETHYLENE UNIT 1796	FUGITIVES	12/11/2020	Volatile Organic Compounds (VOC)	0		0			28 VHP
TX-0914	BORGER REFINERY	FUGITIVE COMPONENTS	01/21/2021	Volatile Organic Compounds (VOC)	0		0			28VHP
TX-0916	CEDAR BAYOU	FUGITIVE COMPONENTS	02/01/2021	Volatile Organic Compounds (VOC)	0		0			28 VHP
TX-0929	FORMOSA POINT COMFORT PLANT	FUGITIVES	10/15/2021	Volatile Organic Compounds (VOC)	0		0			modified 28VHP LDAR program in VOC service. A more stringent 500ppmv leak definition of 28MID is used. Annual 28CNTA monitoring is voluntarily used.

Table D-11.1 Summary of VOC BACT Determinations for Natural Gas Pipeline Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0930	CENTURION BROWNSVILLE	Fugitive Components	10/19/2021	Volatile Organic Compounds (VOC)	0		0			Leak detection and repair (LDAR) monitoring and directed maintenance in accordance with the 28VHP program. Quarterly instrumental monitoring using a Method 21 gas analyzer.
TX-0936	BILL GREEHEY REFINERY EAST PLANT	REFINERY FUGITIVES	03/29/2022	Volatile Organic Compounds (VOC)	0	MBF/YR	0			28VHP, 28AVO
TX-0937	VALERO CORPUS CHRISTI REFINERY EAST PLANT	FUGITVES	07/20/2023	Volatile Organic Compounds (VOC)	0		0			28VHP & 28AVO
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	AMMONIA FUGITIVES	03/13/2023	Volatile Organic Compounds (VOC)	0		0			28AVO LDAR program
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	DIESEL FUGITIVES	03/13/2023	Volatile Organic Compounds (VOC)	0		0			28PI LDAR
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	NATURAL GAS FUGITIVES	03/13/2023	Volatile Organic Compounds (VOC)	0		0			28AVO LDAR program
TX-0962	POINT COMFORT PLANT	Fugitive Piping Leaks	09/22/2023	Volatile Organic Compounds (VOC)	0		0			A modified version of the 28VHP LDAR program using a 500 ppm leak definition is used. 28CNTA. 28PI specifically for mineral oil service.
WI-0273	SUPERIOR REFINING COMPANY LLC	F1: Fugitive Components	07/15/2022	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Leak Detection and Repair (LDAR)
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	PG02, PG03, and PG11 Pigging Equipment/Operations	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Complying with Leak Detection and Repair (LDAR) Program
WI-0279	CORPORATE/COMPANY NAMEENBRIDGE ENERGY LIMITED PARTNERSHIP -	Process NameF01 Piping Component/Pumping Fugitive	10/02/2017	Volatile Organic Compounds (VOC)	0		0			Complying with Leak Detection and Repair (LDAR) Program
WI-0307	ENBRIDGE SUPERIOR TERMINAL	Piping Component Equipment Leak Fugitive (F01A)	09/22/2021	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Use certified low-leaking valves or fit certified low-leaking valve packing technology on pressure relief piping and leak detection and repair (LDAR) program.
WI-0307	ENBRIDGE SUPERIOR TERMINAL	Temporary Loading (TL01)	09/22/2021	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		See notes.
WI-0311	SUPERIOR REFINING COMPANY LLC	Fugitive Components (F100)	09/27/2019	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Leak Detection and Repair (LDAR)
WI-0315	SUPERIOR REFINING COMPANY LLC	Fugitive components (F100)	10/09/2020	Volatile Organic Compounds (VOC)	0		0	SEE NOTES		Leak Detection and Repair (LDAR)

Table D-11.2 Summary of CO_2e BACT Determinations for Natural Gas Pipeline Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
LA-0316	CAMERON LNG FACILITY	fugitive emissions	02/17/2017	Carbon Dioxide Equivalent (CO_2e)	0		0			Implement a leak detection and repair (LDAR) program to minimize the leak
LA-0331	CALCASIEU PASS LNG PROJECT	Fugitive Equipment Leaks	09/21/2018	Carbon Dioxide Equivalent (CO_2e)	0		3141	T/YR	ANNUAL TOTAL	Proper piping design.
LA-0383	LAKE CHARLES LNG EXPORT TERMINAL	Fugitives (FUG0001)	09/03/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Proper piping design and LDAR
TX-0759	PORT ARTHUR REFINERY	Hydrocracking and Hydro-treating Fugitive Components	07/31/2015	Carbon Dioxide Equivalent (CO_2e)	105	K BBL/DAY	500	PPMV		Enhanced Fugitive Leak Detection and Repair (LDAR) program that requires quarterly monitoring of valves, pumps, and compressor seals with a leak definition of 500 ppmv. Enhancements to the LDAR program include: 1) Monitoring to be done with data loggers capable of assigning time stamps to individual monitoring events; 2) Repair of leaking components found during weekly physical inspections within 15 days; 3) First attempt of repair of any valve found with a VOC reading greater than 100 ppmv; 4) Conduct of annual training for all of all LDAR technicians in the application of Method 21 consistent with the requirements of the permit; 5) Performance of a third party audit by no later than December 31, 2015 and then at least once every two years thereafter to verify whether EPA Method 21 is being properly applied; 6) and Initiation of an optical gas imaging (OGI) enhanced monitoring program for equipment leaks at those process units subject to EPA Method 21. In addition to the enhanced program, Motiva has agreed to perform quarterly instrument monitoring on fugitive components in heavy liquid service as well as quarterly instrument monitoring on all connectors with a leak definition of 500
TX-0766	GOLDEN PASS LNG EXPORT TERMINAL	Fugitive Emissions	09/11/2015	Carbon Dioxide Equivalent (CO_2e)	0		2569	TPY		Work practice leak detection and repair program
TX-0790	PORT ARTHUR LNG EXPORT TERMINAL	LNG Export Facility - Natural Gas Fugitive Emissions	02/17/2016	Carbon Dioxide Equivalent (CO_2e)	0		1113	T/YR		Work practice - leak detection and repair program (TCEQ 28 VHP LDAR program)
TX-0801	PL PROPYLENE HOUSTON OLEFINS PLANT	Fugitives	06/24/2016	Carbon Dioxide Equivalent (CO_2e)	0		0			LDAR 28LAER

Table D-11.2 Summary of CO_2e BACT Determinations for Natural Gas Pipeline Fugitives

RBLC ID	Facility	Process Name	Permit Date	Pollutant	Capacity	Capacity Units	Permitted Limit	Units	Averaging Period	Control
TX-0847	VALERO PORT ARTHUR REFINERY	Equipment Leaks/Fugitive Emissions	09/16/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			28 VHP
TX-0851	RIO BRAVO PIPELINE FACILITY	FUGITIVES	12/17/2018	Carbon Dioxide Equivalent (CO_2e)	0		0			28 VHP
TX-0865	EQUISTAR CHEMICALS CHANNELVIEW COMPLEX	FUGITIVES	09/09/2019	Carbon Dioxide Equivalent (CO_2e)	0		0			28LAER & 28PI LDAR
TX-0878	LNG EXPORT TERMINAL	FUGITIVES	09/15/2022	Carbon Dioxide Equivalent (CO_2e)	0		0			28 VHP
TX-0881	EXXONMOBIL BEAUMONT REFINERY	FUGITIVES	01/10/2020	Carbon Dioxide Equivalent (CO_2e)	0		0			Compliance with Refinery MACT fugitives and Texas 28VHP LDAR program.
TX-0914	BORGER REFINERY	FUGITIVE COMPONENTS	01/21/2021	Carbon Dioxide Equivalent (CO_2e)	0		0			28VHP
TX-0939	ORANGE COUNTY ADVANCED POWER STATION	NATURAL GAS FUGITIVES	03/13/2023	Carbon Dioxide Equivalent (CO_2e)	0		0			28AVO LDAR program
TX-0964	NEDERLAND FACILITY	EQUIPMENT FUGITIVES	10/05/2023	Carbon Dioxide Equivalent (CO_2e)	0		0			Good management practice and personal portable CO monitors for leaking detection

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APPENDIX E. BACT SUPPORTING DOCUMENTATION

Docusign Envelope ID: B85FD511-01C6-47AA-9B86-D7DA5EC943F2

Appendix E, Table E-2.1 – Cost Analysis Table of Attachments

EU Name	Reduction Option	Capital Costs	Total Annual Costs	Cost Effectiveness
Aux Boiler	NO_x - SCR	$3,319,387	$327,113	$53,060/ton
	NO_x - SNCR	$1,475,528	$171,195	$41,195/ton

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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

Is the SCR for a new boiler or retrofit of an existing boiler? New Construction

What type of fuel does the unit burn? Natural Gas

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 95.52 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,053 Btu/scf

*HHV value of 1053 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 fuel consumption? 794,639,316 scf/year

Enter the net plant heat input rate (NPHR) 8.2 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

Plant Elevation 895 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})	166	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	0.0036	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})	3	
Number of empty catalyst layers (R_{empty})	1	
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)	UNK	acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	25	Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Gas temperature at the SCR inlet (T)	650	°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	2024				
CEPCI for 2024	800.3	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Reagent ($Cost_{reag}$)	0.293	$/gallon for 29% ammonia*			* $0.293/gallon is a default value for 29% ammonia. User should enter actual value, if known.
Electricity ($Cost_{elect}$)	0.0350	$/kWh			
Catalyst cost ($CC_{replace}$)	227.00	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst			* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00	$/hour (including benefits)*			* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00	hours/day*			* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

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.

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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)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0350	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Site-specific estimate
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,053	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/.	Site-specific estimate
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/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.	
Interest Rate (Percent)	7.5	Default bank prime rate	Site-specific estimate

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) =	HHV x Max. Fuel Rate =	96	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	794,639,316	scf/year	
Actual Annual fuel consumption (Mactual) =		794,639,316	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	0.455	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	3984	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	3.09	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	6.16	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	44,239	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	119.15	/hour	
Residence Time	1/V_{space}	0.01	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)* =	14.2	psia	
Retrofit Factor (RF)	New Construction	0.80		

* 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	0.1380	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})	371.28	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	46	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	53	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	7.3	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	52	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} =	1	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	1	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded to t

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	0.0897

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	49.12	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$3,319,387	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$27,969	in 2024 dollars
Indirect Annual Costs (IDAC) =	$299,143	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$327,113	in 2024 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 =	$16,597 in 2024 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$647 in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$6,849 in 2024 dollars
Annual Catalyst Replacement Cost =		$3,877 in 2024 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}/R_{layer}$) x FWF	
Direct Annual Cost =		$27,969 in 2024 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) =	$1,394 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$297,749 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$299,143 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$327,113 per year in 2024 dollars
NOx Removed =	6 tons/year
Cost Effectiveness =	$53,060 per ton of NOx removed in 2024 dollars

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Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? New Construction

1

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 95.52 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 1,053 Btu/scf

*HHV value of 1053 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 fuel consumption? 794,639,316 scf/year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 8.2 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

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 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, %S, %Ash and cost. 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 Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	12,000	2.4
Sub-Bituminous	0	0.41	5.84	9,000	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

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Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	166	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.036	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.015	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.05	

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019).

Plant Elevation	895	Feet above sea level

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year	2024				
CEPCI for 2024	800.3	Enter the CEPCI value for 2024	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7.5	Percent			
Fuel ($Cost_{fuel}$)	3.35	$/MMBtu*			
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*			
Water ($Cost_{water}$)	0.0042	$/gallon*			
Electricity ($Cost_{elect}$)	0.0350	$/kWh			
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton			

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) =	0.015
Administrative Charges Factor (ACF) =	0.03

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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	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0350	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Site-specific estimate
Fuel Cost ($/MMBtu)	3.35	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	Site-specific estimate
Ash Disposal Cost ($/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,053	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/.	Site-specific estimate
Interest Rate	7.5	Default bank prime rate	Bank prime rate is as of January 2025 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

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SNCR Design Parameters

The following design parameters for the SNCR 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) =	HHV x Max. Fuel Rate =	96	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	794,639,316	scf/year	
Actual Annual fuel consumption (Mactual) =		794,639,316	scf/year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/tplant) =	0.455	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3984	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	60	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	2.09	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	4.16	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	#VALUE!		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.03		
Atmospheric pressure at 895 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	14.2	psia	
Retrofit Factor (RF) =	New Construction	0.84		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	2	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	5	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	0.5	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

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	0.0981

Parameter	Equation	Calculated Value	Units

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Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	0.2	kW/hour	
Water Usage: Water consumption (q_w) =	$(m_{sol}/\text{Density of water}) \times ((C_{stored}/C_{inj}) - 1)$ =	2	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.02	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

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Cost Estimate

Total Capital Investment (TCI)

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$485,869	in 2024 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2024 dollars
Balance of Plant Costs (BOP_{cost}) =	$649,153	in 2024 dollars
Total Capital Investment (TCI) =	$1,475,528	in 2024 dollars

SNCR Capital Costs ($SNCR_{cost}$)

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$485,869	in 2024 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2024 dollars

Balance of Plant Costs (BOP_{cost})

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$649,153	in 2024 dollars

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Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$25,778	in 2024 dollars
Indirect Annual Costs (IDAC) =	$145,413	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$171,192	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$22,133	in 2024 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$3,321	in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$29	in 2024 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$38	in 2024 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$258	in 2024 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2024 dollars
Direct Annual Cost =		$25,778	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$664	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$144,749	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$145,413	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$171,192	per year in 2024 dollars
NOx Removed =	4	tons/year
Cost Effectiveness =	$41,195	per ton of NOx removed in 2024 dollars

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APPENDIX F. SUGGESTED PERMIT MARKUP

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Permit	Permit Type	Activity#	Complete Date	Issuance Date	Summary of Action
V-17-030	Renewal	APE20150005	12/10/2015	6/8/2019	Permit Renewal
	Minor Revision	APE20190003	2/7/2019		Add EUs 55-57
	Minor Revision	APE20190005	3/18/2019		Removed EUs 01 & 02 and supporting equipment
V-17 030 R1	Minor Revision	APE20200004	3/11/2021	7/16/2021	Modified descriptions for EUs 23-28
V-17-030 R2	Significant Revision	TBD			Natural Gas-Fired Combined Cycle Project

Commented [MZ1]: KDAQ - Please include the Administrative Change notification from March 2022 or the 502(b)10 Change notification from April 2022.

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SECTION A - PERMIT AUTHORIZATION

Pursuant to a duly submitted application the Kentucky Energy and Environment Cabinet (Cabinet) hereby authorizes the operation of the equipment described herein in accordance with the terms and conditions of this permit. This permit was issued under the provisions of Kentucky Revised Statutes (KRS) Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any affected facilities without first submitting a complete application and receiving a permit for the planned activity from the permitting authority, except as provided in this permit or in 401 KAR 52:020, Title V Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Cabinet or any other federal, state, or local agency.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emission Unit 3 Indirect Heat Exchanger

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel	Controls
3	Pulverized coal- dry bottom-tangentially-fired indirect heat exchanger	July 19, 1971	5,300 MMBtu/hr	Coal, No. 2 Fuel Oil for startup and stabilization	Pulse Jet Fabric Filter (installed 2015) Low NO_X burners (installed 1992) Wet FGD (installed 2010), SCR (installed 2012) Dry sorbent injection for sulfuric acid mist control (installed 2013) Dry sorbent injection system using powdered activated carbon (installed 2015) Liquid additives for mercury control (installed 2015)

APPLICABLE REGULATIONS:

401 KAR 51:160, *NO_X requirements for large utility and industrial boilers*

~~**401 KAR 51:210**, *CAIR NO_X annual trading program* (See Section K)~~

401 KAR 51:220, *CAIR NO_X ozone season trading program* (See Section K)

401 KAR 51:230, *CAIR SO_2 trading program* (See Section K)

401 KAR 52:060, *Acid rain permits*, incorporating the Federal Acid Rain provisions as codified in **40 CFR Parts 72 to 78** (see Section J)

401 KAR 61:015, *Existing indirect heat exchangers*

401 KAR 63:002, Section 2(4)(yyyy), implementing **40 CFR 63, Subpart UUUUU**, *National Emission Standards for Hazardous Air Pollutants, Coal- and Oil-Fired Electric Utility Steam Generating Units*

40 CFR Part 64, *Compliance Assurance Monitoring*

40 CFR 97, Subpart AAAAA, *CSAPR NO_x Annual Trading Program*

40 CFR 97, Subpart CCCCC, *CSAPR SO_2 Group 1 Trading Program*

40 CFR 97, Subpart ~~GGGGG~~EEEEE, *CSAPR NO_x Ozone Season Group ~~3~~ 2 Trading Program*

Commented [MZ2]: KDAQ - CAIR is no longer applicable.

Commented [WJ3]: KDAQ - See comments in Section L.

ADDITIONAL REQUIREMENTS:

Consent Decree filed on March 17, 2009 in U.S. District Court for the Eastern District of Kentucky, Central Division, Lexington, *United States of America v. Kentucky Utilities Company,* Civil Action No. 5:07-CV-0075-KSF ("Consent Decree").

1. **Operating Limitations:**
   a. The total heat input to the emission unit shall be no greater than 5,300 MMBtu/hr. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 92].

      Compliance Demonstration:
      To demonstrate compliance with this requirement the permittee shall calculate the hourly heat input rate using the hourly mass coal burned rate and weekly composite fuel sampling analysis data collected.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. By no later than December 31, 2012, the permittee shall install an SCR for the emission unit [Consent Decree, Paragraph 5].

c. By no later than December 31, 2010, the permittee shall install an FGD on the emission unit [Consent Decree, Paragraph 19].

d. The permittee shall conduct periodic performance tune-ups of the EGUs, as specified in 40 CFR 63.10021(e)(1) through (9). For the first tune-up, the burner inspection may be performed any time prior to the tune-up or may be delayed until the next scheduled EGU outage provided the requirements of 40 CFR 63.10005 are met. Subsequently, the permittee shall perform an inspection of the burner at least once every 36 calendar months unless the EGU employs neural network combustion optimization during normal operations in which case the permittee shall perform an inspection of the burner and combustion controls at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the tune-up work practice requirements shall be performed within 30 days after the re-start of the affected unit [40 CFR 63.9991(a)(1) referencing Item 1. Of Table 3 to Subpart UUUUU of Part 63, 40 CFR 63.10006(i), and 40 CFR 63.10021(e)].

   i. As applicable, inspect the burner and combustion controls, and clean or replace any components of the burner or combustion controls as necessary upon initiation of the work practice program and at least once every required inspection period. Repair of a burner or combustion control component requiring special order parts may be scheduled as follows [40 CFR 63.10021(e)(1)]:

      1. Burner or combustion control component parts needing replacement that affect the ability to optimize NO_x and CO shall be installed within 3 calendar months after the burner inspection [40 CFR 63.10021(e)(1)(i)].

      2. Burner or combustion control component parts that do not affect the ability to optimize NO_x and CO may be installed on a schedule determined by the operator [40 CFR 63.10021(e)(1)(ii)].

   ii. As applicable, inspect the flame pattern and make any adjustments to the burner or combustion controls necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available, or in accordance with best combustion engineering practice for that burner type [40 CFR 63.10021(e)(2)].

   iii. As applicable, observe the damper operations as a function of mill and/or cyclone loading, cyclone and pulverizer coal feeder loadings, or other pulverizer and coal mill performance parameters, making adjustments and effecting repair to dampers, controls, mills, pulverizers, cyclones, and sensors [40 CFR 63.10021(e)(3)].

   iv. As applicable, evaluate windbox pressures and air proportions, making adjustments and effecting repair to dampers, actuators, controls, and sensors [40 CFR 63.10021(e)(4)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

v. Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly. Such inspection may include calibrating excess O_2 probes and/or sensors, adjusting overfire air systems, changing software parameters, and calibrating associated actuators and dampers to ensure that the systems are operated as designed. Any component out of calibration, in or near failure, or in a state that is likely to negate combustion optimization efforts prior to the next tune-up, should be corrected or repaired as necessary [40 CFR 63.10021(e)(5)].

vi. Optimize combustion to minimize generation of CO and NO_x. This optimization should be consistent with the manufacturer's specifications, if available, or best combustion engineering practice for the applicable burner type. NO_x optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, adjusting combustion zone temperature profiles, and add-on controls such as SCR and SNCR; CO optimization includes burners, overfire air controls, concentric firing system improvements, neural network or combustion efficiency software, control systems calibrations, and adjusting combustion zone temperature profiles [40 CFR 63.10021(e)(6)].

vii. While operating at full load or the predominantly operated load, measure the concentration in the effluent stream of CO and NO_x in ppm, by volume, and oxygen in volume percent, before and after the tune-up adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). The permittee may use portable CO, NO_x, and O_2 monitors for this measurement. EGUs employing neural network optimization systems need only provide a single pre- and post-tune-up value rather than continual values before and after each optimization adjustment made by the system [40 CFR 63.10021(e)(7)].

viii. Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in 40 CFR 63.10021(e)(1) through (e)(9) including [40 CFR 63.10021(e)(8)]:

1. The concentrations of CO and NO_x in the effluent stream in ppm by volume, and oxygen in volume percent, measured before and after an adjustment of the EGU combustion systems [40 CFR 63.10021(e)(8)(i)].

2. A description of any corrective actions taken as a part of the combustion adjustment [40 CFR 63.10021(e)(8)(ii)].

3. The type(s) and amount(s) or fuel used over the 12 calendar months prior to an adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period [40 CFR 63.10021(e)(8)(iii)].

ix. ~~The permittee shall report each instance in which an applicable emissions limit or operating limit in 40 CFR 63, Subpart UUUUU, Tables 1 through 4 were not met or~~

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~~the permittee failed to conduct a required tune-up. These instances are deviations from the requirements of 40 CFR 63, Subpart UUUUU. These deviations shall be reported according to 40 CFR 63.10031~~ Prior to January 1, 2024, report the tune-up date electronically, in a PDF file, in your semiannual compliance report, as specified in 40 CFR 63.10031(f)(4) and (6) and, if requested by the Administrator, in hard copy, as specified in 40 CFR 63.10031(f)(5). On and after January 1, 2024, report the tune-up date electronically in your quarterly compliance report, in accordance with 40 CFR 63.10031(g) and section 10.2 of appendix E to this subpart. The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of this section are completed. [40 CFR 63.10021(e)(9)].

Commented [MZ4]: KDAQ - See 85 FR 55759, Sept. 9, 2020]

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements(l) and (m)** and **6. Specific Reporting Requirements(e)(i)(4)**.

e. The permittee shall be in compliance with the emission limits and operating limits in 40 CFR 63, Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however, for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs, the permittee shall meet the work practice requirements, items 3 and 4, in Table 3 to 40 CFR 63, Subpart UUUUU during periods of startup or shutdown [40 CFR 63.10000(a)].

f. During startup:
   i. Before January 2, 2025, the permittee has the option of complying using either of the following work practice standards in paragraphs (1) and (2) of Item 3 of Table 3 to Subpart UUUUU of Part 63 – Work Practice Standards. On or after January 2, 2025, the permittee may not choose to use paragraph (2) of the definition of startup in § 63.10042 and the following associated work practice standards in paragraph (2) ~~The permittee has the option of complying using either of the following work practice standards~~:
      1. If complying using paragraph (1) of the definition of "startup" in 40 CFR 63.10042, the permittee shall operate all continuous monitoring systems (CMS) during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends with any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the permittee shall use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the unit converts to firing coal, residual oil, or solid oil-derived fuel, the permittee shall engage all of the applicable control technologies except dry scrubber and SCR. The permittee shall start dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee shall comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR 63, Subpart UUUUU. The permittee shall keep records during startup periods. The permittee shall provide reports concerning activities and

Commented [MZ5]: Compare 1/1/2018 to 12/5/2024
eCFR :: 40 CFR Part 63 Subpart UUUUU (Dec. 1, 2024) -- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

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startup periods, as specified in 40 CFR 63.10011(g) and 63.10021(h) and (i). If the permittee elects to use paragraph (2) of the definition of startup in 40 CFR 63.10042, the permittee must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i).

2. If complying using paragraph (2) of the definition of "startup" in 40 CFR 63.10042, the permittee shall operate all CMS during startup. The permittee shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the permittee shall use one or a combination of the clean fuels defined in 40 CFR 63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The permittee shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal, residual oil, or solid oil-derived fuel to the unit. The permittee shall meet the startup period work practice requirements as identified in 40 CFR 63.10020(e) (only allowed before January 2, 2025). Once the unit starts firing coal, residual oil, or solid oil-derived fuel, the permittee shall vent emissions to the main stack(s). The permittee shall comply with the applicable emission limits beginning with the hour after startup ends. The permittee shall engage and operate particulate matter control(s) within 1 hour of first firing coal, residual oil, or solid oil-derived fuel. The permittee shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than 40 CFR 63, Subpart UUUUU that require operation of the control devices.

ii. If the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, the permittee shall comply with the limit at all times; otherwise, the permittee shall comply with the applicable emission limit at all times except for startup and shutdown periods.

iii. The permittee shall collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (e). The permittee shall keep records during startup periods, as provided in 40 CFR ~~63.10031 and~~ 63.10021(h) and 63.10032. The permittee shall provide reports concerning activities and startup periods, as specified in 40 CFR 63.10011(g), 63.10021(i), and 63.10031. If the permittee elect to use paragraph (2) of the definition of startup in 40 CFR 63.10042, the permittee must report the applicable information in 40 CFR 63.10031(c)(5) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1,

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2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) [40 CFR 63.9991(a)(1) referencing Item 3. of Table 3 to Subpart UUUUU of Part 63].

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements(l) and (m)** and **5. Specific Recordkeeping Requirements(n)**.

g. During shutdown: The permittee shall operate all CMS during shutdown (as defined in 40 CFR 63.10042). The permittee shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

   i. While firing coal, residual oil, or solid oil-derived fuel during shutdown, the permittee shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee shall operate controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than 40 CFR 63, Subpart UUUUU and that require operation of the control devices.

   ii. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in 40 CFR 63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

   iii. The permittee shall comply with all applicable emission limits at all times except during startup periods and shutdown periods at which time the permittee shall meet this work practice. The permittee shall collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee shall keep records during shutdown periods, as provided in 40 CFR 63.10032 and 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The permittee shall provide reports concerning activities and shutdown periods, as specified in 40 CFR 63.10011(g), 63.10021(i), and 63.10031 [40 CFR 63.9991(a)(1) referencing Item 4. of Table 3 to Subpart UUUUU of Part 63].

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements(l) and (m)** and **5. Specific Recordkeeping Requirements(n)**

h. At all times, operate and maintain the 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. Determination of whether such

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

operation and maintenance procedures are being used will be based on information available to the EPA 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. [40 CFR 63.10000(b)].

2. Emission Limitations:

a. Emissions shall not exceed 40 percent opacity except:

i. A maximum of 60 percent opacity shall be permissible for not more than 1 six-minute period in any sixty 60 consecutive minutes;

ii. For emissions from an indirect heat exchanger during building a new fire for the period required to bring the boiler up to operating conditions, provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations. [401 KAR 61:015, Section 4(3)]

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use the performance tests required by **3. Testing Requirements(a)**.

b. Particulate matter (PM) emissions shall not exceed 0.128 lb/MMBtu based on a three-hour average [401 KAR 61:015, Section 4(1) and Section 4(4)].

Compliance Demonstration:
Compliance with the limit in **2. Emission Limitations(c)** shall constitute compliance with this limit.

c. The permittee shall continuously operate the PJFF for the emission unit to achieve a PM emission rate no greater than 0.030 lb/MMBtu. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 30A].

Compliance Demonstration:
Compliance with this requirement shall be demonstrated by an annual stack test in accordance with **3. Testing Requirements(b)**. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 30A].

d. Sulfur dioxide (SO_2) emissions from the emission unit shall not exceed 5.15 lb/MMBtu based on a 24-hour average [401 KAR 53:010 and 401 KAR 61:015, Section 5(1)].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a SO_2 CEMS. Compliance with the 5.15 lb/MMBtu limit, based on a 24-hour average, assures compliance with the SO_2 limit in 401 KAR 61:015.

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e. Annually, on a calendar year basis, SO_2 emissions from the emission unit shall not exceed 2,300 tons per calendar year. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 22].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a SO_2 CEMS in accordance with the reference methods in 40 CFR Part 75. The permittee shall not use SO_2 allowances to comply with this limit [Consent Decree, Paragraph 24].

f. The permittee shall commence continuous operation of the FGD so as to achieve and thereafter maintain a **30-day Rolling Average Emission Rate** for SO_2 of no greater than 0.100 lb/MMBtu or a **30-day Rolling Average SO_2 Removal Efficiency** of not lower than 97%. This is a permanent federally-enforceable limit [Consent Decree, Paragraph 20].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a SO_2 CEMS, in accordance with the reference methods in 40 CFR Part 75, upstream and downstream of the wet flue gas desulfurization system. The permittee may not use SO_2 allowances to comply with this limit [Consent Decree, Paragraph 24].

g. Emissions of nitrogen oxides from the emission unit shall not exceed 0.070 lb/MMBtu based on a **30-day Rolling Average Emission Rate** except as otherwise provided herein. If the dispatch (including startup, shutdown, and/or load ramping) of the emission unit requires operation of the unit at a load level that results in flue gas temperature so low that it becomes technically infeasible to continuously operate the SCR, despite best efforts by the permittee to do so, the nitrogen oxide emission rate shall not exceed 0.080 lb/MMBtu on a **30-day Rolling Average Emission Rate** [Consent Decree, Paragraphs 6 and 7].

Compliance Demonstration:
To demonstrate compliance with this requirement the permittee shall use a NO_X CEMS in accordance with the reference methods in 40 CFR Part 75. The calculations to demonstrate compliance with the 0.070 lb/MMBtu NO_X limit does not include dispatch events (startup, shutdown, and/or load ramping). The calculations to demonstrate compliance with the 0.080 lb/MMBtu NO_X limit does include dispatch events. The permittee shall use SCR operational data, as required by **5. Specific Recordkeeping Requirements(f)**, to demonstrate the use of the thirty (30)-day rolling average 0.080 lb/MMBtu limit. The permittee shall not use NO_X allowances to comply with this limit.

h. Emissions of sulfuric acid mist (SAM) from Emission Unit 3 shall not exceed 473.1 tons per year based on a twelve (12)–month rolling total. This is a voluntary federally-enforceable limit to preclude 401 KAR 51:017.

Compliance Demonstration:
To demonstrate compliance with this limit the permittee shall determine monthly SAM

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emissions from Emission Unit 3 and add the total to the previous 11-month SAM emissions total. The permittee shall maintain a log onsite of the 12-month rolling total SAM emissions. Monthly SAM emissions shall be determined by:

i. SAM emissions from fuel oil during startup:

$$SAM_{Fuel\ Oil}\left(\frac{\text{tons}}{\text{month}}\right)=\frac{Fuel\ Oil\ Usage\left(\frac{10^3\ \text{gal}}{\text{month}}\right)\times EF\left(\frac{\text{lb}\ SO_3}{10^3\ \text{gal}}\right)}{2000\left(\frac{\text{lb}}{\text{ton}}\right)}\times 1.225\left(\frac{\text{lb}\ H_2SO_4}{\text{lb}\ SO_3}\right)$$

Where, EF = the most recent AP-42 emission factor, currently 5.7S lb/10^3 gallons, where S is the monthly average weight percent of sulfur in the fuel oil.

ii. SAM emissions from burning coal:

$$SAM_{FGD}=\frac{Heat\ Input_{FGD}\left(\frac{\text{MMBtu}}{\text{month}}\right)\times EF_{FGD}\left(\frac{\text{lb}\ SO_3}{\text{MMBtu}}\right)}{2000\left(\frac{\text{lb}}{\text{ton}}\right)}\times 1.225\left(\frac{\text{lb}\ H_2SO_4}{\text{lb}\ SO_3}\right)$$

Where, EF_{FGD} = the most recent SAM stack test emission factor in lb/MMBtu and *Heat Input*$_{FGD}$ is the total monthly heat input from Emission Units 3 while exiting through the FGD stack. The stack test emission factor will be established according to the testing required by **3. Testing Requirements(c)**.

i. Emissions from Emission Unit 3 shall not exceed the limitations in the table below [40 CFR 63.9991(a)(1) referencing Item 1. of Table 2 to Subpart UUUUU of Part 63]. If the permittee elects to comply with these emission limitations using emissions averaging, emissions averaging shall be conducted according to 40 CFR 63.10009 and 40 CFR 63.10022 (On or after July 6, 2027, the permittee may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit)~~CFR 63.10022~~.

Pollutant	Emission Limit	Compliance Demonstration
PM	Before July 6, 2027: 0.030 lb/MMBtu **OR** 0.30 lb/MWh On or after July 6, 2027, 0.010 lb/MMBtu **OR**	Quarterly stack testing **OR** PM CEMS. [Table 5., Item 1; and Table 7. also 40 CFR 63.10005.]

Commented [MZ6]: KDAQ - 63.10022 is mentioned but not cited.

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (4) of this section.
(1) For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.10009(f) and (g);
(2) For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test. On or after July 6, 2027 you may not use PM CPMS for filterable PM compliance demonstrations unless it is for an IGCC unit;
(3) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies. Since on or after July 6, 2027 you may not use PM CPMS, unless it is for an IGCC unit, for compliance demonstrations with the applicable filterable PM limits, the Table 4 p.m. CPMS operating limits do not apply.
(4) For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 to this subpart.
(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (3) of this section is a deviation.

Commented [MZ7]: KU - Table 5 has been revamped. eCFR :: 40 CFR Part 63 Subpart UUUUU -- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

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Pollutant	Emission Limit	Compliance Demonstration
	0.10 lb/MWh ~~0.030 lb/MMBtu~~ ~~**OR**~~ ~~0.30 lb/MWh~~	
OR		
Total non-Hg HAP Metals	Before July 6, 2027: 0.000050 lb/MMBtu **OR** 0.50 lb/GWh On or after July 6, 2027, 1.7E-5 lb/MMBtu **OR** 0.17 lb/GWh	Quarterly stack testing [Table 5., Item 2; and Table 7. also 40 CFR 63.10005.]
OR [On or after July 6, 2027, the permittee may only demonstrate compliance with the following individual HAP metals emissions limits if you request and receive approval for the use of a non-Hg HAP metals CMS under 40 CFR 63.7(f).]		
All of these: Antimony	Before July 6, 2027: 0.80 lb/TBtu **OR** 0.0080 lb/GWh On or after July 6, 2027: 2.7E-1 lb/TBtu or 2.7E-3 lb/GWh	Quarterly stack testing for each [Table 5., Item 2; and Table 7. also 40 CFR 63.10005.]
Arsenic	Before July 6, 2027: 1.1 lb/TBtu **OR** 0.020 lb/GWh On or after July 6, 2027: 3.7E-1 lb/TBtu or 6.7E-3 lb/GWh	
Beryllium	Before July 6, 2027: 0.20 lb/TBtu **OR** 0.0020 lb/GWh On or after July 6, 2027: 6.7E-2 lb/TBtu or 6.7E-4 lb/GWh	
Cadmium	Before July 6, 2027: 0.30 lb/TBtu	

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Pollutant	Emission Limit	Compliance Demonstration
	OR 0.0030 lb/GWh On or after July 6, 2027: 1.0E-1 lb/TBtu or 1.0E-3 lb/GWh	
Chromium	Before July 6, 2027: 2.8 lb/TBtu **OR** 0.030 lb/GWh On or after July 6, 2027: 9.3E-1 lb/TBtu or 1.0E-2 lb/GWh	
Cobalt	Before July 6, 2027: 0.80 lb/TBtu **OR** 0.0080 lb/GWh On or after July 6, 2027: 2.7E-1 lb/TBtu or 2.7E-3 lb/GWh	
Lead	Before July 6, 2027: 1.2 lb/TBtu **OR** 0.020 lb/GWh On or after July 6, 2027: 4.0E-1 lb/TBtu or 6.7E-3 lb/GWh	
Manganese	Before July 6, 2027: 4.0 lb/TBtu **OR** 0.050 lb/GWh On or after July 6, 2027: 1.3E0 lb/TBtu or 1.7E-2 lb/GWh	
Nickel	Before July 6, 2027: 3.5 lb/TBtu **OR** 0.040 lb/GWh On or after July 6, 2027: 1.2E0 lb/TBtu or 1.3E-2 lb/GWh	
Selenium	Before July 6, 2027: 5.0 lb/TBtu	

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Pollutant	Emission Limit	Compliance Demonstration
	OR 0.060 lb/GWh On or after July 6, 2027: 1.7E0 lb/TBtu or 2.0E-2 lb/GWh	
	AND	
HCl	0.0020 lb/MMBtu **OR** 0.020 lb/MWh	Quarterly stack testing **OR** HCl/HF CEMS. [Table 5., Item 3; and Table 7. also 40 CFR 63.10005.]
	OR	
SO_2	0.20 lb/MMBtu **OR** 1.5 lb/MWh	SO_2 CEMS. [Table 5., Item 3; and Table 7.]
	AND	
Hg	1.2 lb/TBtu, **OR** 0.013 lb/GWh	Hg CEMS. [Table 5., Item 4; and Table 7. also 40 CFR 63.10005.] **OR** Sorbent Trap Monitoring. [Table 5., Item 4; and Table 7. also 40 CFR 63.10005.]

3. Testing Requirements:

a. The permittee shall determine the opacity of emissions from the stack by U.S. EPA Reference Method 9 at least once every 14 operating days, or more frequently if requested by the Division or required by this permit [401 KAR 50:055].

b. The permittee shall conduct a stack test for PM on the stack servicing this unit at least once each calendar year, with each stack test conducted at least 6 months apart. The reference methods and procedures for determining compliance with the PM emission rates shall be those specified in 40 CFR 60, Appendix A, Method 5 (with or without the Method 5 adjustment specified in 40 CFR 63, Subpart UUUUU), 5B, or 17, or an alternative method requested by the permittee, and approved for use by EPA. Each test shall consist of three separate runs performed under representative operating conditions and not during periods of startup, shutdown, or malfunction. The sampling time for each run shall be at least 120 minutes and volume of each run shall be 1.70 dry standard cubic meters (sixty (60) dry standard cubic feet). The permittee shall calculate the PM emission rates from the stack test results in accordance with 40 CFR 60.8(f). This is a permanent federally-enforceable testing requirement [Consent Decree, Paragraph 32 and 401 KAR 50:055].

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c. The permittee shall conduct annual performance tests (at least 180 days apart), operating under the conditions established for **4. Specific Monitoring Requirements(k)**, to determine the SAM emission factor [401 KAR 50:055].

d. During the initial SAM performance testing the permittee established the control device's operating parameters that are used as an indicator of SAM emissions, according to **4. Specific Monitoring Requirements(k)**. There may be short-term exceedances during the testing period required to establish or reestablish the operating parameter indicator ranges. These exceedances will not be considered noncompliance periods since the testing is required to establish a permit requirement. The Test Protocol form required by Section G(5)(a) shall detail the method and monitoring to be used to establish the correlation between the control device operating parameters and SAM emissions. The test report shall detail the results of the correlation testing, including the operating parameter indicator ranges to be used [401 KAR 50:055 and 40 CFR 64.6(c)].

e. If the emission unit reports PM exceedances, or SAM excursions for 5% or more of its operating hours during any calendar quarter, then the permittee shall conduct performance testing for PM or SAM emissions, as applicable, during the following calendar quarter while operating under representative conditions. PM emissions shall be determined according to 40 CFR 60, Appendix A, Method 5 (with or without the Method 5 adjustment specified in 40 CFR 63, Subpart UUUUU), 5B, or 17, or an alternative method approved by EPA. The SAM emission factor shall be re-established according to the method in **3. Testing Requirements(d)**. This requirement may be waived if the permittee can demonstrate to the satisfaction of the Division that the cause of the exceedance has been identified and corrected [40 CFR 64.6].

f. For EGUs using PM CPMS before July 6, 2027, to monitor continuous performance with an applicable emission limit as provided for under 40 CFR 63.10000(c), the permittee shall conduct all applicable performance tests according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007 at least every year. On or after July 6, 2027, the permittee may not use PM CPMS to demonstrate compliance for liquid oil-fired, solid oil-derived fuel-fired and coal-fired EGUs.~~For EGUs using PM CPMS to monitor continuous performance with an applicable emission limit as provided for under 40 CFR 63.10000(c), the permittee shall conduct all applicable performance tests according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007 at least every year~~ [40 CFR 63.10006(a)].

g. For affected units meeting the LEE requirements of 40 CFR 63.10005(h), the permittee shall repeat the performance test once every 3 years (once every year for Hg) according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007. Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur [40 CFR 63.10006(b)]:
   i. For all pollutant emission limits except for Hg, the permittee shall conduct emissions testing quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1) [40 CFR 63.10006(b)(1)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

ii. For Hg, the permittee shall install, certify, maintain, and operate a Hg CEMS or a sorbent trap monitoring system in accordance with 40 CFR 63, Subpart 63, Appendix A, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the permittee shall conduct Hg emissions testing quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1). To reestablish LEE status, 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria is required [40 CFR 63.10006(b)(2)].

h. Except where 40 CFR 63.10006(a) or (b) apply, or where the permittee installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the permittee shall conduct all applicable periodic test for filterable PM, individual, or total HAP metals emission according to Table 5 to 40 CFR 63, Subpart UUUUU, 40 CFR 63.10007, and 40 CFR 63.10000(c), except as otherwise provided in 40 CFR 63.10021(d)(1) [40 CFR 63.10006(c)].

i. Except where 40 CFR 63.10006(b) applies, EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the permittee shall conduct all applicable periodic HCl emissions tests according to Table 5 to 40 CFR 63, Subpart UUUUU and 40 CFR 63.10007 at least quarterly, except as otherwise provided in 40 CFR 63.10021(d)(1) [40 CFR 63.10006(d)].

j. Time between performance tests performed for 40 CFR 63, Subpart UUUUU [40 CFR 63.10006(f)].
   i. Notwithstanding the provisions of 40 CFR 63.10021(d)(1), and the requirements listed in 40 CFR 63.10006(g) and (h), and the requirements of 40 CFR 63.10006(f)(3), the permittee shall complete performance tests for the EGU as follows: [40 CFR 63.10006(f)(1)].
      1. At least 45 calendar days, measured from the test's end date, shall separate performance tests conducted every quarter [40 CFR 63.10006(f)(1)(i)];

      2. For annual testing [40 CFR 63.10006(f)(1)(ii)]:
         A. At least 320 calendar days, measured from the test's end date, shall separate performance tests [40 CFR 63.10006(f)(1)(ii)(A)];

         B. At least 320 calendar days, measured from the test's end date, shall separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests [40 CFR 63.10006(f)(1)(ii)(B)];

         C. At least 230 calendar days, measured from the test's end date, shall separate annual sorbent trap mercury testing for 90-boiler operating day LEE tests and [40 CFR 63.10006(f)(1)(ii)(C)];

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. At least 1,050 calendar days, measured from the test's end date, shall separate performance tests conducted every 3 years [40 CFR 63.10006(f)(1)(iii)].

ii. For units demonstrating compliance through quarterly emission testing, the permittee shall conduct a performance test in the 4th quarter of a calendar year if the EGU has skipped performance tests in the first 3 quarters of the calendar year [40 CFR 63.10006(f)(2)].

iii. If the EGU misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next test period, the permittee shall complete an additional performance test in that period as follows [40 CFR 63.10006(f)(3)]:
1. At least 15 calendar days shall separate two performance tests conducted in the same quarter [40 CFR 63.10006(f)(3)(i)].

2. At least 107 calendar days shall separate two performance tests conducted in the same calendar year [40 CFR 63.10006(f)(3)(ii)].

3. At least 350 calendar days shall separate two performance tests conducted in the same 3 year period [40 CFR 63.10006(f)(3)(iii)].

k. Performance tests conducted for 40 CFR 63, Subpart UUUUU shall be conducted according to 40 CFR 63.10007 and Table 5 to 40 CFR 63, Subpart UUUUU. Notwithstanding these requirements, when Table 5 specifies the use of isokinetic EPA test Method 5, 5I, 5D, 26A, or 29 for a stack test, if concurrent measurement of the stack gas flow rate or moisture content is needed to convert the pollutant concentrations to units of the standard, separate determination of these parameters using EPA test Method 2 or EPA test Method 4 is not necessary. Instead, the stack gas flow rate and moisture content can be determined from data that are collected during the EPA test Method 5, 5I, 5D, 6, 26A, or 29 test (e.g., pitot tube (delta P) readings, moisture collected in the impingers, etc.). For the purposes of the initial compliance demonstration, you may use test data and results from a performance test conducted prior to the date on which compliance is required as specified in § 40 CFR 63.9984, provided that the conditions in paragraphs 63.10005(b)(1) through (6) are fully met [40 CFR 63.10005(b) and 63.10006].

4. Specific Monitoring Requirements:

a. Continuous emission monitoring systems (CEMS) shall be installed, calibrated, maintained, and operated for measuring PM emissions, SO_2 emissions, oxygen or carbon dioxide emissions, and NO_x emissions. The continuous emission monitoring systems shall comply with 401 KAR 61:005, Section 3 and the applicable Performance Specification in 40 CFR 60, Appendix B or 40 CFR 75, Appendix A [401 KAR 61:005, Section 3 and 401 KAR 52:020, Section 10].

b. The permittee shall sample and record the sulfur, ash, and heat content of the coal burned, as fired, on a daily basis. The daily grab samples shall be averaged to determine the

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

weighted average value for each calendar week. Additionally, all sulfur data obtained in a calendar month shall be averaged to determine the weighted average sulfur content for each calendar month [401 KAR 61:015, Section 6(3)].

c. The permittee shall determine the sulfur content of fuel oil used during startup and determine a monthly average based on fuel supplier certification or a fuel contract [401 KAR 52:020, Section 10].

d. The hourly rate of each fuel burned (coal and fuel oil), the average electrical output, and the minimum and maximum hourly generation rate shall be measured and recorded daily [401 KAR 61:015, Section 6(3)].

e. The Division may provide a temporary exemption from the monitoring and reporting requirements of 401 KAR 61:005, Section 3, for a continuous monitoring system during any period of monitoring system malfunction, provided that the permittee shows, to the Division's satisfaction, that the malfunction was unavoidable and is being repaired as expeditiously as practicable [401 KAR 61:005, Section 3(4)].

f. To demonstrate compliance with the SO_2 emission limits, if any 24-hour average SO_2 value exceeds the standard (excluding periods of startup and shutdown), the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and make any necessary repairs or take corrective actions as soon as practicable [401 KAR 52:020, Section 10].

g. The permittee shall monitor and record the date, time, and duration for each startup and shutdown event [401 KAR 52:020, Section 10].

h. The permittee shall monitor the SCR inlet temperature and record the hourly average temperature [401 KAR 52:020, Section 10].

i. The permittee shall monitor the wet FGD pump amps and pH and record the hourly averages [401 KAR 52:020, Section 10].

j. To assure compliance with the PM emission limit for the emission unit, the permittee shall [40 CFR 64.6(c)]:
   i. Install, calibrate, maintain and operate a PM CEMS according to Performance Specification 11 in Appendix B to 40 CFR 60;

   ii. The PM CEMS data shall be continuously monitored and recorded to determine hourly average PM emissions.

k. To assure compliance with the SAM emission limit, the permittee shall:
   i. Install, calibrate, and operate a metering system on the sorbent injection system to monitor the sorbent injection rate (lb/hr). The metering system shall be selected to have an accuracy of approximately ± 10% of the target operating range. Additionally,

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

equipment shall be installed, calibrated, and operated as required by the sorbent injection system manufacturer, to monitor the parameters (e.g. unit load and FGD SO_2 inlet) that will be used to monitor the SAM control device operating parameters established by **3. Testing Requirements (d).**

ii. Install, calibrate, and operate SO_2 CEMS, according to 40 CFR Part 75, at the inlet of the wet FGD and the outlet of the wet FGD stack to determine the average hourly SO_2 removal efficiency for the emission unit. The data shall be averaged to determine the average SO_2 removal efficiency for each operating hour of the day.

iii. Continuously, once every 15 minutes, monitor and record the sorbent injection rate (lb/hr). The data shall be averaged to determine the average hourly rate for each operating hour of the day.

iv. The indicator ranges shall be set during the performance test required by **3. Testing Requirements(d)**. An excursion shall be any hourly average that is outside the indicator range established during the performance test.

v. For each excursion, the permittee shall initiate an investigation, take corrective action, and correct any revealed performance issues in the most expedient manner possible.

vi. The sorbent injection rate monitoring equipment shall be periodically calibrated and inspected, according to manufacturer recommendations, at least annually. Sorbent injection rate (lb/hr) at or above the indicator ranges set during the testing required by **3. Testing Requirements** (d) are an indicator of the SAM emission control levels [40 CFR 64.6(c)].

l. The permittee shall comply with all applicable monitoring requirements of 40 CFR 63.10010, 40 CFR 63.10011, 40 CFR 63.10020, and 40 CFR 63.10021.

m. The permittee shall monitor and collect data according to 40 CFR 63.10020 and the site-specific monitoring plan required by 40 CFR 63.10000(d) [40 CFR 63.10020(a)].

i. The permittee shall operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for ~~periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7)), and~~ required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in your site-specific monitoring plan. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable [40 CFR 63.10020(b)].

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ii. The permittee may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee shall use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associate control system [40 CFR 63.10020(c)].

iii. ~~Except for p~~Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities ~~including, as applicable, calibration checks and required~~excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with monitoring system malfunctions or monitoring system out-of-control periods ~~adjustments, failure to collect required data~~ is a deviation from the monitoring system requirements [40 CFR 63.10020(d)].

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of the heat, sulfur and ash content of each fuel on a weekly basis and determine the average sulfur content of each fuel on a monthly basis [401 KAR 52:020, Section 10].

b. The permittee shall maintain records of the amount and rate each fuel is burned, the average electrical output, and the minimum and maximum hourly generation rate on a daily basis [401 KAR 52:020, Section 10].

c. The permittee shall maintain records of the data collected by the continuous monitoring systems, including data necessary to convert monitoring data to the units of the applicable standard [401 KAR 52:020, Section 10 and 40 CFR 64.6(c)].

d. The permittee shall maintain records of the results of all compliance tests [401 KAR 52:020, Section 10].

e. For each startup and shutdown event, the permittee shall maintain records of the date, time, and duration of each startup and shutdown event. The permittee shall also maintain records of the type of startup event that occurs (cold, warm, hot, etc.). [401 KAR 52:020, Section 10].

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f. The permittee shall maintain records of the SCR, wet FGD, and PJFF operating parameters required to be monitored by **4. Specific Monitoring Requirements(h)** and **(i)** and **7. Specific Control Equipment Requirements (b)** [401 KAR 52:020, Section 10].

g. The permittee shall maintain records regarding the maintenance of the wet FGD, SCR, and PJFF [401 KAR 52:020, Section 10 and 40 CFR 64.6(c)].

h. The permittee shall maintain records of the causes and corrective actions taken associated with any exceedance or excursion identified in **4. Specific Monitoring Requirements(j)** and **(k)** [40 CFR 64.6(c)].

i. If 5 percent or more of a unit's operating hours in a calendar quarter report PM exceedances or SAM excursions, as applicable, in accordance with the compliance assurance monitoring in **4. Specific Monitoring Requirements(j)** and **(k)**, then the permittee shall develop and maintain a quality improvement plan (QIP) according to 40 CFR 64.8 [40 CFR 64.6(c)].

j. The permittee shall keep records according to 40 CFR 63.10032(a)(1) and (2). If required or electing to continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if you elect to use a PM CPMS (unless it is for an IGCC unit, you may only use PM CPMS before July 6, 2027), the permittee must keep the records required under appendix A and/or appendix B and/or appendix C and/or appendix D to this subpart. If the permittee elects to conduct periodic (*e.g.*, quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the permittee must keep records of the applicable data elements under 40 CFR 63.7(g). The permittee must also keep records of all data elements and other information in appendix E to this subpart that apply to the compliance strategy~~emissions, the permittee shall also keep the records required under 40 CFR 63, Subpart UUUUU, Appendix A and/or Appendix B~~ [40 CFR 63.10032(a)].
   i. In accordance with 40 CFR 63.10(b)(2)(xiv), a ~~A~~ copy of each notification ~~and~~ or report submitted to comply with 40 CFR 63, Subpart UUUUU, including all records of all supporting for the ~~documentation supporting any~~ Initial Notifications of ~~or Notification of~~ Compliance Status, ~~or~~ semiannual compliance reports, or quarterly compliance reports submitted ~~according to the requirements in 40 CFR 63.10(b)(2)(xiv)~~ [40 CFR 63.10032(a)(1)].

   ii. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii) [40 CFR 63.10032(a)(2)].

k. For each CEMS and CPMS used for 40 CFR 63, Subpart UUUUU, the permittee shall keep records according to 40 CFR 63.10032(b)(1) through (4) [40 CFR 63.10032(b)].
   i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi) [40 CFR 63.10032(b)(1)].

   ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3) {40 CFR 63.10032(b)(2)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i) [40 CFR 63.10032(b)(3)].

iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period [40 CFR 63.10032(b)(4)].

l. The permittee shall keep the records required in Table 7 to 40 CFR 63, Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit applicable to the unit [40 CFR 63.10032(c)].

m. For each EGU subject to an emission limit, the permittee shall also keep the records in 40 CFR 63.10032(d)(1) through (3) [40 CFR 63.10032(d)].
   i. Records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used [40 CFR 63.10032(d)(1)].

   ii. If non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1) are combusted, the permittee shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2) is combusted, the permittee shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee shall keep a record which documents how the fuel satisfies the requirements of the petition process [40 CFR 63.10032(d)(2)].

   iii. For an EGU that qualifies as LEE under 40 CFR 63.10005(h), the permittee shall keep annual records that document that emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year [40 CFR 63.10032(d)(3)].

n. Regarding startup periods or shutdown periods [40 CFR 63.10032(f)]:
   i. If relying on paragraph (1) of the definition of "startup" in 40 CFR 63.10042 for the EGU, the permittee shall keep records of the occurrence and duration of each startup or shutdown [40 CFR 63.10032(f)(1)].

   ii. If relying on paragraph (2) of the definition of "startup" in 40 CFR 63.10042 for the EGU (only allowed before January 2, 2025), the permittee shall keep records of [40 CFR 63.10032(f)(2)]:
      1. The determination of the maximum possible clean fuel capacity for each EGU [40 CFR 63.10032(f)(2)(i)].

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2. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU [40 CFR 63.10032(f)(2)(ii)].

3. The information required in 40 CFR 63.10020(e) (only allowed before January 2, 2025) [40 CFR 63.10032(f)(2)(iii)].
   A. During each period of startup, the permittee shall record for each EGU [40 CFR 63.10020(e)(1)]:
      I. The date and time that clean fuels being combusted for the purpose of startup begins [40 CFR 63.10020(e)(1)(i)];

      II. The quantity and heat input of clean fuel for each hour of startup [40 CFR 63.10020(e)(1)(ii)];

      III. The gross output for each hour of startup [40 CFR 63.10020(e)(1)(iii)];

      IV. The date and time that non-clean fuel combustion begins and [40 CFR 63.10020(e)(1)(iv)];

      V. The date and time that clean fuels being combusted for the purpose of startup ends [40 CFR 63.10020(e)(1)(v)].

   B. During each period of shutdown, the permittee shall record for each EGU [40 CFR 63.10020(e)(2)]:
      I. The date and time that clean fuels being combusted for the purpose of shutdown begins [40 CFR 63.10020(e)(2)(i)];

      II. The quantity and heat input of clean fuel for each hour of shutdown [40 CFR 63.10020(e)(2)(ii)];

      III. The gross output for each hour of shutdown [40 CFR 63.10020(e)(2)(iii)];

      IV. The date and time that non-clean fuel combustion ends and [40 CFR 63.10020(e)(2)(iv)];

      V. The date and time that clean fuels being combusted for the purpose of shutdown ends [40 CFR 63.10020(e)(2)(v)].

   C. For PM or non-mercury HAP metals work practice monitoring during startup periods, the permittee shall monitor and collect data according to 40 CFR 63.10020(e)(3) and the site-specific monitoring plan required by 40 CFR 63.10010(l) (only allowed before January 2, 2025) [40 CFR 63.10020(e)(3)].

   ~~C.~~D. Except for an EGU that uses PM CEMS or PM CPMS to demonstrate compliance with the PM emissions limit, or that has LEE status for filterable PM or total non-Hg HAP metals for non- liquid oil-fired EGUs (or HAP metals

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emissions for liquid oil-fired EGUs), or individual non-mercury metals CMS (except that unless it is for an IGCC unit, on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations with the applicable filterable PM emissions limits, and the permittee may not purse or continue to use the LEE option for filterable PM, total non-Hg HAP metals, or individual non-Hg HAP metals), the permittee must meet 40 CFR 63.10020(e)(3)(i)(A) through (E). [40 CFR 63.10020(e)(3)(i)]

o. The permittee shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment [40 CFR 63.10032(g)].

p. The permittee shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation [40 CFR 63.10032(h)].

q. The permittee shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown [40 CFR 63.10032(i)].

r. Records kept for 40 CFR 63, Subpart UUUUU shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). As specified in 40 CFR 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). Records can be kept off site for the remaining 3 years [40 CFR 63.10033].

6. Specific Reporting Requirements:

a. For each continuous monitoring system, as applicable, the permittee shall submit, in writing to the cabinet, for every calendar quarter, a written report of excess emissions including the nature and cause of the excess emission, if known, as follows [401 KAR 61:005, Section 3(15), 40 CFR 64.6(c)]. The PM Consent Decree data shall be reported in the Semi-Annual Reports [Consent Decree, Paragraph 36]:

i. The averaging period used for data reporting shall correspond to the averaging period specified in the emission test method used to determine compliance with an emission standard for the applicable pollutant and source category, and quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter;

ii. For PM measurements, the summary shall be based on 24-hour rolling averaging, and 6-hour rolling averaging times OR hourly rolling averages.

iii. For gaseous measurements, the summary shall consist of hourly averages expressed in the units of the applicable standard;

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iv. The permittee shall submit any deviations from the sorbent injection rate (lb/hr) indicator ranges. This data or a negative declaration shall be reported semi-annually;

v. Report in the semi-annual reports deviations or a negative declaration of exceedances of the SO_2 emissions from Unit 3 that are above the 0.100 lb/MMBtu 30-day rolling average emission rate limit and below the 97% 30-day rolling average SO_2 removal efficiency limit;

vi. Except for zero and span checks, the date and time of each hourly period during which the continuous monitoring system was not operating, including proof of continuous monitoring system performance during system repairs and the nature of the repairs of adjustments;

vii. If excess emissions have not occurred and the continuous monitoring systems have not been inoperative, repaired or adjusted, this information shall be included in the report; and

viii. All data must be retained for 5 years, but the source shall maintain a file onsite for a minimum of 2 years from the date of collection of the data or submission to the cabinet of:

1. All information reported in the quarterly summaries; and

2. All other data collected by the continuous monitoring systems, including data necessary to convert monitoring data to the units of the applicable standard.

b. The permittee shall submit in the semi-annual report the following information regarding the compliance assurance monitoring for SAM emissions in **4. Specific Monitoring Requirements(k)**:

i. Number of exceedances or excursions;

ii. Duration of each exceedance or excursion;

iii. Cause of each exceedance or excursion;

iv. Corrective actions taken on each exceedance or excursion;

v. Number of monitoring equipment downtime incidents;

vi. Cause of each monitoring equipment downtime incident; and

vii. Description of actions taken to implement a quality improvement plan (according to the method in 40 CFR 64.8); and upon completion of the quality improvement plan, documentation that the plan was completed and reduced the likelihood of similar excursions or exceedances [40 CFR 64.9(a)].

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c. The permittee shall report exceedances that occur as a result of startup on a semi-annual basis. The report shall include the type of start-up and whether or not the duration of the startup exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the startup exceeded recommended or typical durations [401 KAR 52:020, Section 10].

d. The permittee shall report the SAM emissions 12-month rolling totals on a semi-annual basis according to **Section F – Monitoring, Recordkeeping, and Reporting Requirements** [401 KAR 52:020, Section 10].

e. The permittee must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved. [40 CFR 63.10021(f)]

f. The permittee must report each instance in which you did not meet an applicable emissions limit or operating limit in Tables 1 through 4 to this subpart or failed to conduct a required tune-up. These instances are deviations from the requirements of this subpart. These deviations must be reported according to § 63.10031. [40 CFR 63.10021(g)]

g. The permittee must follow the startup or shutdown requirements as given in Table 3 to this subpart for each coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGU. [40 CFR 63.10021(h)]

   i. The permittee may use the diluent cap and default gross output values, as described in § 63.10007(f), during startup periods or shutdown periods. [40 CFR 63.10021(h)(1)]

   ii. The permittee must operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods. [40 CFR 63.10021(h)(2)]

   iii. The permittee may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in § 63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

emission standard, you shall comply with paragraph (1) of the definition of "startup" in § 63.10042. [40 CFR 63.10021(h)(4)]

h. Before January 2, 2025, if the permittee is relying on paragraph 2 of the definition of startup in 40 CFR 63.10042, the permittee must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the permittee must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i). On or after January 2, 2025, the permittee may not use paragraph 2 of the definition of startup in 40 CFR 63.10042. [40 CFR 63.10021(i)]

i. The permittee must submit each report in 63.10031 that applies. [40 CFR 63.10031(a)]

1. If the permittee is required to (or elect to) monitor Hg emissions continuously, the permittee must meet the electronic reporting requirements of appendix A to this subpart. [40 CFR 63.10031(a)(1)]

2. If the permittee elects to monitor HCl and/or HF emissions continuously, the permittee must meet the electronic reporting requirements of appendix B to this subpart. Notwithstanding this requirement, if the permittee opts to certify your HCl monitor according to Performance Specification 18 in appendix B to part 60 of this chapter and to use Procedure 6 in appendix F to part 60 of this chapter for on-going QA of the monitor, then, on and prior to December 31, 2023, report only hourly HCl emissions data and the results of daily calibration drift tests and relative accuracy test audits (RATAs) performed on or prior to that date; keep records of all of the other required certification and QA tests and report them, starting in 2024. [40 CFR 63.10031(a)(2)]

3. If the permittee elects to monitor filterable PM emissions continuously, the permittee must meet the electronic reporting requirements of appendix C to this subpart. Electronic reporting of hourly PM emissions data shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial PM CEMS correlation test. [40 CFR 63.10031(a)(3)]

4. Before July 6, 2027, if the permittee is elects to demonstrate continuous compliance using a PM CPMS, the permittee must meet the electronic reporting requirements of appendix D to this subpart.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Except for IGCC units, on or after July 6, 2027, the permittee may not use PM CPMS for compliance demonstrations. Electronic reporting of the hourly PM CPMS output shall begin with the later of the first operating hour on or after January 1, 2024; or the first operating hour after completion of the initial performance stack test that establishes the operating limit for the PM CPMS. [40 CFR 63.10031(a)(4)]

5. If the permittee elects to monitor SO2 emission rate continuously as a surrogate for HCl, the permittee must use the ECMPS Client Tool to submit the following information to EPA (except where it is already required to be reported or has been previously provided under the Acid Rain Program or another emissions reduction program that requires the use of part 75 of this chapter): [40 CFR 63.10031(a)(5)]

   A. Monitoring plan information for the SO2 CEMS and for any additional monitoring systems that are required to convert SO2 concentrations to units of the emission standard, in accordance with sections 75.62 and 75.64(a)(4) of this chapter; [40 CFR 63.10031(a)(5)(i)]

   B. Certification, recertification, quality-assurance, and diagnostic test results for the SO2 CEMS and for any additional monitoring systems that are required to convert SO2 concentrations to units of the emission standard, in accordance with section 75.64(a)(5); and [40 CFR 63.10031(a)(5)(ii)]

   C. **Quarterly electronic emissions reports.** The permittee must submit an electronic quarterly report within 30 days after the end of each calendar quarter, starting with a report for the calendar quarter in which the initial 30 boiler operating day performance test begins. Each report must include the following information: [40 CFR 63.10031(a)(5)(iii)]

      a. The applicable operating data specified in section 75.57(b) of this chapter;

      b. An hourly data stream for the unadjusted SO2 concentration (in ppm, rounded to one decimal place), and separate unadjusted hourly data streams for the other parameters needed to convert the SO2 concentrations to units of the standard. (Note: If a default moisture value is used in the emission rate

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

calculations, an hourly data stream is not required for moisture; rather, the default value must be reported in the electronic monitoring plan.);

c. An hourly SO2 emission rate data stream, in units of the standard (i.e., lb/MMBtu or lb/MWh, as applicable), calculated according to 40 CFR 63.10007(e) and (f)(1), rounded to the same precision as the emission standard (i.e., with one leading non-zero digit and one decimal place), expressed in scientific notation. Use the following rounding convention: If the digit immediately following the first decimal place is 5 or greater, round the first decimal place upward (increase it by one); if the digit immediately following the first decimal place is 4 or less, leave the first decimal place unchanged;

d. The results of all required daily quality-assurance tests of the SO2 monitor and the additional monitors used to convert SO2 concentration to units of the standard, as specified in appendix B to part 75 of this chapter; and

e. A compliance certification, which includes a statement, based on reasonable inquiry of those persons with primary responsibility for ensuring that all SO2 emissions from the affected EGUs under this subpart have been correctly and fully monitored, by a responsible official with that official's name, title, and signature, certifying that, to the best of his or her knowledge, the report is true, accurate, and complete. The permittee must submit such a compliance certification statement in support of each quarterly report.

j. You must submit semiannual compliance reports according to the requirements in 40 CFR 63.10031(b)(1) through (5). [40 CFR 63.10031(b)]

1.The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)) and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

CFR 63.6(i)(4)). [40 CFR 63.10031(b)(1)]

2. The first compliance report must be submitted electronically no later than July 31 or January 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 40 CFR 63.9984 (or, if applicable, the extended compliance date approved under 40 CFR 63.6(i)(4)). [40 CFR 63.10031(b)(2)]

3. 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. [40 CFR 63.10031(b)(3)]

4. Each subsequent compliance report must be submitted electronically no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. [40 CFR 63.10031(b)(4)]

5. For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, 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), through the reporting period that ends December 31, 2023, 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 (4) of this section. [40 CFR 63.10031(b)(5)]

6. The final semiannual compliance report shall cover the reporting period from July 1, 2023, through December 31, 2023. Quarterly compliance reports shall be submitted thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024. [40 CFR 63.10031(b)(6)]

~~d.~~

~~c.~~k. The permittee shall submit a semiannual compliance report which shall contain [40 CFR 63.10031(~~a~~c) referencing Item ~~1~~9. of Table 8 to Subpart UUUUU of Part 63]:

i. The compliance report shall contain the information required in 40 CFR 63.10031(c)(1) through (~~9~~10).

1. The information required by the summary report located in 40 CFR 63.10(e)(3)(vi) [40 CFR 63.10031(c)(1)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or the permittee's basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure [40 CFR 63.10031(c)(2)].

3. Indicate whether new types of fuel were burned during the reporting period. If new types of fuel were burned, the permittee shall include the date of the performance test where that fuel was in use [40 CFR 63.10031(c)(3)].

4. Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed [40 CFR 63.10031(c)(4)].

5. If relying on paragraph (2) of the definition of "startup" in 40 CFR 63.10042 for the EGU up through January 2, 2025, for each instance of startup or shutdown the permittee shall [40 CFR 63.10031(c)(5)]:

   A. Include the maximum clean fuel storage capacity and the maximum hourly heat input that can be provided for each clean fuel determined according to the requirements of 40 CFR 63.10032(f) [40 CFR 63.10031(c)(5)(i)].

   B. Include the information required to be monitored, collected, or recorded according to the requirements of 40 CFR 63.10020(e) (only allowed before January 2, 2025) [40 CFR 63.10031(c)(5)(ii)].

   ~~C. If using CEMS to demonstrate compliance with numerical limits, include hourly average CEMS values and hourly average flow values during startup periods or shutdown periods. Use units of milligrams per cubic meter for PM CEMS values, micrograms per cubic meter for Hg CEMS values, and ppmv for HCl, HF, or SO_2 CEMS values. Use units of standard cubic meters per hour on a wet basis for flow values [40 CFR 63.10031(c)(5)(iii)].~~

   ~~D. If using a separate sorbent trap measurement system for startup or shutdown reporting periods, include hourly average mercury concentration values in terms of micrograms per cubic meter [40 CFR 63.10031(c)(5)(iv)].~~

   ~~E. If using a PM CPMS, include hourly average operating parameter values in terms of the operating limit, as well as the operating parameter to PM correlation equation [40 CFR 63.10031(c)(5)(v)].~~

6. Emergency bypass information annually from EGUs with LEE status [40 CFR 63.10031(c)(6)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If stack tests are conducted once every 3 years to maintain LEE status, consistent with 40 CFR 63.10006(b), the date of each stack test conducted during the previous 3 years, a comparison of emission level achieved in each stack test conducted during the previous 3 years to the 50 percent emission limit threshold required in 40 CFR 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions [40 CFR 63.10031(c)(7)].

8. A certification [40 CFR 63.10031(c)(8)].

9. If there was a deviation from any emission limit, work practice standard, or operating limit, the permittee shall also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation [40 CFR 63.10031(c)(9)].

~~9.~~10. If you had any process or control equipment malfunction(s) during the reporting period, you must include the number, duration, and a brief description for each type of malfunction which occurred during the semiannual reporting period which caused or may have caused any applicable emission limitation to be exceeded [40 CFR 63.10031(c)(10)].

l. Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in paragraph (c) of this section must include the excess emissions and monitor downtime summary report described in 40 CFR 63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR 63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and you must, instead, include in the quarterly compliance reports described in paragraph (g) of this section the applicable data elements in section 13 of appendix E to this subpart for any "deviation" (as defined in 40 CFR 63.10042 and elsewhere in this subpart) that occurred during the calendar quarter. If there were no deviations, you must include a statement to that effect in the quarterly compliance report~~If there are no deviations from any emission limitation (emission limit and operating limit) applicable to the EGU and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR 63, Subpart UUUUU, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out of control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out of control during the reporting period~~ [40 CFR 63.10031(~~a~~d)~~ referencing Item 1.b. of Table 8 to Subpart UUUUU of Part 63~~].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

~~ii. .~~

m. Each affected source that has obtained a title V operating permit pursuant to part 70 or part 71 of this chapter 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 semiannual compliance report pursuant to paragraphs (c) and (d) of this section, or two quarterly compliance reports covering the appropriate calendar half pursuant to paragraph (g) of this section, 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(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority~~If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report shall contain the information in 40 CFR 63.10031(d). If there were periods during which the CMSs, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out of control, as specified in 40 CFR 63.8(c)(7), the report shall contain the information in 40 CFR 63.10031(e)~~ [40 CFR 63.10031(~~a~~e)~~ referencing Item 1.c. of Table 8 to Subpart UUUUU of Part 63~~].

n. For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), you must submit a PDF test report in accordance with 40 CFR 63.10031(f)(6), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR 63.10031(g), submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart along with the quarterly compliance report for the calendar quarter in which the test was completed. [40 CFR 63.10031(f)]

1.For each RATA of an Hg, HCl, HF, or SO2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the permittee must submit a PDF test report in accordance with paragraph (f)(6) of this section, no later than 60 days after the date on which the test is completed. For each SO2 or Hg RATA completed on or after January 1, 2024, the permittee must submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

appendix B to this subpart or section 7.2.4 of appendix C to this part, as applicable. [40 CFR 63.10031(f)(1)]

2. If, for a particular EGU or a group of EGUs serving a common stack, the permittee have elected to demonstrate compliance using a PM CEMS, an approved HAP metals CMS, or a PM CPMS (on or after July 6, 2027 you may not use PM CPMS for compliance demonstrations, unless it is for an IGCC unit), the permittee must submit quarterly PDF reports in accordance with paragraph (f)(6) of this section, which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in paragraph (g) of this section. In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CMS, the quarterly compliance reports described in paragraph (g) of this section must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO2, if you have elected to (or are required to) continuously monitor these pollutants. Further, if your EGU or common stack is in an averaging plan, the permittee's quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group. [40 CFR 63.10031(f)(2)]

3. The permittee must submit semiannual compliance reports as required under paragraphs (b) through (d) of this section, ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under section 63.10030(e), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with paragraph (g) of this section, starting with a report covering the first calendar quarter of 2024. [40 CFR 63.10031(f)(4)]

4. All reports required by this subpart not subject to the requirements in paragraphs (f) introductory text and (f)(1) through (4) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. If acceptable to both the Administrator and the owner or operator of an EGU, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraphs (f)

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

introductory text and (f)(1) through (4) of this section in paper format. [40 CFR 63.10031(f)(5)]

5. All reports and notifications described in paragraphs (f) introductory text, (f)(1), (2), and (4) of this section shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements shown in 40 CFR 63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. [40 CFR 63.10031(f)(6)]

~~iii. -~~

o. ~~If there was a malfunction during the reporting period, the compliance report shall 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~~ Starting with a report for the first calendar quarter of 2024, you must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of appendix E to this subpart. For each stack test summarized in the compliance report, you must also submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter [40 CFR 63.10031(g)].

p. On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR 63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each Notification [40 CFR 63.10031(h)].

q. If you have elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, you must include the information in 40 CFR 63.10031(c)(5) in the semiannual compliance report, in a PDF file. If you have elected to use paragraph (2) of the definition of "startup" in 40 CFR 63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, you must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

elements in paragraphs (f)(6)(i) through (xii) of this section must be entered into ECMPS with each startup and shutdown report [40 CFR 63.10031(i)].

r. If you elect to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with this subpart and have begun recording valid data from the PM CEMS prior to November 9, 2020, you must use the ECMPS Client Tool to submit a detailed report of your PS 11 correlation test (see appendix B to part 60 of this chapter) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, you must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, you must submit the PDF report according to section 7.2.4 of appendix C to this subpart. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report [40 CFR 63.10031(j)].

s. If you elect to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, you must submit quarterly reports of your QA/QC activities (e.g., calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in paragraph (f)(6)(i) through (xii) of this section must be entered into ECMPS with the PDF report [40 CFR 63.10031(k)].

~~f.~~t. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. Specific Control Equipment Operating Conditions:

a. The wet FGD and SCR shall be operated to maintain compliance with permitted emission limitations, and in accordance with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. The permittee shall continuously operate the PJFF to maximize PM emission reductions at all times when the unit is in operation, provided that such operation of the PJFF is consistent with the technological limitations, manufacturer's specifications and good engineering and maintenance practices for the PJFF. Except as required during correlation testing under 40 CFR 60, Appendix B, Performance Specification 11, and Quality Assurance Requirements under Appendix F, Procedure 2, the permittee shall, at a minimum:

i. Monitor stack PM CEMS output to ensure that the PJFF is operating properly;

ii. Promptly repair, replace, or remove leaking bags identified through monitoring or inspection; and;

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iii. Inspect the PJFF casing, ductwork, and expansion joins for openings or leakage and make any necessary repairs during the next scheduled Unit outage or unscheduled Unit outage of sufficient length. [Consent Decree, Paragraph 29A and 401 KAR 52:020, Section 10]

c. The permittee shall continuously operate the wet FGD whenever the emission unit is in operation. This is a permanent federally-enforceable operating requirement [Consent Decree, Paragraph 20].

d. The permittee shall continuously operate the existing low NO_x burners and over-fire air for the emission unit. This is a permanent federally-enforceable operating requirement [Consent Decree, Paragraph 8].

~~e. The permittee shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment [40 CFR 63.10023~~10032~~(g)].~~

Commented [MZ9]: KDAQ - This is already referenced above.

f. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 7 and 35 **Fugitive Emissions**

Emission Unit	Description	Construction Commenced	Maximum Operating Rate	Control Equipment
07-1	West Track Hopper	1970	820 tons/hr	Enclosures
07-2	Conveyor A-1	1970	820 tons/hr	Enclosures
~~07-3~~	~~Conveyor E~~	~~1970~~	~~820 tons/hr~~	~~Enclosures~~
07-4	Conveyor F	1970	820 tons/hr	Enclosures
07-5	Conveyor G	1970	820 tons/hr	Enclosures
07-6	Conveyor H	1970	820 tons/hr	Enclosures
~~35~~	~~Paved and Unpaved Roadways~~	~~1957~~	~~35,653 VMT/yr~~	~~Dust Suppression (Wet and/or Chemical)~~

Commented [MZ10]: KDAQ - This unit will be fully shutdown in 2025.

Commented [MZ11]: KDAQ - EU 35 is in its own section in the permit, should we remove it from this location?

APPLICABLE REGULATIONS:
401 KAR 63:010, *Fugitive emissions*

1. **Operating Limitations:**
   a. No person shall cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following [401 KAR 63:010, Section 3(1)]:
      i. Use, where possible, of water or chemicals for control of dust in the demolition of existing building or structures, construction operations, the grading of roads or the clearing of land [401 KAR 63:010, Section 3(1)(a)];

      ii. Application and maintenance of asphalt, oil, water or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts [401 KAR 63:010, Section 3(1)(b)];

      iii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or other similar operations [401 KAR 63:010, Section 3(1)(c)];

      iv. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne [401 KAR 63:010, Section 3(1)(d)];

      v. The maintenance of paved roadways in a clean condition [401 KAR 63:010, Section 3(1)(e)];

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

vi. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water [401 KAR 63:010, Section 3(1)(f)].

b. Discharge of visible fugitive dust emissions beyond the property line is prohibited [401 KAR 63:010, Section 3(2)].

Compliance Demonstration:
The permittee shall demonstrate compliance with these requirements by meeting the requirements of **4. Specific Monitoring Requirements** and **5. Specific Recordkeeping Requirements**.

2. Emission Limitations:
The permittee shall not cause or permit the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate [401 KAR 63:010, Section 2].

3. Testing Requirements:
N/A

4. Specific Monitoring Requirements:

a. The permittee shall monitor actions taken (e.g., ~~water usage for roads,~~ enclosures are in good operating condition) to prevent the discharge of visible fugitive emissions beyond the property line for each unit on a monthly basis [401 KAR 52:020, Section 10].

~~b. The permittee shall monitor the processing rate (tons, VMT, gallons/hr, etc.) for each unit on a monthly basis [401 KAR 52:020, Section 10].~~

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of the actions taken to prevent the discharge of visible fugitive emissions beyond the property line on a monthly basis [401 KAR 52:020, Section 10].

b. The permittee shall maintain records of the processing rate (tons, ~~VMT,~~ gallons/hr, etc.) for each unit on a monthly basis [401 KAR 52:020, Section 10].

c. The permittee shall maintain records regarding the maintenance and use of the air pollution control equipment [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:
See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

7. Specific Control Equipment Operating Conditions:

a. The air pollution control equipment for each emission unit shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 9 **Fugitive Coal Handling Operations**

Emission Unit	Description	Reconstruction Commenced	Maximum Operating Rate (tons/hr)	Control Equipment
9-1	East Track Hopper	1993	820	Partially Underground
9-2	Conveyor A	1993	820	Enclosures
9-3	Conveyor B	1993	1,640	Enclosures
~~9-4~~	~~Conveyor C~~	~~1993~~	~~820~~	~~Enclosures~~
9-5	Conveyor J	1993	1,640	Enclosures
9-6	Coal Stockpile	1993	1,640	Dust Suppression (Wet and Compaction)

Commented [MZ12]: KDAQ - This unit will be fully shutdown in 2025.

APPLICABLE REGULATIONS:
401 KAR 60:005, Section 2(2)(gg), implementing **40 CFR 60, Subpart Y**, *Standards of Performance for Coal Preparation and Processing Plants*

1. **Operating Limitations:**
   N/A

2. **Emission Limitations:**
   The permittee shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal gases which exhibit 20 percent opacity or greater [40 CFR 60.254(a)].

   Compliance Demonstration:
   Compliance shall be demonstrated according to **3. Testing Requirements**.

3. **Testing Requirements:**
   The permittee shall determine opacity on a quarterly basis using U.S. EPA Reference Method 9 of Appendix A-4 and as specified in 40 CFR 60.257(a)(1) through (3) [40 CFR 60.255].

4. **Specific Monitoring Requirements:**
   a. The permittee shall monitor the amount of coal received and processed (tons) on a monthly basis [401 KAR 52:020, Section 10].

   b. The permittee shall inspect the partial enclosure control equipment monthly and make necessary repairs to assure compliance [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of the amount of coal received and processed (tons) on a monthly basis [401 KAR 52:020, Section 10].

   b. The permittee shall maintain records regarding all maintenance of the control equipment for each unit [401 KAR 52:020, Section 10].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c. The permittee shall maintain a log onsite of opacity readings required by **3. Testing Requirements** [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:

a. Semiannually, the permittee shall report all 6-minute average opacities that exceed the applicable standard [401 KAR 52:020, Section 10].

b. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. Specific Control Equipment Operating Conditions:

a. Dust suppression shall be utilized to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 13 and 16 Coal Handling Operations

Emission Unit	Description	Construction Commenced	Maximum Operating Rate (tons/hr)	Control Equipment
~~13-1~~	~~(Conveyor D)~~	~~1956~~	~~820~~	~~Enclosure~~
13-2	Upper Traveling Tripper for Unit 3 (Conveyor K-1)	1970	820	Fabric Filter
13-3	Lower Traveling Tripper for Unit 3 (Conveyor K)	1970	820	Fabric Filter
16	Coal Crushing: Four Crushers and Crusher House	1956	1,640	Wet Scrubber

Commented [MZ13]: KDAQ - This unit will be fully shutdown in 2025.

APPLICABLE REGULATIONS:
401 KAR 61:020, *Existing process operations*

1. **Operating Limitations:**
   N/A

2. **Emission Limitations:**
   a. The permittee shall not emit any continuous emissions into the open air from a control device or stack which is equal to or greater than 40 percent opacity [401 KAR 61:020, Section 3(1)(a)].

      Compliance Demonstration:
      The permittee shall demonstrate compliance according to **3. Testing Requirements**.

   b. Particulate matter emissions shall not exceed the limit determined according to the following table, where P is the process rate in tons/hr and E is the maximum allowable emission rate in lbs/hr.

Process Rate (tons/hr)	Emission Limit (lbs/hr)
$P \leq 0.5$	$E = 2.58$
$0.5 < P \leq 30$	$E = 4.10P^{0.67}$
$P > 30$	$E = 55.0P^{0.11} - 40$

      [401 KAR 61:020, Section 3(2)(a)].

      Compliance Demonstration:
      Each unit is assumed in compliance when the associated control equipment is in operation.

3. **Testing Requirements:**
   The permittee shall perform a qualitative visual observation (lasting at least 6 minutes) of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions are observed, then the permittee shall determine the opacity of emissions

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

by U.S. EPA Reference Method 9 as detailed in 40 CFR 60, Appendix A-4 and initiate an inspection of the control equipment for any necessary repairs [401 KAR 52:020, Section 10].

4. **Specific Monitoring Requirements:**
   The permittee shall monitor the operating rate (tons) and hours of operation for each unit on a monthly basis [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of coal processed (tons) and hours of operation for each unit on a monthly basis [401 KAR 52:020, Section 10].

   b. The permittee shall maintain records regarding all maintenance of the control equipment for each unit [401 KAR 52:020, Section 10].

6. **Specific Reporting Requirements:**
   See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. **Specific Control Equipment Operating Conditions:**
   a. The control equipment for each emission unit (cyclone, fabric filter, wet scrubber) shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

   b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 38 Cooling Tower

Emission Unit	Description	Construction Commenced	Maximum Operating Rate	Control Equipment
38	Cooling Tower 3 (forced draft)	1971	10.37 MMgal/hr	Drift Eliminators

APPLICABLE REGULATIONS:
401 KAR 61:020, *Existing process operations*

1. **Operating Limitations:**
   N/A

2. **Emission Limitations:**
   a. The permittee shall not emit any continuous emissions into the open air from a control device or stack which is equal to or greater than 40 percent opacity [401 KAR 61:020, Section 3(1)(a)].

   b. Particulate matter emissions shall not exceed the limit determined according to the following table, where P is the process rate in tons/hr and E is the maximum allowable emission rate in lbs/hr.

Process Rate (tons/hr)	Emission Limit (lbs/hr)
$P \leq 0.5$	$E = 2.58$
$0.5 < P \leq 30$	$E = 4.10P^{0.67}$
$P > 30$	$E = 55.0P^{0.11} - 40$

   [401 KAR 61:020, Section 3(2)(a)].

   Compliance Demonstration:
   The unit is assumed in compliance with the opacity and particulate matter emission standard when the associated control equipment is in operation.

3. **Testing Requirements:**
   N/A

4. **Specific Monitoring Requirements:**
   The permittee shall monitor the processing rate (gallons/hr) on a monthly basis [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of the processing rate (gallons/hr) on a monthly basis [401 KAR 52:020, Section 10].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. The permittee shall maintain records regarding the maintenance and use of the air pollution control equipment [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:
See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. Specific Control Equipment Operating Conditions:
a. The air pollution control equipment for each emission unit shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 30-34 Limestone Handling

Emission Unit	Description	Construction Commenced	Maximum Operating Rating (tons/hr)	Control Equipment
30	Limestone truck dump station #1	01/01/2008	250	Fabric filter
31	Limestone truck dump station #2	01/01/2008	250	
32	Limestone stacking tube	03/01/2008	500	
33	Limestone reclaim conveyor #1	03/01/2008	500	
34	Limestone reclaim conveyor #2	03/01/2008	500	

APPLICABLE REGULATIONS:
401 KAR 59:010, *New process operations*

401 KAR 60:005, Section 2(2)(qqq) implementing **40 CFR 60, Subpart OOO**, *Standards of Performance for Nonmetallic Mineral Processing Plants*

1. **Operating Limitations:**
   N/A

2. **Emission Limitations:**
   a. Emission Units 32-34 shall meet a PM limit of 0.022 gr/dscf and an opacity limit of 7 percent 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 as required under 40 CFR 60.8 [40 CFR 60.672(a)].

      Compliance Demonstration:
      To demonstrate compliance with this requirement the permittee shall meet the testing requirements in **3. Testing Requirements**. Emission Units 30 and 31 are exempt from these emission limitations [40 CFR 60.672(d)].

   b. The permittee shall not emit any continuous emission into the open air form a control device or stack which is equal to or greater than 20 percent opacity [401 KAR 59:010, Section 3(1)(a)].

      Compliance Demonstration:
      For Emission Units 32-34, compliance shall be demonstrated according to **4. Specific Monitoring Requirements(a)** and **(b)**. For Emission Unit 30 and 31, compliance shall be demonstrated according to **4. Specific Monitoring Requirements (c)**.

   c. Particulate matter emissions shall not exceed the limit determined according to the following table, where P is the process rate in tons/hr and E is the maximum allowable emission rate in lbs/hr.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Process Rate (tons/hr)	Emission Limit (lbs/hr)
$P \leq 0.5$	$E = 2.34$
$0.5 < P \leq 30$	$E = 3.59P^{0.62}$
$P > 30$	$E = 17.31P^{0.16}$

[401 KAR 59:010, Section 3(2)]

Compliance Demonstration
For Emission Units 32-34, these units shall be assumed in compliance when in compliance with **2. Emission Limitations (a)** and **(b).** For Emission Units 30 and 31, compliance shall be assumed when in compliance with **2. Emission Limitations (b)**.

3. Testing Requirements:

a. In conducting the performance tests required by 40 CFR 60.8, for Emission Units 32-34, the permittee shall use as reference methods and procedures the test methods in appendices A-1 through A-7 of 40 CFR Part 60, except as provided in 40 CFR 60.8. The permittee may use the alternative methods and procedures provided in 40 CFR 60.675(e) [40 CFR 60.675(a)].

b. For the initial compliance demonstration required by 40 CFR 60.8, the permittee shall determine compliance with the PM standards using U.S. EPA Reference Method 5 of Appendix A-3 to 40 CFR 60 or U.S. EPA Reference Method 17 of Appendix A-6 to 40 CFR 60. The sample volume shall be at least 60 dscf (1.70 dscm). For U.S. EPA Reference Method 5, if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but not higher than 121°C (250°F), to prevent water condensation on the filter [40 CFR 60.675(b)(1)].

c. For the initial compliance demonstration required by 40 CFR 60.8, the permittee shall determine compliance with the opacity standards using U.S. EPA Reference Method 9 of Appendix A-4 to 40 CFR 60 and the procedures in 40 CFR 60.11 [40 CFR 60.675(b)(2)].

4. Specific Monitoring Requirements:

a. The permittee shall conduct quarterly 30-minute visible emissions inspection using U.S. EPA Reference Method 22 (40 CFR Part 60, Appendix A-7) for each fabric filter. The U.S. EPA Reference Method 22 shall be conducted while the fabric filter is operating. The test is successful if no visible emissions are observed. If any visible emissions are observed, the permittee shall initiate corrective action within 24 hours to return the fabric filter to normal operation. The permittee shall record each U.S. EPA Reference Method 22 test, including the date and any other corrective actions taken, in the logbook required under 40 CFR 60.676(b). The permittee may establish a different fabric filter-specific success level for the visible emissions test (other than no visible emissions) by conducting a PM performance test according to 40 CFR 60.675(b) simultaneously with a U.S. EPA Reference Method 22 to determine what constitutes normal visible emissions from that affected facility's fabric filter when it is in compliance with the applicable PM

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

concentration limit in Table 2 of 40 CFR 60, Subpart OOO. The revised visible emissions success level shall be incorporated into the permit for the affected facility [40 CFR 60.674(c)].

b. As an alternative to the periodic U.S. EPA Reference Method 22 visible emissions inspections, the permittee may use a bag leak detection system. The permittee shall install, operate, and maintain the bag leak detection system according to 40 CFR 60.674(d)(1) through (3) [40 CFR 60.674(d)].

c. A qualitative visual observation of the opacity of emissions from the stack on a weekly basis and maintain a log of the observations. If visible emissions from the stack are present (not including condensed water vapor within the plume), then the opacity shall be determined by U.S. EPA Reference Method 9. If emissions are in excess of the applicable opacity limit, then an inspection of control equipment shall be initiated for any necessary repairs [401 KAR 52:020, Section 10].

d. The permittee shall monitor and record the amount of limestone processed (tons) and hours of operation on a monthly basis [401 KAR 52:020, Section 10].

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of each periodic inspection, including dates and any corrective actions taken, in a logbook (in written or electronic format). The logbook shall be kept onsite and make hard or electronic copies of the logbook available upon request [401 KAR 52:020, Section 10].

b. For each bag leak detection system installed and operated, the permittee shall keep records as specified in 40 CFR 60.676(2)(i) through (iii) (including records of the bag leak detection system output, records of adjustments to the system, and date and time of all bag leak detection system alarms and any corrective actions taken) [401 KAR 52:020, Section 10].

c. The permittee shall maintain records of the qualitative visual observation and any U.S. EPA Reference Method 9 readings performed [401 KAR 52:020, Section 10].

d. The permittee shall maintain records of limestone processed (tons) and hours of operation on a monthly basis [401 KAR 52:020, Section 10].

e. The permittee shall maintain records of all maintenance regarding the control equipment [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:

a. The permittee shall submit written reports of the results of all performance tests conducted to demonstrate compliance, including reports of opacity observations made using U.S. EPA

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Reference Method 9 (40 CFR part 60, appendix A-4) to demonstrate compliance with 40 CFR 60.672(b), (e) and (f) [40 CFR 60.676(f)].

b. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. <u>Specific Control Equipment Operating Conditions</u>:

a. The fabric filter shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 50 CCR Landfill Operations and Haul Trucks

Emission Unit	Description	Construction Commenced	Control Equipment
50	Coal combustion residue disposal system – Landfill and material transport operations	June 2013	Wet Suppression by watering, cleaning and road maintenance

APPLICABLE REGULATION:
401 KAR 63:010, *Fugitive emissions*

1. **Operating Limitations:**
   a. No person shall cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following [401 KAR 63:010, Section 3(1)]:
      i. Use, where possible, of water or chemicals for control of dust in the demolition of existing building or structures, construction operations, the grading of roads or the clearing of land [401 KAR 63:010, Section 3(1)(a)];

      ii. Application and maintenance of asphalt, oil, water or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts [401 KAR 63:010, Section 3(1)(b)];

      iii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or other similar operations [401 KAR 63:010, Section 3(1)(c)];

      iv. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne [401 KAR 63:010, Section 3(1)(d)];

      v. The maintenance of paved roadways in a clean condition [401 KAR 63:010, Section 3(1)(e)];

      vi. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water [401 KAR 63:010, Section 3(1)(f)].

   b. Discharge of visible fugitive dust emissions beyond the property line is prohibited [401 KAR 63:010, Section 3(2)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c. When dust, fumes, gases, mist, odorous matter, vapors, or any combination thereof escape from the landfill or equipment in such a manner and amount as to cause a nuisance or to violate any administrative regulation, the secretary may order that the building or equipment in which processing, handling and storage are done be tightly closed and ventilated in such a way that all air and gases and air or gas-borne material leaving the building or equipment are treated by removal or destruction of air contaminants before discharge to the open air [401 KAR 63:010, Section 3(3)].

d. At all times when in motion, open bodied trucks, operating outside company property, transporting materials likely to become airborne shall be covered. No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway [401 KAR 63:010, Section 4].

Compliance Demonstration:
The permittee shall demonstrate compliance with these requirements by complying with the procedures listed above, posting a 15 mile per hour sign for each road way to enforce speed limit and meeting the requirements of **4. Specific Monitoring Requirements** and **5. Specific Recordkeeping Requirements**.

2. Emission Limitations:
The permittee shall not cause or permit the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate [401 KAR 63:010, Section 2].

3. Testing Requirements:
N/A

4. Specific Monitoring Requirements:

a. The permittee shall monitor actions taken (e.g. water usage for roads, enclosures are in good operating condition) to prevent the discharge of visible fugitive emissions beyond the property line for each unit on a daily basis [401 KAR 52:020, Section 10].

b. The permittee shall monitor the rate of material hauled (tons, VMT, gallons/hr, etc.) for each unit or vehicle on paved and unpaved roadways on a monthly basis [401 KAR 52:020, Section 10].

c. In addition, visual observations shall be made on each weekday (Monday through Friday) to determine if fugitive dust is becoming airborne from associated operations as a result of vehicular traffic or windy conditions on paved and unpaved roadways. If such a condition develops, water or a chemical wetting agent shall be applied to these areas as specified in 401 KAR 63:010.

5. Specific Recordkeeping Requirements:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

a. The permittee shall maintain records of the visual observations and actions taken to prevent the discharge of visible fugitive emissions beyond the property line on a daily basis [401 KAR 52:020, Section 10].

b. The permittee shall maintain records of the processing rate (tons, VMT, gallons/hr, etc.) for each vehicle or unit for paved and unpaved roadways on a monthly basis [401 KAR 52:020, Section 10].

c. Records regarding the maintenance and use of the air pollution control equipment shall be maintained [401 KAR 52:020, Section 10].

d. The permittee shall maintain records of the calculations, on a monthly basis, to determine the fugitive emissions from paved and unpaved roads with all data used in calculations. Emission calculations shall be based on the most current AP-42 emission factors for paved and unpaved roadways for that year [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:
See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. Specific Control Equipment Operating Conditions:
a. The associated air pollution control equipment for the emission unit shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 35 **Paved and Unpaved Roadways**

Description:

Construction Commenced:	1957
Maximum Operating Rate:	~~33,653~~30,420 VMT/yr
Controls:	Dust Suppression (Wet and/or Chemical)

Commented [MZ14]: KDAQ - See revised N form for VMT update.

APPLICABLE REGULATIONS:
401 KAR 63:010, *Fugitive emissions*.

1. **Operating Limitations:**
   a. No person shall cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following [401 KAR 63:010, Section 3(1)]:
      i. Use, where possible, of water or chemicals for control of dust in the demolition of existing building or structures, construction operations, the grading of roads or the clearing of land [401 KAR 63:010, Section 3(1)(a)];

      ii. Application and maintenance of asphalt, oil, water or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts [401 KAR 63:010, Section 3(1)(b)];

      iii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or other similar operations [401 KAR 63:010, Section 3(1)(c)];

      iv. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne [401 KAR 63:010, Section 3(1)(d)];

      v. The maintenance of paved roadways in a clean condition [401 KAR 63:010, Section 3(1)(e)];

      vi. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water [401 KAR 63:010, Section 3(1)(f)].

   b. Discharge of visible fugitive dust emissions beyond the property line is prohibited [401 KAR 63:010, Section 3(2)].

Compliance Demonstration:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

The permittee shall demonstrate compliance with these requirements by meeting the requirements of **4. Specific Monitoring Requirements** and **5. Specific Recordkeeping Requirements**.

2. Emission Limitations:
The permittee shall not cause or permit the discharge of visible fugitive dust emissions beyond the lot line of the property on which the emissions originate [401 KAR 63:010, Section 2].

3. Testing Requirements:
N/A

4. Specific Monitoring Requirements:

a. The permittee shall monitor actions taken (e.g., water and/or chemical usage for roads) to prevent the discharge of visible fugitive emissions beyond the property line on a monthly basis [401 KAR 52:020, Section 10].

b. The permittee shall monitor the processing rate (VMT) on a monthly basis [401 KAR 52:020, Section 10].

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of the actions taken to prevent the discharge of visible fugitive emissions beyond the property line on a monthly basis [401 KAR 52:020, Section 10].

b. The permittee shall maintain records of the processing rate (VMT) on a monthly basis [401 KAR 52:020, Section 10].

c. The permittee shall maintain records regarding the maintenance and use of the air pollution control equipment [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:
See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. Specific Control Equipment Operating Conditions:

a. The air pollution control equipment for each emission unit shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 23-29 Combustion Turbines

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel	Control Equipment
23	Combustion Turbine (Unit 9), Model ABB GT 11N2	11/28/1995	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
24	Combustion Turbine (Unit 10) Model ABB GT 11N2	12/22/1995	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
25	Combustion Turbine (Unit 8) Model ABB GT 11N2	3/1/1996	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
26	Combustion Turbine (Unit 11) Model ABB GT 11N2	5/8/1996	1,368 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection
27	Combustion Turbine (Unit 6), Model ABB GT 24	8/11/1999	1,678 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection when burning oil and low NO_X burners when burning natural gas
28	Combustion Turbine (Unit 7) Model ABB GT 24	8/8/1999	1,678 MMBtu/hr	Natural Gas (Primary) Distillate Fuel Oil (Secondary)* Distillate Fuel Oil (Emergency)	Water injection when burning oil and low NO_X burners when burning natural gas
29	Combustion Turbine (Unit 5) Model ABB GT 11N2	6/8/2001	1,368 MMBtu/hr	Natural Gas	Water injection

*A notification per **1. Operating Limitations d.** shall be submitted prior to the usage of distillate fuel oil as a secondary fuel for non-emergency usage.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of Significant Deterioration of Air Quality*;
401 KAR 52:060, *Acid rain permits,* incorporating the Federal Acid Rain provisions as codified in **40 CFR Parts 72 to 78** (see Section J).
401 KAR 60:005, Section 2(2)(pp), implementing **40 CFR 60, Subpart GG**, *Standards of Performance for Stationary Gas Turbines*;
401 KAR 63:002, Section 2(4)(dddd), implementing **40 CFR 63, Subpart YYYY**, *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*. This regulation applies, but these are existing units [40 CFR 63.6090(a)(1)] and they do not have to meet the requirements of this regulation [40 CFR 63.6090(b)(4)].
401 KAR 51:240, *CSAPR NO_x Annual Trading Program*
401 KAR 51:260, *CSAPR SO_2 Group 1 Trading Program*
40 CFR 97, Subpart ~~GGGGG~~EEEEE, *CSAPR NO_x Ozone Season Group ~~3~~ 2 Trading Program*
40 CFR 75, Appendix E, *Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units*

Commented [WJ15]: KDAQ - See comments in Section L regarding non-applicability of GGGGG with stay of SIP disapproval and implementation of the Interim Final Rule.

1. **Operating Limitations:**
   a. The operating rate for each unit shall not exceed the hourly maximum continuous rating listed above, at ISO standard conditions [401 KAR 51:017].

      Compliance Demonstration:
      To demonstrate compliance with this limit the operating rate shall be calculated from each average hourly fuel usage rate at ISO standard conditions, and corresponding fuel heating value characteristics of the fuel combusted.

   b. The maximum operating hours for each unit shall not exceed 2,500 hours per year based on a 12-month rolling total [401 KAR 51:017].

      Compliance Demonstration:
      To demonstrate compliance with this limit, the 12-month total for each unit shall be calculated monthly and reported semi-annually. The permittee shall maintain onsite a log of each 12-month rolling total.

   c. The permittee shall only operate a combustion turbine on emergency distillate fuel oil if there is an emergency and the primary fuel, natural gas, is unavailable, unless, a notification per **1. Operating Limitations: d.** is submitted [40 CFR 75, Appendix E, Section 2.1.4.3].

   d. Except for reliability tests (non-generation usage) and maintenance activities of the combustion turbines on distillate fuel oil, the permittee shall submit a notification to the Cabinet 60-days prior to switching to distillate fuel oil as a secondary fuel rather than an emergency fuel. All noted emission limits, recordkeeping and reporting requirements while operating on non-emergency distillate fuel oil will apply. Performance tests shall be completed prior to non-emergency usage of the CTs while operating on distillate fuel oil (secondary fuel) [401 KAR 52:020, Section 10].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:

a. Nitrogen oxide emissions from each unit shall not exceed the following values, at 15 percent oxygen on a dry basis:

Emission Unit	Plant Unit ID	NO_X emission limit when burning	
		Natural gas (ppm by volume)	Distillate fuel oil (ppm by volume)
23	9	42	65
24	10	42	65
25	8	42	65
26	11	42	65
27	6	25	42
28	7	25	42
29	5	25	N/A

[401 KAR 51:017 and 40 CFR 60.332(a)]

Compliance Demonstration:

For each unit, the permittee shall demonstrate compliance with this requirement during performance testing by using the emission estimate method in 40 CFR 75, Appendix E. Emission rates determined on a pound per million Btu basis shall be converted to parts per million (ppm) using Formula F-5 in 40 CFR 75, Appendix F. These procedures shall be used to identify the acceptable parametric values/ranges against which the data recorded by the continuous monitoring system required by **4. Specific Monitoring Requirements (a)** is compared. Continuous compliance with this requirement is demonstrated via compliance with **4. Specific Monitoring Requirements (a)** and **5. Specific Recordkeeping Requirements (a).**

Commented [AA16]: KDAQ - please refer to Section 5.3.2. of the permit renewal application for a discussion of these requested revisions.

b. These units are exempt from the emission limits in **2. Emission Limitations (a)** when ice fog is deemed a traffic hazard by the permittee [40 CFR 60.332(f)].

Compliance Demonstration:

During the semi-annual reporting required by **Section F – Monitoring, Recordkeeping, and Reporting Requirements**, the permittee shall submit to the Division the date, time, duration and weather conditions that created the hazard.

c. Exemptions from the requirements of **2. Emission Limitations(a)** shall be granted on a case-by-case basis, as determined by the Division, in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions shall be allowed only while the mandatory water restrictions are in effect [40 CFR 60.332(i)].

Compliance Demonstration:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

During the semi-annual reporting required by **Section F – Monitoring, Recordkeeping, and Reporting Requirements**, the permittee shall submit to the Division the date, time, duration and proof of mandatory water restrictions that led to the exemption.

d. The sulfur content of fuel burned and sulfur dioxide emissions shall not exceed the following limits [401 KAR 51:017 and 40 CFR 60.333(b)]:

Emission Unit	Plant Unit ID	Fuel sulfur content		SO_2 Emission (lbs/hr)
		When Emission Units 23-29 are simultaneously operating	For all other operating scenarios	
23	9	0.26%	0.30%	444
24	10	0.26%	0.30%	444
25	8	0.26%	0.30%	444
26	11	0.26%	0.30%	444
27	6	0.23%	0.26%	666
28	7	0.23%	0.26%	666
29	5	0.26%	0.30%	444

Compliance Demonstration:
To demonstrate compliance with the fuel sulfur content limits, the permittee shall determine the fuel sulfur content according to the methods in 40 CFR 75, Appendix D as required by **4. Specific Monitoring Requirements(e)**. The permittee shall be considered in compliance with the SO_2 emission rate limits (lb/hr) when demonstrating compliance with the fuel sulfur content limits.

e. Carbon monoxide emissions from each unit shall not exceed the following limits [401 KAR 51:017]:

Emission Unit	Plant Unit ID	CO (lb/hr)	CO (TPY, based on a 12-month rolling total)
23	9	75	93.8
24	10	75	93.8
25	8	75	93.8
26	11	75	93.8
27	6	112.5	140.63
28	7	112.5	140.63
29	5	75	93.8

Compliance Demonstration:
For each unit, the permittee shall demonstrate compliance using the results of the most recent performance test required by **3. Testing Requirements(b)**. Until a performance test

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

emission factor has been determined, compliance shall be demonstrated using fuel usage rates and the AP-42 emission factor of 10.564 lbs/1000 gal when burning distillate fuel oil and the vendor emission factor of 43 lb/MMscf when burning natural gas.

To demonstrate compliance with the 12-month rolling total emission limit, the 12-month total for each unit shall be calculated monthly and reported semi-annually. The permittee shall maintain onsite a log of each 12-month rolling total.

f. Particulate emissions from each unit shall not exceed the following limits:

Emission Unit	Plant Unit ID	PM (lb/hr)	PM (TPY, based on a 12-month rolling total)
23	9	67	83.8
24	10	67	83.8
25	8	67	83.8
26	11	67	83.8
27	6	100.5	125.63
28	7	100.5	125.63
29	5	67	83.8

[401 KAR 51:017]

Compliance Demonstration:
For each unit, the permittee shall demonstrate compliance using the results of the most recent performance test required by **3. Testing Requirements(a, b, or c)**. Until the performance test emission factor has been determined, the permittee shall demonstrate compliance by using the hourly fuel usage rate and the vendor emission factor of 6.38 lbs/1000 gallon when burning distillate fuel oil or the AP-42 emission factor of 6.73 lbs/MMscf when burning natural gas. To demonstrate compliance with 12-month rolling total emission limit, the 12-month total for each unit shall be calculated monthly and reported semi-annually. The permittee shall maintain onsite a log of each 12-month rolling total.

g. VOC emissions from each unit shall not exceed:

Emission Unit	Plant Unit ID	VOC (lb/hr)	VOC (TPY, based on a 12-month rolling total)
23	9	20.4	25.5
24	10	20.4	25.5
25	8	20.4	25.5
26	11	20.4	25.5

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit	Plant Unit ID	VOC (lb/hr)	VOC (TPY, based on a 12-month rolling total)
27	6	30.6	38.25
28	7	30.6	38.25
29	5	20.4	25.5

[401 KAR 51:017]

Compliance Demonstration:
For each unit, the permittee shall demonstrate compliance using the results of the most recent performance test required by **3. Testing Requirements(a, b, or c)**. Until the performance test emission factor has been determined, the permittee shall demonstrate compliance by using the hourly fuel usage rate and the vendor emission factor of 1.94 lbs/1000 gallon when burning distillate fuel oil or the AP-42 emission factor of 2.14 lbs/MMscf when burning natural gas. To demonstrate compliance with 12-month rolling total emission limit, the 12-month total for each unit shall be calculated monthly and reported semi-annually. The permittee shall maintain onsite a log of each 12-month rolling total.

h. Beryllium emissions from each unit shall not exceed the following limits [401 KAR 51:017]:

Emission Unit	Plant Unit ID	Be (lb/hr)	Be (TPY, based on a 12-month rolling total)
23	9	3.37E-3	4.21E-3
24	10	3.37E-3	4.21E-3
25	8	3.37E-3	4.21E-3
26	11	3.37E-3	4.21E-3
27	6	5.057E-3	6.35E-3
28	7	5.057E-3	6.35E-3
29	5	3.37E-3	4.21E-3

Compliance Demonstration:
1. For distillate fuel oil:

- For each unit, the permittee shall demonstrate compliance using the results of the most recent performance test required by **3. Testing Requirements(c)**.

- The permittee may use fuel supplier certification or fuel sampling for distillate fuel oil, consistent with the custom fuel monitoring plan in **4. Specific Monitoring**

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Requirements(e). For compliance, the permittee shall assume all beryllium in the fuel is emitted as beryllium.

- To demonstrate compliance with 12-month rolling total emission limit, the 12-month total for each unit shall be calculated monthly and reported semi-annually. The permittee shall maintain onsite a log of each 12-month rolling total.

2. For natural gas: The permittee is assumed to be in compliance with the beryllium limit while burning natural gas.

3. Testing Requirements:

a. The permittee shall conduct performance tests to determine nitrogen oxide and diluent concentration for each unit while operating on natural gas or distillate fuel oil (secondary), if applicable, using either EPA Method 20, ASTM D6522-00, or EPA Method 7E and either EPA Method 3 or 3A in appendix A to 40 CFR Part 60. All performance tests shall conform to the requirements of 40 CFR 60.355. The permittee shall conduct nitrogen oxide performance testing on each unit at least once every 20 calendar quarters, if applicable [40 CFR 60.335(a) and 40 CFR Part 75, Appendix E, Section 2.2].

b. To demonstrate compliance with the limits required by 401 KAR 51:017, for each unit while operating on natural gas, the permittee shall conduct performance tests for carbon monoxide and VOC for each unit, using Method 10 for carbon monoxide and Method 18 or 25 for VOC. Testing for each unit operating on natural gas shall be conducted in conjunction with the nitrogen oxides testing once every 20 calendar quarters. Emission rates shall be determined on a pound per million Btu and pound per hour basis. For compliance demonstration and emission estimates, the permittee shall either (1) interpolate emission rates based on testing results at various load levels or (2) use the highest average emission rate over all load levels [401 KAR 50:055].

c. To demonstrate compliance with the limits required by 401 KAR 51:017, for each unit while operating on distillate fuel oil (secondary fuel); the permittee shall conduct performance tests for carbon monoxide, particulate matter, VOC and beryllium for each unit, using Method 10 for carbon monoxide, Method 5 for particulate matter, Method 18 or 25 for VOC, and Method 104 for beryllium, or equivalents. Beryllium performance tests only need to be conducted if the permittee elects not to demonstrate compliance with the beryllium emission limit through fuel supplier certification or fuel sampling. Testing for each unit shall be conducted in conjunction with the nitrogen oxides testing once every 20 calendar quarters, if applicable. The deadline to test begins from the date of the previous test on distillate fuel oil (secondary). Testing is not required if the unit is operating as distillate fuel oil (emergency) on the deadline to test, but shall be completed prior to operating as distillate fuel oil (secondary). Emission rates shall be determined on a pound per million Btu and pound per hour basis. For compliance demonstration and emission estimates, the permittee shall either (1) interpolate emission rates based on testing results

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at various load levels or (2) use the highest average emission rate over all load levels [401 KAR 50:055].

4. Specific Monitoring Requirements:

a. The permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption rate, hourly average heat input rate at ISO conditions, and the ratio of water or steam to fuel being fired in each unit [40 CFR 60.334(a)].

b. The fuel consumption and the ratio of water or steam to fuel being fired in the unit shall be monitored during the performance test required in **3. Testing Requirements(a)** to establish acceptable values and ranges. The permittee may supplement test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. To meet the parameter monitoring plan requirement (which explains the procedures used to document proper operation of the NO_X emission controls) the permittee has chosen to comply with the NO_X emission measurement methodology in Appendix E to 40 CFR Part 75, by developing and keeping onsite a quality-assurance (QA) plan, as described in Section 2.3 of Appendix E and Section 1.3.6 of Appendix B to 40 CFR Part 75 [40 CFR 60.334(g)].

c. The permittee shall select at least four operating parameters indicative of each unit's NO_X formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the turbine manufacturer's recommendations. Alternatively, the permittee may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. If the turbine uses water or steam injection for NO_X control, the water/fuel or steam/fuel ratio shall be one of these parameters. During the NO_X-heat input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Re-determine the NO_X emission rate-heat input correlation for each fuel after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours [40 CFR 75, Appendix E, Section 2.3.1].

d. When the operating levels of certain parameters exceed the limits specified in **4. Specific Monitoring Requirements(c)**, or where the Division issues a notice requesting retesting because the NO_X emission rate data availability for when the unit operates within all quality assurance/quality control parameters in this section since the last test is less than 90.0 percent, as calculated by the Division, complete retesting of the NO_X emission rate by the earlier of: (1) 30 unit operating days (as defined in 40 CFR 72.2) or (2) 180 calendar days after exceeding the limits or after the date of issuance of a notice from the Division to re-verify the unit's NO_X emission rate. The permittee shall submit test results in accordance

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with 40 CFR 75.60 within 45 days of completing the retesting [40 CFR 75, Appendix E, Section 2.3].

e. The permittee shall continue to use the custom fuel monitoring plan, previously approved and provided in 40 CFR 75, Appendix D, Tables D4-D5 and Sections 2.2.1, 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3. The permittee shall maintain a copy onsite of the chosen monitoring plans for natural gas and distillate fuel oil [40 CFR 60.334(h)(4)].

f. Excluding the startup and shutdown periods, if any average emission value exceeds the hourly limits, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and complete necessary process repairs or take corrective action as soon as practicable [401 KAR 52:020, Section 10].

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of the fuel consumption rates, hourly average heat input rate at ISO conditions, and water or steam to fuel ratios, as determined by the continuous monitoring system [40 CFR 60.334(a)].

b. The permittee shall maintain records of the hours of operation and power output (MW) for each unit on a monthly basis [401 KAR 52:020, Section 10].

c. The permittee shall maintain records of the four (or more) operating parameters selected for the parameter monitoring plan on an hourly basis for each unit. This does not apply for emergency distillate fuel oil [401 KAR 52:020, Section 10].

d. The permittee shall identify the recommended range of quality assurance- and quality control-related operating parameters. The permittee shall keep records of these operating parameters for each hour of unit operation (i.e., fuel combustion). The permittee shall keep a written record of the procedures used to perform NO_X emission rate testing. The permittee shall keep a copy of all data and results from the initial, and from the most recent, NO_X emission rate testing, including the values of quality assurance parameters specified in section 2.3 of Appendix E to 40 CFR Part 75 [40 CFR 75, Appendix B, Section 1.3.6].

e. The permittee shall maintain records of the fuel monitoring plan, including the results of each fuel sampling [401 KAR 52:020, Section 10].

f. The permittee 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 and devices, recorded in a permanent form suitable for inspection [401 KAR 52:020, Section 10].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

g. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the emissions unit, any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative [401 KAR 52:020, Section 10].

h. The permittee shall maintain records regarding all maintenance of the water injection system [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:

a. The permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c) for each unit. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are:

i. For nitrogen oxides, when using water or steam injection (excluding Emission Units 27 and 28 when burning natural gas) [40 CFR 60.334(j)(1)(i)]:

1. An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with the nitrogen oxide limit in, as established during the performance test. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

2. A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

3. Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), and gas turbine load. The permittee does not have to report ambient conditions if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the permittee is not using the ISO correction equation under the provisions of 40 CFR 60.334(b)(1).

ii. For nitrogen oxides from Emission Units 27 and 28 when burning natural gas, the permittee shall use the previously submitted and approved procedure for monitoring NO_X compliance in Appendix E to 40 CFR 75 [40 CFR 60.334(c)].

iii. For sulfur dioxide [40 CFR 60.334(j)(2)]:

1. For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas

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turbine exceeds the applicable value in weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit, or.

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

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

iv. Ice fog: Each period during which an exemption is in effect shall be reported in writing quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter [40 CFR 60.334(j)(3)].

v. Emergency Fuel: Each period during which an exemption provided in 40 CFR 60.332(k) is in effect shall be included in the report required in 40 CFR 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported [40 CFR 60.334(j)(4)].

vi. All reports required under 40 CFR 60.7(c) shall be postmarked by the 30th day following the end of each 6-month period [40 CFR 60.334(j)(4)].

b. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

7. <u>Specific Control Equipment Operating Conditions</u>:

a. The water injection control system shall be operated to maintain compliance with permitted emission limitations, consistent with manufacturer's specifications and standard operating practices [401 KAR 50:055].

b. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 39 **Existing 4SLB SI Emergency RICE**

Description:

Make/Model:	WINCO/ B35CS-17R1D (Dix Dam Crest Gate Emergency Generator)
Construction Commenced:	1970
Maximum Continuous Rating:	40 HP
Fuel:	Gasoline
Controls:	None

APPLICABLE REGULATIONS:

401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*.

1. **Operating Limitations:**
   a. The permittee shall:
      i. Change oil and filter every 500 hours of operation or annually, whichever comes first, or according to an oil analysis program [40 CFR 63:6602 referencing Item 6.a. of Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(j)];

      ii. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary [40 CFR 63.6602 referencing Item 6.b. of Table 2c to Subpart ZZZZ of Part 63];

      iii. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary and [40 CFR 63.6602 referencing Item 6.c. of Table 2c to Subpart ZZZZ of Part 63];

      iv. 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-start emission limitations apply [40 CFR 63:6602 referencing Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(h)].

   b. The permittee shall operate and maintain the stationary RICE according to the manufacturer's emission-related operating and maintenance instructions, or develop and follow the permittee's 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 [40 CFR 63.6625(e) and 40 CFR 63.6640(a) referencing Item 9. of Table 6 to Subpart ZZZZ of Part 63].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c. The permittee shall operate the emergency stationary RICE according to the requirements in 40 CFR 63.6640(f)(1) through (3). In order for the engine to be considered an emergency stationary RICE under 40 CFR 63, Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 63.6640(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 63.6640(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 63, Subpart ZZZZ and shall meet all requirements for non-emergency engines [40 CFR 63.6640(f)].

i. There is no time limit on the use of emergency stationary RICE in emergency situations [40 CFR 63.6640(f)(1)].

ii. The permittee may operate the emergency stationary RICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 63.6640(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 63.6640(f)(2) [40 CFR 63.6640(f)(2) and (f)(2)(i)].

iii. 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 ~~and emergency demand response~~ provided in 40 CFR 63.6640(f)(2). 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 [40 CFR 63.6640(f)(3)].

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d. The permittee shall be in compliance with the emission limitations and operating limitations that apply in 40 CFR 63, Subpart ZZZZ at all times [40 CFR 63.6605(a)].

e. At all times the permittee shall operate and maintain the emission unit, 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 any further efforts to reduce emissions if levels required by 40 CFR 63, Subpart ZZZZ 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,

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source [40 CFR 63.6605(b)].

f. The permittee has the option of utilizing an oil analysis program in order to extend the specified oil change requirement in 40 CFR 63.6602. The oil analysis shall be performed at the same frequency specified for changing the oil in 40 CFR 63.6602. The analysis program shall 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 permittee is not required to change the oil. If any of the limits are exceeded, the permittee shall 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 permittee shall change the oil within 2 business days or before commencing operation, whichever is later. The permittee shall 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 shall be part of the maintenance plan for the engine [40 CFR 63.6625(j)].

2. **Emission Limitations:**
N/A

3. **Testing Requirements:**
Testing shall be conducted at such times as may be requested by the cabinet in accordance with 401 KAR 50:045, Section 4.

4. **Specific Monitoring Requirements:**
   a. The permittee shall install a non-resettable hour meter if one is not already installed [40 CFR 63.6625(f)].

   b. The permittee shall monitor fuel usage (Mgal) and hours of operation on a monthly basis [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall keep records of each notification and report that is submitted, the occurrence and duration of each malfunction of operation or the air pollution control and monitoring equipment, records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii), records of all required maintenance performed on the air pollution control and monitoring equipment, and records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 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 [40 CFR 60.6655(a)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. The permittee shall maintain records of the maintenance conducted on the engine in order to demonstrate that the engine was operated and maintained, including any after-treatment control device, according to the maintenance plan for the engine. [40 CFR 63.6655(e)].

c. The permittee shall keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The permittee shall 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 [40 CFR 63.6655(f)(1)].

d. Records shall be in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1). The permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. The permittee shall 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 40 CFR 63.10(b)(1) [40 CFR 63.6660].

e. The permittee shall maintain records of fuel usage (Mgal) on a monthly basis [401 KAR 52:020, Section 10].

6. <u>Specific Reporting Requirements</u>:

a. The permittee shall report each instance in which the operating limitations have not been met. These instances are deviations from the emission and operating limitation in 40 CFR 63 Subpart ZZZZ and shall be reported according to 40 CFR 63.6650 [40 CFR 63.6640(b)].

b. The permittee shall report each instance in which the requirements of Table 8 to 40 CFR 63 Subpart ZZZZ, that apply, have not been met [40 CFR 63.6640(e)]. The notifications listed in 40 CFR 63.7(b) and (c), 40 CFR 63.8(e), (f)(4) and (f)(6), 40 CFR 63.9(b) through (e), and (g) are not required [40 CFR 63.6645(a)(5)].

c. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 40-44 **Existing CI Emergency RICE <500 HP**

Emission Unit	Description	Manufacture Date	Maximum Continuous Rating (HP)	Fuel	Control Equipment
40	Cummins, Model 3304 (Brown Station Emergency Generator)	2000	135	Diesel	None
41	Caterpillar, Model 3306 (CT5 Emergency Generator)	2000	308		
42	Perkins Engine, Model DP150P3 (CT6 Emergency Generator)	1999	230		
43	Perkins Engine, Model DP150P3 (CT7 Emergency Generator)	1999	230		
44	Cummins, Model 681A5.9-F-1 (CT Area Fire Pump Engine)	1994	208		

APPLICABLE REGULATIONS:
401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**
   a. The permittee shall:
      i. Change oil and filter every 500 hours of operation or annually, whichever comes first, or according to an oil analysis program [40 CFR 63.6602 referencing Item 1.a. of Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(i)];

      ii. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first and replace as necessary [40 CFR 63.6602 referencing Item 1.b. of Table 2c to Subpart ZZZZ of Part 63];

      iii. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary and [40 CFR 63.6602 referencing Item 1.c. of Table 2 to Subpart ZZZZ of Part 63];

      iv. Minimize the engine's time spent at idle 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 non-startup emission limitations apply [40 CFR 63.6602 referencing Table 2c to Subpart ZZZZ of Part 63; and 40 CFR 63.6625(h)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. The permittee shall operate and maintain the stationary RICE according to the manufacturer's emission-related operating and maintenance instructions or the facility's developed 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 [40 CFR 63.6625(e) and 63.6640(a) referencing Item 9. of Table 6 to Subpart ZZZZ of Part 63].

c. The permittee shall operate the emergency stationary RICE according to the requirements in 40 CFR 63.6640(f)(1) through (3). In order for the engine to be considered an emergency stationary RICE under 40 CFR 63, Subpart ZZZZ, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 63.6640(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 63.6640(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 63, Subpart ZZZZ and shall meet all requirements for non-emergency engines [40 CFR 63.6640(f)].

i. There is no time limit on the use of emergency stationary RICE in emergency situations [40 CFR 63.6640(f)(1)].

ii. The permittee may operate the emergency stationary RICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 63.6640(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 63.6640(f)(2) [40 CFR 63.6640(f)(2) and (f)(2)(i)].

iii. 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 ~~and emergency demand response~~ provided in 40 CFR 63.6640(f)(2). 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 [40 CFR 63.6640(f)(3)].

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d. The permittee shall be in compliance with the emission limitations and operating limitations that apply in 40 CFR 63, Subpart ZZZZ at all times [40 CFR 63.6605(a)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

e. At all times the permittee shall operate and maintain the emission unit, 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 any further efforts to reduce emissions if levels required by 40 CFR 63, Subpart ZZZZ 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 [40 CFR 63.6605(b)].

f. The permittee has the option of utilizing an oil analysis program in order to extend the specified oil change requirement in 40 CFR 63.6602. The oil analysis shall be performed at the same frequency specified for changing the oil in 40 CFR 63.6602. The analysis program shall 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 permittee is not required to change the oil. If any of the limits are exceeded, the permittee shall change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the permittee shall change the oil within 2 days or before commencing operation, whichever is later. The permittee shall 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 shall be part of the maintenance plan for the engine. [40 CFR 63.6625(i)]

2. Emission Limitations:
N/A

3. Testing Requirements:
Testing shall be conducted at such times as may be requested by the cabinet in accordance with 401 KAR 50:045, Section 4.

4. Specific Monitoring Requirements:

a. The permittee shall install a non-resettable hour meter if one is not already installed [40 CFR 63.6625(f)].

b. The permittee shall monitor the fuel usage (Mgal) and hours of operation on a monthly basis [401 KAR 52:020, Section 10].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

5. Specific Recordkeeping Requirements:

a. The permittee shall keep records of each notification and report that is submitted, the occurrence and duration of each malfunction of operation or the air pollution control and monitoring equipment, records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii), records of all required maintenance performed on the air pollution control and monitoring equipment, and records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 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 [40 CFR 60.6655(a)].

b. The permittee shall maintain records of the maintenance conducted on the engine in order to demonstrate that the engine was operated and maintained, including any after-treatment control device, according to the maintenance plan for the engine. [40 CFR 63.6655(e)].

c. The permittee shall keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The permittee shall 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 [40 CFR 63.6655(f)(1)].

d. Records shall be in a form suitable and readily available for expeditious review according to 40 CFR 63.10(b)(1). The permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. The permittee shall 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 40 CFR 63.10(b)(1) [40 CFR 63.6660].

e. The permittee shall maintain records of fuel usage (Mgal) on a monthly basis [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:

a. The permittee shall report each instance in which the permittee did not meet an applicable operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to 40 CFR 63, Subpart ZZZZ. These instances are deviations from the emission and operating limitations in 40 CFR 63, Subpart ZZZZ and shall be reported according to 40 CFR 63.6650 [40 CFR 63.6640(b)].

b. The permittee shall report each instance in which the requirements of Table 8 to 40 CFR 63 Subpart ZZZZ, that apply, have not been met [40 CFR 63.6640(e)]. The notifications listed in 40 CFR 63.7(b) and (c), 40 CFR 63.8(e), (f)(4) and (f)(6), 40 CFR 63.9(b) through (e), and (g) are not required [40 CFR 63.6645(a)(5)].

c. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 45-~~46~~ 48 New CI Emergency Fire Pump RICE

Emission Unit	Description	Model Year	Maximum Continuous Rating (HP)	Fuel	Control Equipment
45	John Deere, Model 6081HF001, 8.1 L displacement per cylinder (Steam Plant Emergency Fire Pump Engine #1)	April 2007	375	Diesel	None
46	John Deere, Model 6081HF001, 8.1 L displacement per cylinder (Steam Plant Emergency Fire Pump Engine #2)				
47	John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement; equipped with Clarke Fire Pump Engine – Model JX6H-UF50 (FGD Emergency Quench Water/Fire Pump Engine #1)	2007	485 (362 kW)	Diesel	None
48	John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement; equipped with Clarke Fire Pump Engine – Model JX6H-UF50 (FGD Emergency Quench Water/Fire Pump Engine #2)				

Commented [AA19]: KDAQ - please move EU47 and EU48 here per April 2022 Section 502(b)(10) change notification.

APPLICABLE REGULATIONS:

401 KAR 60:005, Section 2(2)(lll), implementing **40 CFR 60, Subpart IIII**, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**
   a. The permittee shall meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII [40 CFR 63.6590(c)(7)].

   b. The permittee shall use diesel fuel certified to the standards in 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 [40 CFR 60.4207(b)].

   Compliance Demonstration:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

The permittee shall demonstrate compliance by using fuel supplier certification.

c. The permittee shall operate the emergency stationary ICE according to the requirements in 40 CFR 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing, ~~emergency demand response~~, and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and shall meet all requirements for non-emergency engines [40 CFR 60.4211(f)].

i. There is no time limit on the use of emergency stationary ICE in emergency situations [40 CFR 60.4211(f)(1)].

ii. The permittee may operate the emergency stationary ICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 60.4211(f)(2) [40 CFR 60.4211(f)(2) and (f)(2)(i)].

iii. 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 and emergency demand response provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), 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. The 50 hours per year for nonemergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met [40 CFR 60.4211(f)(3) and (f)(3)(i)]:

1. The engine is dispatched by the local balancing authority or local transmission and distribution system operator [40 CFR 60.4211(f)(3)(i)(A)];

2. 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 [40 CFR 60.4211(f)(3)(i)(B)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines [40 CFR 60.4211(f)(3)(i)(C)].

4. The power is provided only to the facility itself or to support the local transmission and distribution system [40 CFR 60.4211(f)(3)(i)(D)].

5. The permittee 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 permittee [40 CFR 60.4211(f)(3)(i)(E)].

2. Emission Limitations:

The permittee shall comply with the following emission standards for EU 45 and 46:

Pollutant	Emission Standard
NMHC + NO_X	7.8 g/HP-hr
CO	2.6 g/HP-hr
PM	0.40 g/HP-hr

[40 CFR 60.4205(c)]

The permittee shall comply with the following emission standards for EU 63:

Pollutant	Emission Standard
NMHC + NO_X	3.0 g/HP-hr
CO	2.6 g/HP-hr
PM	0.15 g/HP-hr

[40 CFR 60.4205(c)]

Compliance Demonstration:

a. The permittee shall demonstrate compliance with the emission standards by purchasing an engine certified to the emission standards listed above. The engine shall be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). In the absence of certification from the manufacturer, the permittee shall maintain records of performances tests conducted on the engines, or similar engines, which demonstrate the engines meet the emission standards and that the testing was conducted according to **3. Testing Requirements** [40 CFR 60.4211(c) and 401 KAR 52:020, Section 10].

b. The permittee shall operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer, over the entire life of the

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

engine. In addition, the permittee shall only change those settings that are permitted by the manufacturer. The permittee shall also meet the requirements of 40 CFR Part~~s 89, 94, and/or~~ 1068, as they apply [40 CFR 60.4211(a) and 40 CFR 60.4206].

3. **Testing Requirements:**
   a. Testing shall conform to the requirements of 40 CFR 60.4212(a) through (d), as appropriate [40 CFR 60.4212].

   b. Testing shall be conducted at such times as may be requested by the cabinet in accordance with 401 KAR 50:045, Section 4.

4. **Specific Monitoring Requirements:**
   a. The permittee shall install a non-resettable hour meter prior to startup of the engine [40 CFR 60.4209(a)].

   b. The permittee shall monitor hours of operation and fuel usage (Mgal) on a monthly basis [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records necessary to demonstrate compliance with the applicable emission limits, according to the method specified, and fuel supplier certification according to the applicable fuel requirement. Records of performance tests shall report emission limits and actual emissions in the units of the applicable standard [401 KAR 52:020, Section 10].

   b. The permittee shall maintain records of hours of operation and fuel usage (Mgal) on a monthly basis [401 KAR 52:020, Section 10].

6. **Specific Reporting Requirements:**
   See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units ~~47~~ 49, 51, and 52 New Emergency CI RICE

Emission Unit	Description	Model Year	Maximum Continuous Rating	Fuel	Control Equipment
~~47~~	~~John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement (Emergency Quench Water Pump Engine #1) –Tier 2 engine~~	~~April 2007~~	~~485 HP (362 kW)~~	Diesel	None
~~48~~	~~John Deere, Model 6125HF070; 6 cylinders 12.5 L total displacement (Emergency Quench Water Pump Engine #2) –Tier 2 engine~~	~~April 2007~~	~~485 HP (362 kW)~~		
49	Generac Make: Doosan; Model: 390; 10 cylinder, 18.3 L total displacement –Tier 2, emergency engine	2010	752 HP (561 kW)		
51 & 52	2 Cummins QSK23-G7 NR2, Tier 2 certified emergency engines	2014	1220 HP each		

Commented [MZ20]: KU - Post comment => 47 and 48 should be moved to new fire pump section per 502(b)10 Change.

APPLICABLE REGULATIONS:

401 KAR 60:005, Section 2(2)(lll), implementing **40 CFR 60, Subpart IIII**, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

401 KAR 63:002, Section 2(4)(eeee), implementing **40 CFR 63, Subpart ZZZZ**, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**

~~a. For Emission Units 47 and 48, the permittee shall meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII [40 CFR 63.6590(c)(7)].~~

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b. For Emission Units 49, 51, 52 and 60 the permittee does not have to meet the requirements of 40 CFR 63, Subpart ZZZZ and 40 CFR 63, Subpart A except for the initial notification requirements of 40 CFR 63.6645(f) [40 CFR 63.6590(b)(~~i~~1)].

c. The permittee shall use diesel fuel certified to the standards in 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 [40 CFR 60.4207(b)].

Compliance Demonstration:
The permittee shall demonstrate compliance by using fuel supplier certification.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

d. The permittee shall operate the emergency stationary ICE according to the requirements in 40 CFR 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing, ~~emergency demand response,~~ and operation in nonemergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the engine is not operated according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and shall meet all requirements for non-emergency engines [40 CFR 60.4211(f)].

i. There is no time limit on the use of emergency stationary ICE in emergency situations [40 CFR 60.4211(f)(1)].

ii. The permittee may operate the emergency stationary ICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 60.4211(f)(2) [40 CFR 60.4211(f)(2) and (f)(2)(i)].

iii. 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 and emergency demand response provided in 40 CFR 60.4211(f)(2). Except as provided in 40 CFR 60.4211(f)(3)(i), 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. The 50 hours per year for nonemergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met [40 CFR 60.4211(f)(3) and (f)(3)(i)]:

1. The engine is dispatched by the local balancing authority or local transmission and distribution system operator [40 CFR 60.4211(f)(3)(i)(A)];

2. 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 [40 CFR 60.4211(f)(3)(i)(B)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines [40 CFR 60.4211(f)(3)(i)(C)].

4. The power is provided only to the facility itself or to support the local transmission and distribution system [40 CFR 60.4211(f)(3)(i)(D)].

5. The permittee 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 permittee [40 CFR 60.4211(f)(3)(i)(E)].

2. Emission Limitations:

The permittee shall, for all units, comply with the emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 1039, Appendix I for all pollutants, and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007 [40 CFR 60.4205(b) referencing 40 CFR 60.4202(a)(2)].

Compliance Demonstration:

a. The permittee shall demonstrate compliance with the emission standards by purchasing an engine certified to the emission standards listed above. The engine shall be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). In the absence of certification from the manufacturer, the permittee shall maintain records of performances tests conducted on the engines, or similar engines, which demonstrate the engines meet the emission standards and that the testing was conducted according to **3. Testing Requirements** [40 CFR 60.4211(c) and 401 KAR 52:020, Section 10].

b. The permittee shall operate and maintain the stationary CI ICE and control device according to the manufacturer's written instructions or procedures developed by the permittee that are approved by the engine manufacturer, over the entire life of the engine. In addition, the permittee shall only change those settings that are permitted by the manufacturer. The permittee shall also meet the requirements of 40 CFR Part~~s 89, 94, and/or~~ 1068, as they apply [40 CFR 60.4211(a) and 40 CFR 60.4206].

3. Testing Requirements:

a. Testing shall conform to the requirements of 40 CFR 60.4212(a) through (d), as appropriate [40 CFR 60.4212].

b. Testing shall be conducted at such times as may be requested by the cabinet in accordance with 401 KAR 50:045, Section 4.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a. The permittee shall install a non-resettable hour meter prior to startup of the engine [40 CFR 60.4209(a)].

b. The permittee shall monitor hours of operation and fuel usage (Mgal) on a monthly basis [401 KAR 52:020, Section 10].

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records necessary to demonstrate compliance with the applicable emission limits, according to the method specified, and fuel supplier certification according to the applicable fuel requirement. Records of performance tests shall report emission limits and actual emissions in the units of the applicable standard [401 KAR 52:020, Section 10].

b. The permittee shall maintain records of hours of operation and fuel usage (Mgal) on a monthly basis [401 KAR 52:020, Section 10].

6. Specific Reporting Requirements:

See **Section F – Monitoring, Recordkeeping, and Reporting Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 55-57 Natural Gas Process Heaters

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel
55 (CT NG – 05)	NG Preheater NATCO S832-205D	2003	2.4 MMBtu/hr	Natural Gas
56 (CT NG – 06)	NG Preheater ETI Custom Built	2000	7.0 MMBtu/hr	
57 (CT NG – 07)	NG Preheater ETI Custom Built	2000	7.0 MMBtu/hr	

APPLICABLE REGULATIONS:
401 KAR 59:015, *New indirect heat exchangers*

401 KAR 63:002, Section (2)(4)(iiii), 40 C.F.R. 63.7480 to 63.7575, Tables 1 to 13 (**Subpart DDDDD**), *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*

1. **Operating Limitations:**
   a. For Emission Unit 55, the permittee shall complete a tune-up every 5 years as specified in 40 CFR 63.7540 [40 CFR 63.7500(a)(1) referencing Item 1. of 40 CFR 63, Subpart DDDDD, Table 3; 40 CFR 63.7500(e)].

   b. For Emission Units 56 and 57, the permittee shall complete a tune-up every 2 years as specified in 40 CFR 63.7540 [40 CFR 63.7500(a)(1) referencing Item 2. of 40 CFR 63, Subpart DDDDD, Table 3; 40 CFR 63.7500(e)].

   c. These units shall have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in 40 CFR 63, Subpart DDDDD, Table 3, satisfies the energy assessment requirement. A facility that operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISI 50001 for at least one year between January 1, 2008 and the compliance date specified in 40 CFR 63.7495 that includes the affected units also satisfies the energy assessment requirement. The energy assessment shall include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in 40 CFR 63.7575 [40 CFR 63.7500(a)(1) referencing Item 4. of 40 CFR 63, Subpart DDDDD, Table 3]:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

i. A visual inspection of the boiler or process heater system [40 CFR 63.7500(a)(1) referencing Item 4.a. of 40 CFR 63, Subpart DDDDD, Table 3].

ii. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints [40 CFR 63.7500(a)(1) referencing Item 4.b. of 40 CFR 63, Subpart DDDDD, Table 3].

iii. An inventory of major energy use systems consuming energy from the affected boilers and process heaters and which are under the control of the permittee [40 CFR 63.7500(a)(1) referencing Item 4.c. of 40 CFR 63, Subpart DDDDD, Table 3].

iv. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified [40 CFR 63.7500(a)(1) referencing Item 4.d. of 40 CFR 63, Subpart DDDDD, Table 3].

v. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified [40 CFR 63.7500(a)(1) referencing Item 4.e. of 40 CFR 63, Subpart DDDDD, Table 3].

vi. A list of cost-effective energy conservation measures that are within the facility's control [40 CFR 63.7500(a)(1) referencing Item 4.f. of 40 CFR 63, Subpart DDDDD, Table 3].

vii. A list of the energy savings potential of the energy conservation measures identified [40 CFR 63.7500(a)(1) referencing Item 4.g. of 40 CFR 63, Subpart DDDDD, Table 3].

viii. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments [40 CFR 63.7500(a)(1) referencing Item 4.h. of 40 CFR 63, Subpart DDDDD, Table 3].

d. At all times, the permittee shall 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. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that 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 [40 CFR 63.7500(a)(3)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

e. These units are not subject to the emission limits ~~t~~in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 13, or the operating limits in 40 CFR 63, Subpart DDDDD Table 4 [40 CFR 63.7500(e)].

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f. If the permittee is required to meet an applicable tune-up work practice standard, the permittee shall conduct an annual, biennial, or 5-year performance tune-up according to 40 CFR 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in 40 CFR 63.7540(a)(10) shall be no more than 13 months after the previous tune-up. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) shall be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in 40 CFR 63.7540(a)(12) shall be conducted no more than 61 months after the previous tune-up. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup [40 CFR 63.7515(d) and 63.7540(a)(13)].

g. The permittee shall conduct a tune-up of the boiler or process heater as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. For Emission Unit 55, the permittee may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but the permittee shall inspect each burner at least once every 72 months [CFR 63.7540(a)(11) and 63.7540(a)(12)].

   i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment [40 CFR 63.7540(a)(10)(i)];

   ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available [40 CFR 63.7540(a)(10)(ii)];

   iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection [40 CFR 63.7540(a)(10)(iii)].

   iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_x requirement to which the unit is subject [40 CFR 63.7540(a)(10)(iv)].

   v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

(measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer and [40 CFR 63.7540(a)(10)(v)];

vi. Maintain on-site and submit, if requested by the Administrator, a report containing the information in 40 CFR 63.7540(a)(10)(vi)(A) through (C), [40 CFR 63.7540(a)(10)(vi)]:

1. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater [40 CFR 63.7540(a)(10)(vi)(A)];

2. A description of any corrective actions taken as part of the tune-up and [40 CFR 63.7540(a)(10)(vi)(B)];

3. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may establish the fuel used by each unit [40 CFR 63.7540(a)(10)(vi)(C)].

h. During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 C.F.R. 63.7500 shall meet the work practice standards established in 40 C.F.R. Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii) [401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a)].

2. <u>Emission Limitations</u>:

a. These units are not subject to the emission limits in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 13 [40 CFR 63.7500(e)].

b. The permittee shall not cause emissions of particulate matter in excess of 0.10 lb/MMbtu [401 KAR 59:015, Section 4 (1) (b)].

c. The permittee shall not cause emissions of particulate matter in excess of twenty percent opacity, except [401 KAR 59:015, Section 4 (2)]:

i. A maximum of twenty-seven percent opacity shall be allowed for one six minute period in any sixty consecutive minutes [401 KAR 59:015, Section 4 (2) (a)];

ii. For emissions from an affected facility caused by building a new fire, emissions during the period required to bring the boiler up to operation conditions shall be allowed, is the method used is recommended by the manufacturer and the time does not exceed the manufacturer's recommendations [401 KAR 59:015, Section 4 (2) (c)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

d. The permittee shall not cause emissions of sulfur dioxide in excess of 0.8 lb/MMBtu [401 KAR 59:015, Section 5 (1) (b) 1.].

Compliance Demonstration:
These units are assumed to be in compliance with the applicable 401 KAR 59:015 particulate matter, sulfur dioxide, and opacity standards while burning natural gas [401 KAR 50:045, Section 4(3)(c)1.].

e. See **Section D**, **Source Emission Limitations and Testing Requirements**.

3. Testing Requirements:
Testing shall be conducted at such times as may be requested by the cabinet in accordance with 401 KAR 50:045, Section 4.

4. Specific Monitoring Requirements:
The permittee shall monitor natural gas usage (MMscf) for Emission Units 55-57, on a monthly basis [401 KAR 52:020, Section 10].

5. Specific Recordkeeping Requirements:
a. The permittee shall maintain records of natural gas usage (MMscf) for each Emission Units 55-57, on a monthly basis [401 KAR 52:~~030~~020, Section 10].

b. The permittee shall keep a copy of each notification and report submitted to comply with 40 CFR 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements of 40 CFR 63.10(b)(2)(xiv) [40 CFR 63.7555(a) and 63.7555(a)(1)].

6. Specific Reporting Requirements:
a. The permittee shall report each instance in which an emission limit and operating limit in 40 CFR 63, Subpart DDDDD, Table 3, as applicable, was not met. These instances are deviations from the emission limits or operating limits, respectively, in 40 CFR 63, Subpart DDDDD. These deviations shall be reported according to the requirements in 40 CFR 63.7550 [40 CFR 63.7540(b)].

b. The permittee shall submit the Notification of Compliance Status and shall contain the information specified in 40 CFR 63.7545(e)(1) and (8) and shall be submitted within 60 days of the compliance date specified at 40 CFR 63.7495(b) [40 CFR 63.7545 (e)].
   i. A description of the affected units including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with 40 CFR 63, Subpart DDDDD, description of the fuel burned, including whether the fuel was a secondary material determined by the permittee or the EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel was a secondary material processed from discarded non-hazardous

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

secondary material within the meaning of 40 CFR 241.3, and justification for the selection of fuel burned during the compliance demonstration [40 CFR 63.7545(e)(1)].

ii. In addition to information required in 40 CFR 63.9(h)(2), your notification of compliance status must include the following certifications of compliance, as applicable, and signed by a responsible official [40 CFR 63.7545(e)(8)]:
1. This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in 40 CFR 63.7540(a)(10)(i) through (vi) [40 CFR 63.7545(e)(8)(i)].

2. This facility has had an energy assessment performed according to 40 CFR 63.7530 (e) [40 CFR 63.7545(e)(8)(ii)].

c. The permittee may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4) [40 CFR 70.7550(b)]:
i. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for the source in 40 CFR 63.7495 [40 CFR 63.7550(b)(1)].

ii. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31 [40 CFR 63.7550(b)(2)].

iii. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31 [40 CFR 63.7550(b)(3)].

iv. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31 [40 CFR 63.7550(b)(4)].

b. The permittee shall submit a compliance report with the information in 40 CFR 63.7550 (c) (5) (i) through (iii), (xiv), and (xvii) [40 CFR 63.7550(c)(1)]:
i. Company and Facility name and address [40 CFR 63.7550(c)(5)(i)].

ii. Process unit information, emission limitations, and operating parameter limitations [40 CFR 63.7550(c)(5)(ii)].

iii. Date of report and beginning and ending dates of the reporting period [40 CFR 63.7550(c)(5)(iii)].

iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annual, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown [40 CFR 63.7550(c)(5)(xiv)].

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v. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report [40 CFR 63.7550(c)(5)(xvii)].

c. See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 58 **Lean Premix Natural Gas-Fired Stationary Combined Cycle Combustion Turbine with HRSG/Duct Burners (681 MWg)**

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Description:
Combined cycle operations will consist of one natural gas-fired combustion turbine, a steam turbine, and one heat recovery steam generator (HRSG) with natural gas-fired duct burners arranged in a one-on-one configuration. This emission unit will utilize dry-low-NO_X combustors in the gas turbine and low-NO_X duct burners in the HRSG.

Facility Name:	Unit 12
Make/Model:	GE 7HA.03
Construction Commenced:	June 2026
Maximum Continuous Rating:	4,895 MMBtu/hr for GT and 4,525 MMBtu/hr (HHV) for NGCC
Fuel:	Natural Gas
Controls:	SCR, Dry-Low-NO_X Combustors (DLN), Oxidation Catalyst

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*
401 KAR 52:060, *Acid rain permits,* incorporating the Federal Acid Rain provisions as codified in **40 CFR Parts 72 to 78** (see Section J).
401 KAR 60:005, Section 2(2)(ffff), 40 C.F.R. 60.4300 to 60.4420, Table 1 (**Subpart KKKK**), *Standards of Performance for Stationary Gas Turbines*
40 CFR 60, Subpart TTTTa, *Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units* **[NOTE: Subpart TTTTa is subject to judicial challenge and may change or be vacated. Proposed permit language is not provided];**
401 KAR 63:002, Section 2(4)(dddd), 40 C.F.R. 63.6080 to 63.6175, Tables 1 to 7 (**Subpart YYYY**), *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*
401 KAR 51:240, 40 CFR 97, Subpart AAAAA, *Cross-State Air Pollution Rule (CSAPR) NO_x annual trading program*
401 KAR 51:260, 40 CFR 97, Subpart CCCCC, *Cross-State Air Pollution Rule (CSAPR) SO_2 group 1 trading program*
40 CFR 97, Subpart EEEEE, *CSAPR NO_x Ozone Season Group 2 Trading Program*

ADDITIONAL REQUIREMENT SPECIFICALLY FOR HRSG:
401 KAR 59:015, *New indirect heat exchangers*

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

1. Operating Limitations:

NSPS KKKK

a. The permittee must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. [40 CFR 60.4333(a)].

NESHAP YYYY

b. Equipment covered by 40 CFR 63, Subpart YYYY:

i. Stationary 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 stationary combustion turbine, any regenerative/ recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system (40 CFR 63.6085(a)]

ii. Duct burners and waste heat recovery units are considered steam generating units and are not covered under 40 CFR 63, Subpart YYYY. In some cases, it may be difficult to separately monitor emissions from the turbine and duct burner, so sources are allowed to meet the required emission limitations with their duct burners in operation. [40 CFR 63.6092]

c. As Unit 12 is a new combustion turbine which is a lean premix gas-fired stationary combustion turbine as defined by 40 CFR 63, Subpart YYYY after March 9, 2022, the permittee must comply with the emissions limitations and operating limitations in this 40 CFR 63, Subpart YYYY upon startup of the affected source. [40 CFR 63.6095(a)(4))]

d. As Unit 12 is a new stationary combustion turbine which is a lean premix gas-fired stationary combustion turbine, the permittee must comply with the operating limitations in Table 2 of 40 CFR 63, Subpart YYYY. [40 CFR 63.6100]

i. The period of time for turbine startup is subject to the limits specified in the definition of startup in 40 CFR 63.6175, where startup begins at the first firing of fuel in the stationary combustion turbine. For combined cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 3 hours, whichever is less. Turbines in combined cycle configurations that are operating as simple cycle turbines must meet the startup requirements for simple cycle turbines while operating as simple cycle turbines. [40 CFR 63.6100 and Table 1, Item 1, of 40 CFR 63, Subpart YYYY]

ii. When Unit 12 is using an oxidation catalyst to comply with the formaldehyde

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

emissions limit, the permittee shall maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature. [40 CFR 63.6100 and 63.6140 and Table 2, Item 1, of 40 CFR 63, Subpart YYYY]

e. General requirements for complying with 40 CFR 63, Subpart YYYY:

i. The permittee must be in compliance with the emission limitations, operating limitations, and other requirements in 40 CFR 63, Subpart YYYY which apply to the permittee at all times. [40 CFR 63.6105(a)]

ii. At all times, the permittee 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 the permittee to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Division 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. [40 CFR 63.6105(c)]

f. Table 7 of 40 CFR 63, Subpart YYYY shows which parts of the General Provisions in §63.1 through 15 apply to the permittee. [40 CFR 63.6165]

Table 7 to 40 CFR 63, Subpart YYYY - Applicability of General Provisions to Subpart YYYY

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.1	General applicability of the General Provisions	Yes	Additional terms defined in §63.6175.
§63.2	Definitions	Yes	Additional terms defined in §63.6175.
§63.3	Units and abbreviations	Yes	
§63.4	Prohibited activities	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	
§63.6(b)(6)	[Reserved]		

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major	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	Yes	
§63.6(d)	[Reserved]		
§63.6(e)(1)(i)	General duty to minimize emissions	Yes before September 8, 2020.	
		No after September 8, 2020. See §63.6105 for general duty requirement.	
§63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	Yes before September 8, 2020.	
		No after September 8, 2020.	
§63.6(e)(1)(iii)	Operation and Maintenance Requirements	Yes	
§63.6(e)(2)	[Reserved]		
§63.6(e)(3)	SSMP	Yes before September 8, 2020.	
		No after September 8, 2020.	
§63.6(f)(1)	Applicability of standards except during startup, shutdown, or malfunction (SSM)	Yes before September 8, 2020. No after September 8, 2020.	
§63.6(f)(2)	Methods for determining compliance	Yes	
§63.6(f)(3)	Finding of compliance	Yes	
§63.6(g)(1)-(3)	Use of alternative standard	Yes	
§63.6(h)	Opacity and visible emission standards	No	Subpart YYYY 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 YYYY contains performance test dates at §63.6110.
§63.7(a)(3)	Section 114 authority	Yes	
§63.7(b)(1)	Notification of performance test	Yes	
§63.7(b)(2)	Notification of rescheduling	Yes	
§63.7(c)	Quality assurance/test plan	Yes	

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.7(d)	Testing facilities	Yes	
§63.7(e)(1)	Conditions for conducting performance tests	Yes before September 8, 2020.	
		No after September 8, 2020.	
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart YYYY specifies test methods at §63.6120.
§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 YYYY contains specific requirements for monitoring at §63.6125.
§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)	General duty to minimize emissions and CMS operation	Yes before September 8, 2020. No after September 8, 2020.	
§63.8(c)(1)(ii)	Parts for repair of CMS readily available	Yes	
§63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	Yes before September 8, 2020. No after September 8, 2020.	
§63.8(c)(2)-(3)	Monitoring system installation	Yes	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart YYYY does not require continuous opacity
			monitoring systems (COMS).
§63.8(c)(5)	COMS minimum procedures	No	
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart YYYY does not require COMS.
§63.8(d)(1)-(2)	CMS quality control	Yes	

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.8(d)(3)	Written procedures for CMS	Yes before September 8, 2020. No after September 8, 2020.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	
§63.8(f)(6)	Alternative to relative accuracy test	Yes	
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6135 and 63.6140.
§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.
§63.9(c)	Request for compliance extension	Yes	
§63.9(d)	Notification of special compliance requirements for new sources	Yes	
§63.9(e)	Notification of performance test	Yes	
§63.9(f)	Notification of visible emissions/opacity test	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	
§63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to relative accuracy test audit (RATA) is exceeded	Yes	
§63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
§63.9(i)	Adjustment of submittal deadlines	Yes	
§63.9(j)	Change in previous information	Yes	

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.9(k)	Electronic reporting procedures	Yes	Only as specified in §63.9(j).
§63.10(a)	Administrative provisions for recordkeeping and reporting	Yes	
§63.10(b)(1)	Record retention	Yes	
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	Yes before September 8, 2020. No after September 8, 2020.	
§63.10(b)(2)(ii)	Recordkeeping of failures to meet a standard	Yes before September 8, 2020. No after September 8, 2020. See §63.6155 for recordkeeping of (1) date, time and duration; (2) listing of affected source or equipment, and an estimate of the quantity of each regulated pollutant emitted over the standard; and (3) actions to minimize emissions and correct the failure.	
§63.10(b)(2)(iii)	Maintenance records	Yes	
§63.10(b)(2)(iv)-(v)	Records related to actions during SSM	Yes before September 8, 2020. No after September 8, 2020.	
§63.10(b)(2)(vi)-(xi)	CMS records	Yes	
§63.10(b)(2)(xii)	Record when under waiver	Yes	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes	
§63.10(b)(3)	Records of applicability determination	Yes	
§63.10(c)(1)-(14)	Additional records for sources using CMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(c)(15)	Use of SSM Plan	Yes before September 8, 2020. No after September 8, 2020.	
§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 YYYY does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No. After September 8, 2020, see 63.6150(a) for malfunction reporting requirements.	

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Citation	Subject	Applies to Subpart YYYY	Explanation
§63.10(e)(1) and (2)(i)	Additional CMS reports	Yes	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYY does not require COMS.
§63.10(e)(3)	Excess emissions and parameter exceedances reports	Yes	After September 8, 2020 submitted with the compliance report through CEDRI according to §63.6150(a).
§63.10(e)(4)	Reporting COMS data	No	Subpart YYYY does not require COMS.
§63.10(f)	Waiver for recordkeeping and reporting	Yes	
§63.11	Flares	No	
§63.12	State authority and delegations	Yes	
§63.13	Addresses	Yes	After September 8, 2020 not applicable to reports required to be submitted through CEDRI by 63.6150(c), (e), (f), or (g).
§63.14	Incorporation by reference	Yes	
§63.15	Availability of information	Yes	

BACT

g. The permittee shall prepare and maintain, within 90 days of startup, a good combustion and operation practices (GCOP) plan that defines, measures and verifies the use of operational and design practices determined as BACT for minimizing PM/PM_{10}/$PM_{2.5}$, CO, VOC, H_2SO_4, and GHG emissions. Any revisions requested by the Division shall be made and the revisions shall be maintained on site. The permittee shall operate according to the provisions of this plan at all times, including periods of startup, shutdown, and malfunction. The plan shall be incorporated into the plant standard operating procedures (SOP) and shall be made available for the Division's inspection. The plan shall include, but not be limited to: [401 KAR 51:017]

   i. A list of combustion optimization practices and a means of verifying the practices have occurred.

   ii. A list of combustion and operation practices to be used to lower energy consumption and a means of verifying the practices have occurred.

   iii. A list of the design choices determined to be BACT and verification that designs were implemented in the final construction.

h. The permittee shall install, operate, and maintain an SCR for the control of NO_X emissions from Unit 12. [401 KAR 51:017]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

i. The permittee shall install, operate, and maintain an oxidation catalyst for the control of VOC and CO emissions from Unit 12. [401 KAR 51:017]

SIP: Duct Burner Only Requirement:

j. During a startup period or a shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7 [40 KAR 59:015, Section 7 and Section 7(1)]

i. The permittee shall comply with 401 KAR 50:055, Section 2(5) [401 KAR 59:015, Section 7(1)(a)];

ii. The frequency and duration of startup periods or shutdown periods shall be minimized by the affected facility [401 KAR 59:015, Section 7(1)(b)];

iii. All reasonable steps shall be taken by the permittee to minimize the impacts of emissions on ambient air quality from the affected facility during startup periods and shutdown periods [401 KAR 59:015, Section 7(1)(c)];

iv. The actions, including duration of the startup period, shall be documented by signed, contemporaneous logs or other relevant evidence [401 KAR 59:015, Section 7(1)(d)]; and

v. Startups and shutdowns shall be conducted according to either [401 KAR 59:015, Section 7(1)(e)]:
1. The manufacturer's recommended procedures [401 KAR 59:015, Section 7(1)(e)1]; or
2. Recommended procedures for a unit of similar design, for which manufacturer's recommended procedures are available, as approved by the cabinet based on documentation provided by the permittee [401 KAR 59:015, Section 7(1)(e)2].

2. Emission Limitations:

NSPS KKKK

a. The permittee must meet the emission limits for NOx specified in 40 CFR 60, Subpart KKKK, Table 1. [40 CFR 60.4320(a)]

i. If the permittee operates Unit 12 at greater than or equal to 75 percent peak load, as a new turbine firing natural gas that has a heat input at peak load greater than 850 MMBtu/hr (HHV), the permittee shall meet an emission limit of 15 ppm NO_x at 15% O_2; or 54 ng/J of useful output (0.43 lb/MWh), based upon a 30-unit operating day rolling average (per 40 CFR 60.4350(h)). [40 CFR 60.4320 & 40 CFR 60, Subpart KKKK, Table 1].

ii. If the permittee operates Unit 12 at less than 75 percent peak load (HHV), as the output

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

is greater than 30 MW, the permittee shall meet an emission limit of 96 ppm at 15% O_2; or 590 ng/J of useful output (4.7 lb/MWh), based upon a 30-unit operating day rolling average (per 40 CFR 60.4350(h)) [40 CFR 60.4320 & 40 CFR 60, Subpart KKKK, Table 1].

Commented [MZ24]: KDAQ - We may consider removing this condition. You will see that we did not include the other related MRR requirements for the < 75% operational mode.

Compliance Demonstration:
Compliance shall be demonstrated according to **1. Operating Limitations** a., **3. Testing Requirements** a., b. & d., **4. Specific Monitoring Requirements** a. – c., and **6. Specific Reporting Requirements** a. – d.

b. As Unit 12 is located in a continental area, the permittee must comply with either 40 CFR 60.4330(a)(1) or (a)(2). [40 CFR 60.4330(a)]

i. The permittee shall not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/ MMBtu) heat input [40 CFR 60.4330(a)(2)].

Compliance Demonstration:
Compliance shall be demonstrated according to 1**. Operating Limitations** a., **3. Testing Requirements** c. & d., **4. Specific Monitoring Requirements** d. & e., and **6. Specific Reporting Requirements** c.

NESHAP YYYY

c. Unit 12, which is lean premix gas-fired stationary combustion turbines as defined in 40 CFR 63.6175, must limit the concentration of formaldehyde in the exhaust to 91 ppbvd or less at 15-percent O_2, except during turbine startup. [40 CFR 63.6100 and Table 1, Item 1, of 40 CFR 63, Subpart YYYY]

Compliance Demonstration:
Compliance shall be demonstrated according to 1**. Operating Limitations** b. – f., **3. Testing Requirements** e. – g., **4. Specific Monitoring Requirements** f. – h., **5. Specific Recordkeeping Requirements** a. – e., and **6. Specific Reporting Requirements** e. – n.

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BACT

d. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and CO_2 to exceed the limits in the following table. [401 KAR 51:017]

Fuel	Pollutant	Emission Limit	Averaging Period
Natural Gas	NO_X	2 ppm_{vd} at 15% O_2 with or without DB firing 151.4 tons per 12-month rolling	30-day† 12-month*
	CO	2 ppm_{vd} at 15% O_2 with or without DB firing 134.6 tons per 12-month rolling	30-day† 12-month*
	VOC	1 ppm_{vd} at 15% O_2 without DB firing 2 ppm_{vd} at 15% O_2 with DB firing 64.6 tons per 12-month rolling	3-hr† 3-hr† 12-month*
	$PM/PM_{10}/PM_{2.5}$	0.005 lb/MMBtu with or without DB firing	3-hr*
	H_2SO_4	0.5 gr S/100 scf	Annual
	CO_2	815 lb/MW-g with DB firing 925 lb/MW-g without DB Firing	12-month*

† For short-term NO_X, CO, VOC emission limits, during steady-state operation, exclude any data recorded during periods of startup and shutdown.
* For 12-month NO_X, CO, and VOC emission limits and $PM/PM_{10}/PM_{2.5}$ and CO_2 emission limits, include periods of startup and shutdown.

Compliance Demonstration:
Compliance shall be demonstrated according to **3. Operating Limitations** g. – i., **3. Testing Requirements** a., b., d., h., & i., **4. Specific Monitoring Requirements** i. – m., **5. Specific Recordkeeping Requirements** f. & g., and **6. Specific Reporting Requirements** TBD.

SIP: DB Firing Only

e. The permittee shall not cause emissions of particulate matter in excess of 0.10 lb/MMBtu [401 KAR 59:015, Section 4 (1) (b)].

f. The permittee shall not cause emissions of particulate matter in excess of twenty percent opacity, except [401 KAR 59:015, Section 4 (2)]:

i. A maximum of twenty-seven percent opacity shall be allowed for one six minute period in any sixty consecutive minutes [401 KAR 59:015, Section 4 (2) (a)];

ii. For emissions from an affected facility caused by building a new fire, emissions during the period required to bring the boiler up to operation conditions shall be allowed, is the method used is recommended by the manufacturer and the time does not exceed the manufacturer's recommendations [401 KAR 59:015, Section 4 (2) (c)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

g. The permittee shall not cause emissions of sulfur dioxide in excess of 0.8 lb/MMBtu [401 KAR 59:015, Section 5 (1) (b) 1.].

Compliance Demonstration:
DB firing in Unit 12 is assumed to be in compliance with the applicable 401 KAR 59:015 particulate matter, sulfur dioxide, and opacity standards while burning natural gas.

3. Testing Requirements:

NSPS KKKK and NO_X BACT

a. As the permittee elects to install and certify a NO_X-diluent CEMS under §§ 60.4335(b) and 60.4345, the initial performance test required under 40 CFR 60.8 may be performed in the following alternative manner [40 CFR 60.4405]:

i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs [40 CFR 60.4405(a)].

ii. For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit [40 CFR 60.4405(b)].

iii. Use the test data both to demonstrate compliance with the applicable NO_x emission limit under 40 CFR 60.4320 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR 60.4335 [40 CFR 60.4405(c)].

iv. Compliance with the applicable emission limit in 40 CFR 60.4320 is achieved if the arithmetic average of all of the NO_x emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit [40 CFR 60.4405(d)].

b. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. The permittee may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The permittee shall conduct three separate test runs for each performance test. The minimum time per run is 20 minutes [40 CFR 60.4400(b)].

i. For a combined cycle and CHP turbine systems with supplemental heat (duct burner), the permittee shall measure the total NO_x emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test [40 CFR 60.4400(b)(2)].

ii. Compliance with the applicable emission limit in 40 CFR 60.4320 shall be demonstrated at each tested load level. Compliance is achieved if the three-run

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arithmetic average NO_x emission rate at each tested level meets the applicable emission limit in 40 CFR 60.4320 [40 CFR 60.4400(b)(4)].

iii. If the permittee elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit [40 CFR 60.4400(b)(5)].

iv. The ambient temperature must be greater than 0 °F during the performance test [40 CFR 60.4400(b)(6)].

c. The permittee shall conduct an initial SO_2 performance test, as required in 40 CFR 60.8. If necessary, subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test) using one of the four methodologies listed in 40 CFR 60.4415(a)(1) through (4). [40 CFR 60.4415(a)]

d. Except as specified in 40 CFR 60.8(a)(1) through (a)(4), within 60 days after achieving the maximum production rate at which the combustion turbines will be operated, but not later than 180 days after initial startup of the turbines, the permittee shall conduct the performance tests and furnish the Administrator a written report of the results of such performance tests. [40 CFR 60.8(a)]

NESHAP YYYY

e. The permittee shall conduct the initial performance tests or other initial compliance demonstrations in Table 4 of 40 CFR 63 Subpart YYYY that apply within 180 calendar days after the compliance date that is specified for the stationary combustion turbine in 40 CFR 63.6095 and according to the provisions in 40 CFR 63.7(a)(2) [40 CFR 63.6110(a)].

f. Subsequent performance tests for formaldehyde shall be performed on an annual basis as specified in Table 3 of 40 CFR 63, Subpart YYYY [40 CFR 63.6115].

g. The permittee shall conduct each performance test in Table 3 of 40 CFR 63 Subpart YYYY that applies [40 CFR 63.6120(a)].

i. Each performance test shall be conducted according to the requirements in Table 3 of 40 CFR 63 Subpart YYYY. [40 CFR 63.6120(b)]

ii. Performance tests shall be conducted at high load, defined as 100 percent plus or minus 10 percent. After September 8, 2020, performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. The permittee may not conduct performance tests during periods of malfunction. The permittee shall record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

conditions represent normal operation. Upon request, the permittee shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests [40 CFR 63.6120(c)].

iii. The permittee shall conduct three separate test runs for each formaldehyde performance test, and each test run shall last at least 1 hour [40 CFR 63.6120(d)].

BACT

h. Within 60 days after achieving the maximum production rate but no later than 180 days after initial startup of Unit 12, and every 5 years thereafter, the permittee shall perform stack testing for VOC and PM/PM_{10}/$PM_{2.5}$ emissions from Unit 12 using the following methods: [401 KAR 51:017, 52:020, Section 10]

i. Method 18, 25, or 25A or alternate approved method at the outlet of the stack in accordance with an approved test protocol for VOC.

ii. 40 CFR 51, Appendix M, Method 201A/202, and 40 CFR 60, Appendix A, Method 5 (or an alternate method as approved by the Division) at the outlet of the stack in accordance with an approved test protocol for filterable and condensable PM.

i. The permittee shall establish a minimum or maximum operating parameter value, or an operating parameter range for each parameter to be monitored for each control device during testing. The permittee shall monitor and record the following parameters: [401 KAR 51:017, 52:020, Section 10]

i. The rate of ammonia injection into the SCR, optimized during testing to minimize ammonia slip and

ii. The inlet temperature for the oxidation catalyst.

4. Specific Monitoring Requirements:

NSPS KKKK and NO_X BACT

a. As an alternative to performing annual performance tests, the permittee may install, maintain, calibrate and operate one of the following continuous monitoring systems [40 CFR 60.4340(b)]:

i. Continuous emission monitoring as described in 40 CFR 60.4335(b) and 60.4345 [40 CFR 60.4340(b)(1)].

ii. Pursuant to 40 CFR 60.4335(b),

1. The permittee may install, certify, maintain, and operate a CEMS consisting of a NO_x monitor and a diluent gas (O_2 or CO_2) monitor, to determine the hourly NO_x emission rate in ppm or lb/MMBtu; and [40 CFR 60.4335(b)(1)]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. For units complying with the output-based standard, install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to the affected unit; and [40 CFR 60.4335(b)(2)]
3. For units complying with the output-based standard, install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of the unit in megawatt-hours; and [40 CFR 60.4335(b)(3)]
4. For combined heat and power units complying with the output-based standard, install, calibrate, maintain, and operate meters for useful recovered energy flow rate, temperature, and pressure, to continuously measure the total thermal energy output in British thermal units per hour (Btu/h) [40 CFR 60.4335(b)(4)].

b. Pursuant to 40 CFR 60.4340(b)(1), the NO_x CEMS shall meet the following requirements [40 CFR 60.4345]:

i. Each NO_x diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to 40 CFR 60, except the 7-day calibration drift is based on unit operating days, not calendar days. With Division approval, Procedure 1 in appendix F to 40 CFR 60 is not required. Alternatively, a NO_x diluent CEMS that is installed and certified according to appendix A of 40 CFR 75 is acceptable for use. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis [40 CFR 60.4345(a)].

ii. As specified in 40 CFR 60.13(e)(2), during each full unit operating hour, both the NO_x monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_x emission rate for the hour [40 CFR 60.4345(b)].

iii. Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with Division approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to 40 CFR 75 are acceptable for use [40 CFR 60.4345(c)].

iv. Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions [40 CFR 60.4345(d)].

v. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in 40 CFR 60.4345(a), (c), and (d). For the CEMS and fuel flow meters, the permittee may, with Division approval, satisfy the

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to 40 CFR 75 [40 CFR 60.4345(e)].

c. The permittee shall identify excess emissions using the following guidelines: [40 CFR 60.4350]:

i. All CEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h) [40 CFR 60.4350(a)].

ii. For each unit operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system shall calculate and record the hourly NO_x emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in appendix A of 40 CFR Part 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations [40 CFR 60.4350(b)].

iii. Correction of measured NO_x concentrations to 15 percent O_2 is not allowed [40 CFR 60.4350(c)].

iv. If the permittee has installed and certified a NO_x diluent CEMS to meet the requirements of 40 CFR Part 75, the Division may approve that only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c) [40 CFR 60.4350(d)].

v. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data shall be reduced to hourly averages [40 CFR 60.4350(e)].

vi. Calculate the hourly average NO_x emission rates, in units of the emission standards under 40 CFR 60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output-based standard [40 CFR 60.4350(f)]:

1. For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of 40 CFR 60, Subpart KKKK cited below, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations [40 CFR 60.4350(f)(2)]:

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

$$E = \frac{(NO_x)_h * (HI)_h}{P} \quad \text{(Eq. 1)}$$

Where:

E = hourly NO_x emission rate, in lb/MWh

$(NO_x)_h$ = hourly NO_x emission rate, in lb/MMBtu

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flowmeters, e.g., calculated using Equation D-15a in appendix D to 40 CFR 75, and

P = gross energy output of the combustion turbine in MW

$$P = (PE)_t + (PE)_c + P_S + P_O \quad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system (MW)

$(PE)_t$ = electrical or mechanical energy output of the CT (MW)

$(PE)_c$ = electrical or mechanical output of the steam turbine (MW)

$$P_S = \frac{Q * H}{3.413x10^6\ Btu/MWh}$$

Where:

P_S = useful thermal energy of the system, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/hr,

$3.413x10^6$ = conversion from Btu/hr to MW.

P_O = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

SO_2

d. The permittee must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used. [40 CFR 60.4360]

e. The permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. The permittee shall use the following source of information to make the required demonstration [40 CFR 60.4365]:

   i. The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas. [40 CFR 60.4365(a)].

NESHAP YYYY

f. The permittee shall monitor on a continuous basis the catalyst inlet temperature in order to comply with the operating limitations in Table 2 and as specified in Table 5 of 40 CFR YYYY [40 CFR 63.6125(a)].

   i. For a stationary combustion turbine that is required to comply with the emissions limitation for formaldehyde and is using an oxidation system, the permitting shall maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. The permittee is not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4- hour rolling average catalyst inlet temperature [40 CFR 63.6125(a) and Table 2, Item 1, of 40 CFR 63, Subpart YYYY].

   ii. Initial compliance is demonstrated if the average formaldehyde concentration meets the emission limitations specified in Table 1 of 40 CFR 63, Subpart YYYY [40 CFR 63.6110, 63.6125, 63.6130, and Table 4 40 CFR 63, Subpart YYYY].

   iii. Continuous compliance with the operating limit is demonstrated by continuously monitoring the inlet temperature to the catalyst and maintaining the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer [40 CFR 63.6135, 63.6140(a), and Table 5, Item 1 of 40 CFR 63, Subpart YYYY].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

g. Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), the permittee shall conduct all parametric monitoring at all times the stationary combustion turbine is operating [40 CFR 63.6135(a)].

h. The permittee shall not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. The permittee shall use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine [40 CFR 63.6135(b)].

BACT

i. The permittee shall measure CO and NO_X emissions using CEMS to demonstrate compliance with the applicable CO and NO_X emission limit under 401 KAR 51:017. The permittee shall install, certify, maintain, and operate a CEMS consisting of a CO monitor, NO_x monitor, and a diluent gas (O_2 or CO_2) monitor, to determine the hourly CO and NO_x emission rate in ppm, by volume, and oxygen in volume percent, on a dry basis. The 30-operating day rolling average is determined by calculating the arithmetic average of all hourly emission rate for the 30-operating days, except for data obtained during startup, shutdown, or malfunction. [401 KAR 51:017; 40 CFR 60, Appendix B, Performance Specification 2; 40 CFR 75, Appendix A; and 401 KAR 52:020, Section 10]

j. The permittee shall install, calibrate at least annually, maintain and operate a device to continuously monitor the rate of ammonia injection in the SCR to ensure that it does not fall outside of the range documented by the manufacturer's specifications or the range determined during the most recent performance test. Ammonia usage must be optimized to minimize ammonia slip. [401 KAR 51:017; 401 KAR 52:020, Section 10]

k. The permittee may use approved CEMS methodologies or other calculation methodologies of 40 CFR Part 75 Appendix G to demonstrate compliance with the applicable CO_2 emission limit under 401 KAR 51:017. The annual rolling average will be calculated at the end of each calendar month as the sum of monthly CO_2 mass (lbs) including non-operational periods divided by the sum of MWh-g for 12 consecutive months. [401 KAR 51:017; 40 CFR 60, Appendix B, Performance Specification 3; 40 CFR 75, Appendix A; 40 CFR 75, Appendix G; and 401 KAR 52:020, Section 10]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

l. As the BACT limit for CO_2 is on an output basis (e.g., lb CO_2 per gross MWh), the permittee must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output from the affected EGU. These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20-2010 (incorporated by reference, see § 60.17). Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour. [401 KAR 51:017; 401 KAR 52:020, Section 10].

m. The permittee shall monitor the following [401 KAR 52:020, Section 10]:

i. The monthly number of cold start, warm start, hot start, and shutdown events;

ii. The monthly number of hours in "fired" and "unfired" modes; and

iii. The monthly natural gas usage in "fired" and "unfired" modes in MMscf.

n. Refer to **Section F** for general monitoring requirements

5. Specific Recordkeeping Requirements:

NSPS Subpart KKKK

{Shown above in 60.4350(b)}

NESHAP YYYY

a. The permittee shall develop and implement a CMS quality control program that includes written procedures for CMS according to 40 CFR 63.8(d)(1) through (2). The permittee 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 40 CFR Part 63, to be made available for inspection, upon request, by the Administrator. If the performance evaluation plan is revised, the permittee 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. The program of corrective action should be included in the plan required under §63.8(d)(2) [40 CFR 63.6125(e)].

b. The permittee shall keep the records as described in 40 CFR 63.6155(a)(1) through (7) [40 CFR 63.6155(a)].

i. A copy of each notification and report submitted to comply with 40 CFR 63, Subpart YYYY, including all documentation supporting any Initial Notification or Notification of Compliance Status submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.6155(a)(1)]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

ii. Records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(i). [40 CFR 63.6155(a)(2)]

iii. Records of all maintenance on the air pollution control equipment as required in 40 CFR 63.10(b)(2)(ii). [40 CFR 63.6155(a)(5)]

iv. Records of the date, time, and duration of each startup period, recording the periods when the affected source was subject to the standard applicable to startup. [40 CFR 63.6155(a)(6)]

v. Keep records as follows: [40 CFR 63.6155(a)(7)]

1. Record the number of deviations. For each deviation, record the date, time, cause, and duration of the deviation. [40 CFR 63.6155(a)(7)(i)]
2. For each deviation, record and retain a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions. [40 CFR 63.6155(a)(7)(ii)]
3. Record actions taken to minimize emissions in accordance with 40 CFR 63.6105(c), and any corrective actions taken to return the affected unit to its normal or usual manner of operation. [40 CFR 63.6155(a)(7)(iii)]

c. The permittee shall keep the records required in Table 5 of 40 CFR 63 Subpart YYYY to show continuous compliance with each operating limitation that applies [40 CFR 63.6155(c)].

d. Any records required to be maintained by this part that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the Division or the EPA as part of an on-site compliance evaluation [40 CFR 63.6155(d)].

e. The permittee shall maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection according to 40 CFR 63.10(b)(1). As specified in 40 CFR 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, corrective action, report, or record. The permittee shall retain the records of the most recent 2 years on site or the records shall be accessible on site. The records of the remaining 3 years may be retained off site. [40 CFR 63.6160]

BACT

f. The permittee shall maintain records of NO_X and CO CEMS data to demonstrate compliance with the applicable limits under 401 KAR 51:017. [401 KAR 52:020, Section 10]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

g. The permittee shall maintain records of the following [401 KAR 52:020, Section 10]:

i. The monthly and 12-month rolling number of cold start, warm start, hot start, and shutdown events times the vendor supplied pounds of NO_X, CO, and VOC per event;

ii. The monthly and 12-month rolling number of hours in "fired" and "unfired" modes;

iii. The monthly and 12-month rolling natural gas usage in "fired" and "unfired" modes in MMscf;

iv. The hourly NO_X and CO CEMS data inclusive of all operational hours and startup and shutdown periods;

v. The monthly and 12-month rolling emissions of NO_X, CO, and VOC emissions from Unit 12 inclusive of all startup and shutdown events and steady-state operations to demonstrate compliance with the applicable limits under 401 KAR 51:017;

vi. The monthly and 12-month rolling average pounds of CO_2 emitted on a lb/MWh-g from the NGCC to demonstrate compliance with the applicable limits under 401 KAR 51:017, and

vii. The GCOP Plan as well as any revisions to demonstrate compliance with the applicable operational restrictions under 401 KAR 51:017 for PM/PM_{10}/$PM_{2.5}$, CO, VOC, H_2SO_4, and GHG emissions.

h. Refer to **Section F** for general recordkeeping requirements.

6. Specific Reporting Requirements:

NSPS Subpart KKKK

a. The permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions shall be reported for all periods of unit operation, including start-up, shutdown, and malfunction [40 CFR 60.4375(a)].

b. If the permittee is required to install a continuous monitoring device, the permittee shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form to the Division semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Division, 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 [40 CFR 60.4395 and 40 CFR 60.7(c)]:

i. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

of each time period of excess emissions. The process operating time during the reporting period [40 CFR 60.7(c)(1)].

ii. 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 [40 CFR 60.7(c)(2)].

iii. 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 [40 CFR 60.7(c)(3)].

iv. 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. [40 CFR 60.7(c)(4)]

c. All reports required under 40 CFR 60.7(c) shall be postmarked by the 30th day following the end of each reporting period [40 CFR 60.4395].

d. For turbines using continuous emission monitoring, periods of excess emissions and monitor downtime that must be reported are defined as follows [40 CFR 60.4380(b)]:

i. An excess emissions is any unit operating period in which the 30-day rolling average NO_x emission rate exceeds the applicable emission limit in 40 CFR 60.4320. For the purposes of 40 CFR 60, Subpart KKKK, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three-unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of 40 CFR 60, Subpart KKKK, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30- day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30-unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours [40 CFR 60.4380(b)(1)].

ii. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee will use this information for compliance purposes [40 CFR 60.4380(b)(2)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

NESHAP Subpart YYYY

e. Notification of initial compliance and continuous compliance:

i. To demonstrate initial compliance with the emission and operating limitations, the permittee must submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in §63.6145(f). [40 CFR 63.6130(b)]

ii. To demonstrate continuous compliance with the emission and operating limitations, the permittee must report each instance in which they did not meet each emission limitation or operating limitation. The permittee must also report each instance in which they did not meet the requirements in Table 7 of this subpart that applies. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6150. [40 CFR 63.6140(b)]

f. The permittee shall submit all of the notifications in 40 CFR 63.7(b) Notification of Performance Testing and 40 CFR 63.7(c) Quality Assurance/Test Plan, 40 CFR 63.8(e) CMS Performance Evaluation (Except for 40 CFR 63.8(e)(5)(ii), which applies to COMS), 40 CFR 63.8(f)(4) Alternative Monitoring, and 40 CFR 63.9(b) Initial Notifications and 40 CFR 63.9(h) Notice of Compliance Status that apply by the dates specified [40 CFR 60, Subpart A, 40 CFR 63.6145(a) and Table 7 of 40 CFR 63, Subpart YYYY].

g. The permittee shall submit an Initial Notification not later than 120 calendar days after becoming subject to 40 CFR 63, Subpart YYYY. [40 CFR 63.6145(c)]

h. If the permittee is required to conduct an initial performance test, submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in 40 CFR 63.7(b)(1). [40 CFR 63.6145(e)]

i. The permittee shall submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, the permittee shall submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test [40 CFR 63.6145(f)].

j. **Compliance report**. The permittee shall submit a semiannual compliance report according to Table 6 of 40 CFR 63, Subpart YYYY. The semiannual compliance report must contain the information described in 40 CFR 63.6150(a)(1) through (5). The semiannual compliance report, including the excess emissions and monitoring system performance reports of 40 CFR 63.10(e)(3), shall be submitted by the dates specified in 40 CFR 63.6150(b)(1) through (5), unless the Administrator has approved a different schedule. After September 8, 2020, or once the reporting template has been available on the

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, whichever date is later, the permittee shall submit all subsequent reports to the EPA following the procedure specified in 40 CFR 63.6150(g) [40 CFR 63.6150(a)].

i. Company name and address. [40 CFR 63.6150(a)(1)]

ii. Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report. [40 CFR 63.6150(a)(2)]

iii. Date of report and beginning and ending dates of the reporting period. [40 CFR 63.6150(a)(3)]

iv. Report each deviation in the semiannual compliance report. Report the information specified in 40 CFR 63.6150(a)(5)(i) through (iv) [40 CFR 63.6150(a)(5)].

1. Report the number of deviations. For each instance, report the start date, start time, duration, and cause of each deviation, and the corrective action taken. [40 CFR 63.6150(a)(5)(i)]
2. For each deviation, the report shall include a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions. [40 CFR 63.6150(a)(5)(ii)]
3. Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks), as applicable, and the corrective action taken. [40 CFR 63.6150(a)(5)(iii)]
4. Report the total operating time of the affected source during the reporting period. [40 CFR 63.6150(a)(5)(iv)]

k. Dates of submittal for the semiannual compliance report are provided in 40 CFR 63.6150(b)(1) through (5). [40 CFR 63.6150(b)]

i. The first semiannual compliance report shall cover the period beginning on the compliance date specified in 40 CFR 63.6095 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 specified in 40 CFR 63.6095 [40 CFR 63.6150(b)(1)].

ii. The first semiannual compliance report shall 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 in 40 CFR 63.6095 [40 CFR 63.6150(b)(2)].

iii. Each subsequent semiannual compliance report shall cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31 [40 CFR 63.6150(b)(3)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

iv. Each subsequent semiannual compliance report shall 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 [40 CFR 63.6150(b)(4)].

v. For each stationary combustion turbine that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established the date for submitting annual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established instead of according to the dates in 40 CFR 63.6150(b)(1) through (4) [40 CFR 63.6150(b)(5)].

l. **Performance test report.** Within 60 days after the date of completing each performance test required by 40 CFR 63, Subpart YYYY, the permittee shall submit the results of the performance test (as specified in 40 CFR 63.6145(f)) following the procedures specified in 40 CFR 63.6150(f)(1) through (3) [40 CFR 63.6150(f)].

i. ***Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reportingair-emissions/electronic-reporting-tool-ert) at the time of the test***. Submit the results of the performance test to the EPA via the CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (***https://cdx.epa.gov***). The data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, the permittee may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website [40 CFR 63.6150(f)(1)].

ii. ***Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.*** The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI [40 CFR 63.6150(f)(2)].

iii. ***Confidential business information (CBI).*** If the permittee claims some of the information submitted under 40 CFR 63.6150(f)(1) is CBI, the permittee must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. 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 in 40 CFR 63.6150(f)(1) [40 CFR 63.6150(f)(3)].

m. If the permittee is required to submit reports following the procedure specified in this

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

paragraph, the permittee must submit reports to the EPA via CEDRI, which can be accessed through the EPA's CDX (https://cdx.epa.gov/). The permittee must use the appropriate electronic report template on the CEDRI website (https://www.epa.gov/electronic-reporting-air- emissions/compliance-and-emissions-data-reporting-interface- cedri) for this subpart. The date report templates become available will be listed on the CEDRI website. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. If the permittee claims some of the information required to be submitted via CEDRI is CBI, submit a complete report, including information claimed to be CBI, to the EPA. The report must be generated using the appropriate form on the CEDRI website. 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. [40 CFR 63.6150(g)]

n. If the permittee is required to electronically submit a report through CEDRI in the EPA's CDX, the permittee may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, the permittee must meet the requirements outlined in the following paragraphs. [40 CFR 63.6150(h)]

   i. The permittee must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems. [40 CFR 63.6150(h)(1)].

   ii. The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due. [40 CFR 63.6150(h)(2)]

   iii. The outage may be planned or unplanned. [40 CFR 63.6150(h)(3)]

   iv. The permittee must submit notification to the Administrator in writing as soon as possible following the date the permittee first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting. [40 CFR 63.6150(h)(4)]

   v. The permittee must provide to the Administrator a written description identifying: [40 CFR 63.6150(h)(5)]

      1. The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable; [40 CFR 63.6150(h)(5)(i)]
      2. A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage; [40 CFR 63.6150(h)(5)(ii)]
      3. Measures taken or to be taken to minimize the delay in reporting; and [40 CFR 63.6150(h)(5)(iii)]

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4. The date by which the permittee proposes to report, or if the permittee has already met the reporting requirement at the time of the notification, the date reported. [40 CFR 63.6150(h)(5)(iv)]

vi. If the permittee is required to electronically submit a report through CEDRI in the EPA's CDX, the permittee may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, the permittee must meet the requirements outlined in 40 CFR 63.6150 (i)(1) through (5). [40 CFR 63.6150(i)]

1. The permittee 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 the permittee from complying with the requirement to submit a 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). [40 CFR 63.6150(i)(1)]
2. The permittee must submit notification to the Administrator in writing as soon as possible following the date the permittee first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting. [40 CFR 63.6150(i)(2)]
3. The permittee must provide to the Administrator: [40 CFR 63.6150(i)(3)]
   A. A written description of the force majeure event; [40 CFR 63.6150(i)(3)(i)]
   B. A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; [40 CFR 63.6150(i)(3)(ii)
   C. Measures taken or to be taken to minimize the delay in reporting; and [40 CFR 63.6150(i)(3)(iii)]
   D. The date by which the permittee propose to report, or if the permittee has already met the reporting requirement at the time of the notification, the date the permittee reported. [40 CFR 63.6150(i)(3)(iv)]
4. The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator. [40 CFR 63.6150(i)(4)]
5. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. [40 CFR 63.6150(i)(5)]

7. Specific Control Equipment Operating Conditions:

a. See Section E – Source Control Equipment Requirements for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 59 & 60 Natural Gas Combustion Units Supporting NGCC System

Commented [MZ25]: KDAQ - Add new EUs.

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel
59	Auxiliary Boiler	June 2026	95.52 MMBtu/hr	Natural Gas
60	Fuel Gas (Dewpoint) Heater	June 2026	15.65 MMBtu/hr	

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*
401 KAR 59:015, *New indirect heat exchangers*
401 KAR 60:005, Section (2)(2)(d), 40 C.F.R. 60.40c to 60.48c (**Subpart Dc**), *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*
401 KAR 63:002, Section (2)(4)(iiii), 40 C.F.R. 63.7480 to 63.7575, Tables 1 to 13 (**Subpart DDDDD**), *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*

1. **Operating Limitations:**
   a. For EUs 59 and 60, the permittee shall complete an annual or 5-year tune-up as applicable as specified in 40 CFR 63.7540 [40 CFR 63.7500(a)(1) referencing Items 1 and 3 of 40 CFR 63, Subpart DDDDD, Table 3].

   b. At all times, the permittee shall 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. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that 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 [40 CFR 63.7500(a)(3)].

   c. Because EUs 59 and 60 are units designed to burn gas 1 fuels, they are not subject to the emission limits in 40 CFR 63, Subpart DDDDD Tables 1 and 2 or 11 through 15, or the operating limits in 40 CFR 63, Subpart DDDDD Table 4. [40 CFR 63.7500(e)]

   d. The permittee shall demonstrate initial compliance with the applicable work practice standards in 40 CFR 63, Subpart DDDDD, Table 3 within the applicable annual schedule as specified in 40 CFR 63.7515(d) following the initial compliance date specified in 40 CFR 63.7495(a). Thereafter, the permittee is required to complete the annual tune-up as specified in 40 CFR 63.7515(d) [40 CFR 63.7510(g), 63.7540(a)(10), and 63.7540(a)(11)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

e. The permittee shall conduct an annual performance tune-up according to 40 CFR 63.7540(a)(10). Each annual tune-up specified in 40 CFR 63.7540(a)(10) shall be no more than 13 months after the previous tune-up. If the unit is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup [40 CFR 63.7515(d), 63.7540(a)(10), and 63.7540(a)(13)].

f. The permittee shall conduct an annual tune-up of the boiler or process heater as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. This frequency does not apply to units with continuous oxygen trim systems that maintain an optimum air to fuel ratio [CFR 63.7540(a)(10), 40 CFR 63.7540(a)(11)].

i. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may perform the burner inspection any time prior to the tuneup or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment [40 CFR 63.7540(a)(10)(i)];

ii. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available [40 CFR 63.7540(a)(10)(ii)];

iii. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection [40 CFR 63.7540(a)(10)(iii)].

iv. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject [40 CFR 63.7540(a)(10)(iv)].

v. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and [40 CFR 63.7540(a)(10)(v)]

vi. Maintain on-site and submit, if requested by the Division, a report containing the information in 40 CFR 63.7540(a)(10)(vi)(A) through (C) [40 CFR 63.7540(a)(10)(vi)],

1. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

and after the tune-up of the boiler or process heater [40 CFR 63.7540(a)(10)(vi)(A)];

2. A description of any corrective actions taken as part of the tune-up; and [40 CFR 63.7540(a)(10)(vi)(B)]

3. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may establish the fuel used by each unit [40 CFR 63.7540(a)(10)(vi)(C)].

g. If the boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, the owner or operator must conduct a tune-up of the boiler or process heater every 5 years as specified in 40 CFR 63.7540(a)(10)(i) through (vi) to demonstrate continuous compliance. The owner or operator may delay the burner inspection specified in 40 CFR 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown, but the owner or operator must inspect each burner at least once every 72 months. If an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, the owner or operator shall set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up. [40 CFR 63.7540(a)(12)]

h. During a startup period or shutdown period, the permittee shall comply with the work practice standards established in 401 KAR 59:015, Section 7. An affected facility subject to 40 CFR 63.7500 shall meet the work practice standards established in 40 CFR Part 63, Table 3 to Subpart DDDDD, as established in 401 KAR 63:002, Section 2(4)(iiii) [401 KAR 59:015, Section 7 and 401 KAR 59:015, Section 7(2)(a)].

i. The permittee shall limit emissions through the use of LNBs and good combustion and operating practices. [401 KAR 51:017]

j. The permittee shall utilize natural gas with a maximum sulfur content of 0.5 gr/100 scf to control emissions of H_2SO_4. [401 KAR 51:017]

Compliance Demonstration:
Compliance shall be demonstrated according to **Section D.4.**

k. The permittee shall limit the hours of operation of EU 59 to no more than 4,000 hours per calendar year. [401 KAR 52:020, Section 10]
Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Recordkeeping Requirements** a.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

2. Emission Limitations:

a. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Emission Unit	Pollutant	Emission Limit	Averaging Period
EU 59	NO_X	0.036 lb/MMBtu	3-hr
EU 59	CO	0.037 lb/MMBtu	3-hr
EU 59	VOC	0.0054 lb/MMBtu	3-hr
EU 59	PM/PM_{10}/$PM_{2.5}$	0.007 lb/MMBtu (FPM+CPM PM, PM_{10}, and $PM_{2.5}$)	3-hr
EU 59	H_2SO_4	0.5 gr S/100 scf	Fuel Selection
EU 59	CO_2e	117.1 lb/MMBtu	Fuel Selection
EU 60	NO_X	0.038 lb/MMBtu	3-hr
EU 60	CO	0.038 lb/MMBtu	3-hr
EU 60	VOC	0.008 lb/MMBtu	3-hr
EU 60	PM/PM_{10}/$PM_{2.5}$	0.007 lb/MMBtu	3-hr
EU 60	H_2SO_4	0.5 gr S/100 scf	Fuel Selection
EU 60	CO_2e	117.1 lb/MMBtu	Fuel Selection

Compliance Demonstration:

b. If requested by the Division, compliance with the NO_X, CO, VOC, and/or PM/PM_{10}/$PM_{2.5}$ emissions limitations for Emission Unit 59 shall be demonstrated by an initial performance test as specified in **3. Testing Requirements** (a. through d.).

c. Compliance with the H_2SO_4, PM/PM_{10}/$PM_{2.5}$, and CO_2e emission limits for EU 59 and 60 shall be demonstrated via **1. Operating Limitations** (j.).

d. Compliance with the NO_X, CO, VOC, H_2SO_4, PM/PM_{10}/$PM_{2.5}$, and CO_2e emissions limitations for EUs 59 and 60 shall be demonstrated by the work practice standards found in **1. Operating Limitations** (a. through i.).

e. The permittee shall not cause emissions of particulate matter in excess of 0.10 lb/MMBtu [401 KAR 59:015, Section 4(1)(b)].

f. The permittee shall not cause emissions of particulate matter in excess of twenty percent opacity, except [401 KAR 59:015, Section 4(2)]:

i. A maximum of twenty-seven percent opacity shall be allowed for one six minute period in any sixty consecutive minutes [401 KAR 59:015, Section 4(2)(a)];

ii. For emissions from an affected facility caused by building a new fire, emissions during

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

the period required to bring the boiler up to operation conditions shall be allowed, is the method used is recommended by the manufacturer and the time does not exceed the manufacturer's recommendations [401 KAR 59:015, Section 4(2)(c)].

g. The permittee shall not cause emissions of sulfur dioxide in excess of 0.8 lb/MMBtu [401 KAR 59:015, Section 5(1)(b)1.].

Compliance Demonstration:
These units are assumed to be in compliance with the applicable 401 KAR 59:015 particulate matter, sulfur dioxide, and opacity standards while burning natural gas.

h. The owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month. [40 CFR 60.48c(g)(2)]

3. Testing Requirements:

a. If requested by the Division, the permittee shall conduct an initial performance test to demonstrate compliance with the applicable NOx emission limit under 401 KAR 51:017 using EPA Method 7 or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017 and 401 KAR 52:020, Section 10]

b. If requested by the Division, the permittee shall conduct an initial performance test to demonstrate compliance with the applicable CO emission limit under 401 KAR 51:017 using EPA Method 10 or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017 and 401 KAR 52:020, Section 10]

c. If requested by the Division, the permittee shall conduct an initial performance test to demonstrate compliance with the applicable VOC emission limit under 401 KAR 51:017 using EPA Methods 18, 25, or 25A or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017 and 401 KAR 52:020, Section 10]

d. If requested by the Division, the permittee shall conduct an initial performance test to demonstrate compliance with the applicable $PM/PM_{10}/PM_{2.5}$ emission limit under 401 KAR 51:017 using EPA Methods 5, 202, or alternate approved method in accordance with an approved test protocol. [401 KAR 51:017 and 401 KAR 52:020, Section 10]

4. Specific Monitoring Requirements:

a. The permittee shall monitor hours of operation and natural gas usage (MMscf or MMBtu) for EUs 59 and 60, on a monthly basis [401 KAR 52:020, Section 10; 40 CFR 60.48c(g)(2)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

5. Specific Recordkeeping Requirements:

b. The permittee shall maintain records of hours of operation and natural gas usage (MMscf or MMBtu) for EUs 59 and 60 on a monthly basis. [401 KAR 52:020, Section 10; 40 CFR 60.48c(g)(2)]

c. All records required under 40 CFR 60.48c shall be maintained by the permittee for a period of two years following the date of such record [40 CFR 60.48c(i)].

d. The permittee shall keep a copy of each notification and report submitted to comply with 40 CFR 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements of 40 CFR 63.10(b)(2)(xiv) [40 CFR 63.7555(a) and 63.7555(a)(1)].

e. If the permittee operates a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and uses an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, the permittee must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies [40 CFR 63.7555(h)].

f. Records of notifications and reports submitted to comply with 40 CFR 63 Subpart DDDDD and records of other compliance demonstrations and performance evaluations required in 40 CFR 63.10(b)(2)(viii) shall be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1) [40 CFR 63.7560(a)].

i. As specified in 40 CFR 63.10(b)(1), the permittee shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record [40 CFR 63.7560(b)].

ii. The permittee shall keep each record on site, or they shall be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years [40 CFR 63.7560(c)].

6. Specific Reporting Requirements:

a. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in 40 CFR 63, Subpart A. Some of the notifications must be submitted before the permittee is required to comply with the emission limits and work practice standards in 40 CFR 63, Subpart DDDDD [40 CFR 63.7495(d)].

b. The permittee must submit the Notification of Compliance Status containing the results of

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

the initial compliance demonstration according to the requirements in 40 CFR 7545(e) [40 CFR 63.7530(f)].

c. The permittee shall report each instance in which an emission limit and operating limit in 40 CFR 63, Subpart DDDDD, Table 3, as applicable, was not met. These instances are deviations from the emission limits or operating limits, respectively, in 40 CFR 63, Subpart DDDDD. These deviations shall be reported according to the requirements in 40 CFR 63.7550 [40 CFR 63.7540(b)].

d. The permittee shall submit to the Division all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified [40 CFR 63.7545(a)].

e. As specified in 40 CFR 63.9(b)(4) and (5), for startup of a new or reconstructed affected source on or after January 31, 2013, the permittee shall submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. For a new or reconstructed affected source that has reclassified to major source status, the permittee must submit an Initial Notification not later 120 days after the source becomes subject to 40 CFR 63, Subpart DDDDD. [40 CFR 63.7545(c)]

f. The permittee shall submit the Notification of Compliance Status and shall contain the information specified in 40 CFR 63.7545(e)(1) and (8) and shall be submitted within 60 days of the compliance date specified at 40 CFR 63.7495(b) [40 CFR 63.7545(e)].

   i. A description of the affected units including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with 40 CFR 63, Subpart DDDDD, description of the fuel burned, including whether the fuel was a secondary material determined by the permittee or the EPA through a petition process to be a non-waste under 40 CFR 241.3, whether the fuel was a secondary material processed from discarded non-hazardous secondary material within the meaning of 40 CFR 241.3, and justification for the selection of fuel burned during the compliance demonstration [40 CFR 63.7545(e)(1)].

   ii. In addition to information required in 40 CFR 63.9(h)(2), the notification of compliance status must include the following certifications of compliance, as applicable, and signed by a responsible official [40 CFR 63.7545(e)(8)]:

      1. "This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in 40 CFR 63.7540(a)(10)(i) through (vi)." [40 CFR 63.7545(e)(8)(i)].

g. If the permittee operates a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and intends to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of 40 CFR 63, 60, 61, or 65, or other gas 1 fuel

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to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575, the permittee must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in 40 CFR 63.7575. The notification must include the information specified in 40 CFR 63.7545(f)(1) through (5). [40 CFR 63.7545(f)]

i. Company name and address. [40 CFR 63.7545(f)(1)]

ii. Identification of the affected unit. [40 CFR 63.7545(f)(2)]

iii. Reason the permittee is unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began. [40 CFR 63.7545(f)(3)]

iv. Type of alternative fuel that the permittee intends to use. [40 CFR 63.7545(f)(4)]

v. Dates when the alternative fuel use is expected to begin and end. [40 CFR 63.7545(f)(5)]

h. If the permittee switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, the owner or operator shall provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify the information shown in 40 CFR 63.7545(h)(1) through (3). [40 CFR 63.7545(h)]

i. The permittee shall submit each report in 40 CFR 63, Subpart DDDDD, Table 9 that applies [40 CFR 63.7550(a)].

j. The permittee may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in 40 CFR 63.7550(b)(1) through (4) [40 CFR 63.7550(b)]:

i. If submitting an annual, biennial, or 5-year compliance report, the first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in 40 CFR 63.7495 and ending on December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for the source in 40 CFR 63.7495 [40 CFR 63.7550(b)(1)].

ii. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31 [40 CFR 63.7550(b)(2)].

iii. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31 [40 CFR 63.7550(b)(3)].

iv. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31 [40 CFR 63.7550(b)(4)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

v. For each affected source that is subject to permitting regulations pursuant to 40 CFR 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 71.6(a)(3)(iii)(A), the permittee may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in 40 CFR 63.7550(b)(1) through (4) [40 CFR 63.7550(b)(5)].

k. The permittee shall submit a compliance report with the information in 40 CFR 63.7550 (c)(5)(i) through (iii), (xiv), and (xvii) [40 CFR 63.7550(c)(1)]:

i. Company and Facility name and address [40 CFR 63.7550(c)(5)(i)].

ii. Process unit information, emission limitations, and operating parameter limitations [40 CFR 63.7550(c)(5)(ii)].

iii. Date of report and beginning and ending dates of the reporting period [40 CFR 63.7550(c)(5)(iii)].

iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annual, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown [40 CFR 63.7550(c)(5)(xiv)].

v. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report [40 CFR 63.7550(c)(5)(xvii)].

l. The permittee shall submit the reports according to the procedures specified in 40 CFR 63.7550(h)(1) through (3) [40 CFR 63.7550(h)].

i. The permittee must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI [40 CFR 63.7550(h)(3)].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

m. See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 61 **Emergency Diesel Generator**

Commented [MZ26]: KDAQ - Add new EU.

Description:	Kohler/KD2000 or similar
Primary Fuel:	Diesel
Maximum Continuous Rating:	2.18 MW (2,923 bhp)
Manufacture Date:	TBD
Construction Commenced:	June 2026

APPLICABLE REGULATIONS:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 to 60.4219, Tables 1 to 8 (**Subpart IIII**), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 to 63.6675, Tables 1a to 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**
   a. EU 61 does not have to meet the requirements of Subpart ZZZZ and of Subpart A of 40 CFR Part 63 except for the initial notification requirements of 40 CFR 63.6645(f). [40 CFR 63.6590(b)(1)]

   b. The permittee shall operate and maintain stationary CI ICE that achieves the emission standards as required in 40 CFR 60.4204 and 60.4205 over the entire life of the engine. [40 CFR 60.4206]

   c. Owners and operators of a stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that uses diesel fuel shall 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: [40 CFR 60.4207(b), 401 KAR 51:017]

      i. Overview. Except as specified in § 1090.300(a), diesel fuel must meet the ULSD per-gallon standards of this section. [40 CFR 1090.305(a)]

      ii. Sulfur standard: Maximum sulfur content of 15 ppm [40 CFR 1090.305(b)]

      iii. Cetane index or aromatic content. Diesel fuel must meet one of the following standards: [40 CFR 1090.305(c)]

         1. Minimum cetane index of 40. [40 CFR 1090.305(c)(1)].
         2. Maximum aromatic content of 35 volume percent. [40 CFR 1090.305(c)(2)]

   d. The permittee shall operate and maintain stationary CI ICE according to manufacturer's

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

instructions, change only those emission-related settings that are permitted by the manufacturer; and meet the requirements of 40 CFR part 1068, as they apply. [40 CFR 60.4211(a)(1) through (3)]

e. The permittee shall purchase an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable, for the same model year and maximum engine power. In addition, the permittee must install and configure the engine according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). [40 CFR 60.4211(c)]

f. If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance with 40 CFR 60.4211(g)(3). [40 CFR 60.4211(g)]

g. The permittee shall operate the emergency stationary ICE according to the requirements in 40 CFR 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing and operation in non-emergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the permittee does not operate the engine according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and shall meet all requirements for non-emergency engines. [40 CFR 60.4211(f)]

   i. There is no time limit on the use of emergency stationary ICE in emergency situations. [40 CFR 60.4211(f)(1)]

   ii. The permittee may operate the emergency stationary ICE for any combination of the purposes specified in 40 CFR 60.4211(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 60.4211(f)(2). [40 CFR 60.4211(f)(2)]

      1. 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. [40 CFR 60.4211(f)(2)(i)]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

iii. 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 and emergency demand response provided in 40 CFR 60.4211(f)(2). [40 CFR 60.4211(f)(3)]

h. If the permittee operates an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, the permittee shall install a non-resettable hour meter prior to startup of the emergency engine. [40 CFR 60.4209(a)]

2. Emission Limitations:

a. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Pollutant	Emission Limit
NMHC + NO_X	4.8 g/hp-hr
CO	2.6 g/hp-hr
PM/PM_{10}/$PM_{2.5}$	0.15 g/hp-hr
CO_2e	164 lb/MMBtu

Compliance with the NO_X, CO, VOC, PM/PM_{10}/$PM_{2.5}$, and CO_2e emissions limitations for EU 61 shall be demonstrated by the work practice standards found in **1. Operating Limitations** (b. through h.).

b. The permittee shall certify their stationary CI ICE to the certification 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. [40 CFR 60.4205(b) and 60.4202(a)(2)]

Pollutant	Emission Limit
NMHC + NO_X	4.8 g/hp-hr
CO	2.6 g/hp-hr
PM	0.15 g/hp-hr
Smoke emission standard (40 CFR 1039.105)	20% during the acceleration mode; 15% during the lugging mode; 50% during the peaks in either the acceleration or lugging modes.

Compliance Demonstration:
Compliance with the NMHC, NO_X, CO, and PM emissions limitations for EU 61 shall be demonstrated by the work practice standards found in **1. Operating Limitations** (b. through h.).

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. **Testing Requirements:**
   a. Testing shall be conducted at such times as may be requested by the cabinet in accordance with 401 KAR 50:045, Section 4.

4. **Specific Monitoring Requirements:**
   a. The permittee shall monitor the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

   b. The permittee shall monitor the hours of operation of the emergency generator. [401 KAR 52:020, Section 10 and 40 CFR 60.4209(a)]

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

   b. The permittee shall maintain records of the hours of operation on a monthly basis. [401 KAR 52:020, Section 10]

   c. The permittee shall meet the following recordkeeping requirements. [40 CFR 60.4214]

      i. Keep records of the hours of operation of the engine in emergency and non-emergency operation if the engine is not certified to meet the non-emergency emissions standards. [40 CFR 60.4214(b)]

      ii. If the emergency generator engine is equipped with a diesel particulate filter, keep records of any corrective action taken after the backpressure monitor has notified the permittee that the high backpressure limit of the engine is approached. [40 CFR 60.4214(c)]

6. **Specific Reporting Requirements:**
   a. The owner or operator is not required to submit an initial notification if the emergency engine is a certified engine. [40 CFR 60.4214(a)]

   b. If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the permittee is not required to submit an initial notification. Starting with the model years in Table 5 to NSPS Subpart IIII, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the permittee 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 permittee must record the time of operation of the engine and the reason the engine was in operation during that time. [40 CFR 60.4214(b)]

   c. Submit initial notification in accordance with 40 CFR 63.9(b)(2)(i) through (v) and a statement that stationary RICE has no additional requirements and explain the basis of the exclusion. By 40 CFR 63.6645(c), the initial notification should be submitted no later

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

than 120 days after startup(since 40 CFR 63.6595(a)(3) states startup is when compliance begins). [40 CFR 63.6645(f)]

d. See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 62 **Diesel Fired Pump Engine**

Commented [MZ27]: KDAQ - Add new EU.

Description:	Clarke JW6H-UFAD80 or Similar
Primary Fuel:	Diesel
Maximum Continuous Rating:	422 bhp
Manufacture Date:	TBD
Construction Commenced:	June 2026

APPLICABLE REGULATIONS:

401 KAR 51:017, *Prevention of significant deterioration of air quality*

401 KAR 60:005, Section 2(2)(dddd), 40 C.F.R. 60.4200 to 60.4219, Tables 1 to 8 (**Subpart IIII**), *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

401 KAR 63:002, Section 2(4)(eeee), 40 C.F.R. 63.6580 to 63.6675, Tables 1a to 8, and Appendix A (**Subpart ZZZZ**), *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

1. **Operating Limitations:**

a. The permittee shall meet the requirements of 40 CFR Part 63 by meeting the requirements of 40 CFR 60, Subpart IIII. No further requirements apply for the engine under 40 CFR Part 63. [40 CFR 63.6590(c)(6)]

b. Owners and operators of a stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that uses diesel fuel shall 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: [40 CFR 60.4207(b), 401 KAR 51:017]

i. Overview. Except as specified in § 1090.300(a), diesel fuel must meet the ULSD per-gallon standards of this section. [40 CFR 1090.305(a)]

ii. Sulfur standard: Maximum sulfur content of 15 ppm [40 CFR 1090.305(b)]

iii. Cetane index or aromatic content. Diesel fuel must meet one of the following standards: [40 CFR 1090.305(c)]

3. Minimum cetane index of 40. [40 CFR 1090.305(c)(1)].
4. Maximum aromatic content of 35 volume percent. [40 CFR 1090.305(c)(2)]

b. The permittee shall operate and maintain stationary CI ICE according to manufacturer's instructions change only those emission-related settings that are permitted by the manufacturer; and meet the requirements of 40 CFR part 1068, as they apply. [40 CFR 60.4211(a)(1)-(3)]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

c. The permittee shall purchase an engine certified to the emission standards in 40 CFR 60.4205(c), as applicable, for the same model year and maximum engine power. In addition, the permittee must install and configure the engine according to the manufacturer's emission-related specifications, except as permitted in 40 CFR 60.4211(g). [40 CFR 60.4211(c)]

d. If the permittee does not install, configure, operate, and maintain the engine and control device according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance with 40 CFR 60.4211(g)(3). [40 CFR 60.4211(g)]

e. The permittee shall operate the emergency stationary ICE according to the requirements in 40 CFR 60.4211(f)(1) through (3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60, Subpart IIII, any operation other than emergency operation, maintenance and testing and operation in non- emergency situations for 50 hours per year, as described in 40 CFR 60.4211(f)(1) through (3), is prohibited. If the permittee does not operate the engine according to the requirements in 40 CFR 60.4211(f)(1) through (3), the engine will not be considered an emergency engine under 40 CFR 60, Subpart IIII and shall meet all requirements for non-emergency engines. [40 CFR 60.4211(f)]

i. There is no time limit on the use of emergency stationary ICE in emergency situations. [40 CFR 60.4211(f)(1)]

ii. The permittee may operate the emergency stationary ICE for any combination of the purposes specified in 40 CFR 60.4211(f)(2)(i) through (iii) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by 40 CFR 60.4211(f)(3) counts as part of the 100 hours per calendar year allowed by 40 CFR 60.4211(f)(2). [40 CFR 60.4211(f)(2)]

1) 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 permittee 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 permittee maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. [40 CFR 60.4211(f)(2)(i)]

iii. 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

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

and emergency demand response provided in 40 CFR 60.4211(f)(2). [40 CFR 60.4211(f)(3)]

2. Emission Limitations:

a. The permittee shall not allow the emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e to exceed the limits in the following table: [401 KAR 51:017]

Pollutant	Emission Limit
NMHC + NO_X	3.0 g/hp-hr
CO	2.6 g/hp-hr
PM, PM_{10}, $PM_{2.5}$	0.15 g/hp-hr
CO_2e	163 lb/MMBtu

Compliance Demonstration:
Compliance with the NO_X, CO, VOC, PM/PM_{10}/$PM_{2.5}$, and CO_2e emissions limitations for EU 62 shall be demonstrated by the work practice standards found in **1. Operating Limitations** (b. through e.).

b. Beginning with the model years in Table 3 to NSPS Subpart IIII (2009 for 400 HP engine), stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in Table 4 to NSPS Subpart IIII, for all pollutants, for the same model year and NFPA nameplate power. [40 CFR 60.4202(d)]

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 NSPS Subpart IIII, for all pollutants. [40 CFR 60.4205(c)]

Pollutant	Emission Limit
NMHC + NO_X	3.0 g/hp-hr
CO	2.6 g/hp-hr
PM	0.15 g/hp-hr

Compliance Demonstration:
Compliance with the NMHC, NO_X, CO, and PM emissions limitations for EU 62 shall be demonstrated by the work practice standards found in **1. Operating Limitations** (b. through e.).

3. Testing Requirements:

Testing shall be conducted at such times as may be requested by the Cabinet [401 KAR 50:045, Section 4].

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

4. Specific Monitoring Requirements:

a. The permittee shall monitor the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

b. The permittee shall monitor the hours of operation of the emergency fire pump [401 KAR 52:020, Section 10 and 40 CFR 60.4209(a)]

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of the amount of fuel (Mgal) used on a monthly basis. [401 KAR 52:020, Section 10]

b. The permittee shall maintain records of the hours of operation on a monthly basis. [401 KAR 52:020, Section 10]

c. The permittee shall meet the following recordkeeping requirements. [40 CFR 60.4214]

i. Keep records of the hours of operation of the engine in emergency and non-emergency operation if the engine is not certified to meet the non-emergency emissions standards. [40 CFR 60.4214(b)]

6. Specific Reporting Requirements:

See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 63 **Mechanical Draft Cooling Tower (10 Cells)**

Commented [MZ28]: KDAQ - Add new EU.

Description:

Maximum Continuous Rating:	95,000 gallons/minute (circulating water)
Control Device:	Drift Eliminators
Drift Rate:	0.001%
Construction Commenced:	TBD

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*
401 KAR 59:010, *New process operations*

1. **Operating Limitations:**
   a. The permittee shall minimize emissions of PM, PM_{10}, $PM_{2.5}$ through the use of inherent drift eliminators achieving 0.001% drift loss. [401 KAR 51:017]

   b. The cooling towers shall be operated and maintained according to the manufacturer's specifications and recommendations at all times. [401 KAR 52:020, Section 10]

   c. The use of chromium-based water treatment chemicals in the cooling tower is prohibited [To preclude 40 CFR 63, Subpart Q].

   Compliance Demonstration:

   Refer to subsections **5. Specific Recordkeeping Requirements**.

2. **Emission Limitations:**
   a. The permittee shall not emit any continuous emission into the open air from a control device or stack which is equal to or greater than 20 percent opacity. [401 KAR 59:010, Section 3(1)(a)].

   b. Particulate matter emissions shall not exceed the limit determined according to the following table, where P is the process weight rate in tons/hr and E is the maximum allowable emission rate in lbs/hr. [401 KAR 59:010, Section 3(2)]

P = Process Rate (tons/hr)	E = Particulate Emission Limit (lb/hr)
$P \leq 0.50$	$E = 2.34$
$0.50 < P \leq 30$	$E = 3.59*P^{0.62}$
$P > 30$	$E = 17.31*P^{0.16}$

   Compliance Demonstration:
   The permittee is assumed to be in compliance when the cooling towers are operated and maintained in accordance with the manufacturer's specifications and recommendations.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. **Testing Requirements:**
   Testing shall be conducted as required by the Cabinet [401 KAR 50:045, Section 1].

4. **Specific Monitoring Requirements:**
   a. The permittee shall monitor the total dissolved solids content of the circulating water on a monthly basis [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**
   a. The permittee shall maintain records of the maximum pumping capacity and monthly records of the total dissolved solids content. [401 KAR 52:020, Section 10].

   b. The permittee shall maintain records of the maintenance performed and use of the drift eliminators for the cooling tower [401 KAR 52:020, Section 10].

   c. The permittee shall keep onsite, and in a form suitable and readily available for expeditious review, the manufacturer's specifications for the cooling towers, including the drift rate [401 KAR 52:020, Section 10].

   d. The permittee shall maintain records of water treatment chemical purchases, including invoices and other documentation that includes invoices and other documentation that includes date(s) of purchase or shipment, trade name or other information to identify composition of the product, and quantity of the product [To preclude 40 CFR 63, Subpart Q].

6. **Specific Reporting Requirements:**
   See **Section F – Monitoring, Recordkeeping, and Reporting Requirements**.

7. **Specific Control Equipment Operating Conditions:**
   a. See **Section E – Source Control Equipment Requirements** for further requirements.

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 64 **Circuit Breaker**

Commented [MZ29]: KDAQ - Add new EUs.

Description: Turbine Circuit Breaker with SF6 circuit
Maximum Capacity: 30 lb.
Control Device: N/A
Construction Commenced: June 2026

Emission Unit 65 **Lube Oil System**

Description: Lube Oil System
Control Device: Demister System
Construction Commenced: June 2026

Emission Unit 66 & 67 **Storage Tanks**

Emission Unit	Description	Construction Commenced	Maximum Capacity	Fuel
66	Emergency Generator Diesel Storage Tank	June 2026	3,733 gallons	Diesel
67	Pump Diesel Storage Tank	June 2026	300 gallons	Diesel

Emission Unit 69 **Natural Gas Piping Fugitives**

Description: Equipment leak components associated with natural gas piping
Control Device: AVO Inspections
Construction Commenced: June 2026

Emission Unit 70 **Sulfuric Acid Storage Tank**

Description: Storage tank storing an aqueous solution of sulfuric acid
Maximum Capacity: 12,200 gal
Control Device: N/A
Construction Commenced: June 2026

APPLICABLE REGULATIONS:
401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. **Operating Limitations:**
   a. The permittee shall maintain the diesel storage tanks (EU 66 and EU 67) and the sulfuric acid tank (EU70) in good operating condition. [401 KAR 51:017]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b. The permittee shall conduct weekly auditory, visual, and olfactory inspections for the presence of natural gas leaks from EU 69, and promptly repair any detected leaks. [401 KAR 51:017]

Compliance Demonstration:
Compliance shall be demonstrated according to **5. Specific Recordkeeping Requirements** a.

2. Emission Limitations:

a. The permittee shall limit the SF6 leak rate from EU 64 to no more than 0.5 percent of the total charge on an annual average basis. [401 KAR 52:020, Section 10]

Compliance Demonstration:
Compliance shall be demonstrated according to **5. Specific Recordkeeping Requirements** b.

3. Testing Requirements:
None

4. Specific Monitoring Requirements:
None

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records for the natural gas leak inspections. [401 KAR 52:020, section 10]

b. The permittee shall maintain records from the leak rate calculations from EU 64 on an annual average. [401 KAR 52:020, section 10]

6. Specific Reporting Requirements:
None

7. Specific Control Equipment Operating Conditions:
None

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 68 **NGCC Paved Haul Roads**

Commented [MZ30]: KDAQ - Please add new EU.

Description: NGCC Plant Paved Roadways used as Haul Roads
Control Device: Wet suppression as needed
Construction Commenced: TBD

APPLICABLE REGULATIONS:
401 KAR 63:010, *Fugitive emissions*
401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. Operating Limitations:

a. The permittee shall not cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following: [401 KAR 63:010, Section 3(1)]

i. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land; [401 KAR 63:010, Section 3(1)(a)]

ii. Application and maintenance of asphalt, oil, water, or suitable chemicals on roads, materials stockpiles, and other surfaces which can create airborne dusts; [401 KAR 63:010, Section 3(1)(b)]

iii. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling. Adequate containment methods shall be employed during sandblasting or similar operations. [401 KAR 63:010, Section 3(1)(c)]

iv. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; [401 KAR 63:010, Section 3(1)(d)]

v. The maintenance of paved roadways in a clean condition; [401 KAR 63:010, Section 3(1)(e)]

vi. The prompt removal of earth or other material from a paved street which earth or other material has been transported thereto by trucking or earth moving equipment or erosion by water. [401 KAR 63:010, Section 3(1)(f)]

b. To ensure roadway emissions from truck traffic are minimized, the permittee shall employ a combination of the following to control fugitive dust emissions as outlined in a dust control plan: surface improvements (pavement), watering (good work practice), and/or other control methods (dust suppression systems, good housekeeping practices, etc.) as needed, but at

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

least monthly. [401 KAR 52:020, Section 10, 401 KAR 51:017]

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements** and **5. Specific Recordkeeping Requirements**.

2. Emission Limitations:

a. The permittee shall not cause, suffer, or allow visible fugitive dust emissions beyond the lot line of the property on which the emissions originate, as determined by Reference Method 22 of Appendix A in 40 C.F.R. Part 60, for: [401 KAR 63:010, Section 3(2)]

i. More than five (5) minutes of emission time during any sixty (60) minute observation period; or [401 KAR 63:010, Section 3(2)(a)]

ii. More than twenty (20) minutes of emission time during any twenty-four (24) hour period. [401 KAR 63:010, Section 3(2)(b)]

Compliance Demonstration:
Compliance shall be demonstrated according to **4. Specific Monitoring Requirements** and **5. Specific Recordkeeping Requirements**.

3. Testing Requirements:

a. Testing shall be conducted at such times as may be requested by the Cabinet. [401 KAR 50:045, Section 1]

b. If fugitive dust emissions beyond the lot line of the property are observed, conduct Reference Method 22 (visual determination of fugitive emissions) observations per Appendix A of 40 CFR Part 60. In lieu of conducting US EPA Reference Method 22, immediately perform a corrective action which results in no visible fugitive dust emissions beyond the lot line of the property. [401, KAR 52:020, Section 10, 401 KAR 63.010, Section 3(2)]

4. Specific Monitoring Requirements:

a. The permittee shall monitor the rate of material hauled (in tons, VMT, gallons/hr, etc.) for each unit or vehicle on the paved roadways on a monthly basis. [401 KAR 52:020, Section 10]

b. The permittee shall monitor actions taken to prevent the discharge of visible fugitive emissions beyond the property line, including the application of wet suppression. [401 KAR 52:020, Section 10, 401 KAR 63:010, Section 3(1)]

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SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

5. Specific Recordkeeping Requirements:

a. Maintain a log of the reasonable precautions taken to prevent particulate matter from becoming airborne on a daily basis. Notation of the operating status, down-time, or relevant weather conditions are acceptable for entry to the log. [401 KAR 52:020, Section 10]

b. The permittee shall maintain a log of the following: [401 KAR 52:020, Section 10]

i. Qualitative fugitive emissions observations conducted daily including the date, time, initials of observer, whether any fugitive dust emissions were observed,

ii. Any Reference Method 22 performed and field records identified in Reference Method 22.

iii. Any corrective action taken and the results.

6. Specific Reporting Requirements:

See **Section F – Monitoring, Recordkeeping, and Reporting Requirements**.

7. Specific Control Equipment Operating Conditions:

See **Section E – Source Control Equipment Requirements**.

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SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. Although these activities are designated as insignificant the permittee must comply with the applicable regulation. Process and emission control equipment at each insignificant activity subject to an opacity standard shall be inspected monthly and a qualitative visible emissions evaluation made. Results of the inspection, evaluation, and any corrective action shall be recorded in a log.

	Description	Generally Applicable Regulation
1.	Station fuel-oil tanks (2 @ 1,100,000 gallons each)	None
2.	#2 Fuel Oil tank Storage & Light-off for Unit 3 (525,000 gallons) installed 1973	None
3.	Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each)	None
4.	Unleaded gasoline storage tanks	None
5.	Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons)	None
6.	Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons)	None
7.	Burning of Off-Specification Used Oil for Energy Recovery	401 KAR 61:020
8.	Kerosene Tank (500 gallons)	None
9.	Distillate Oil and/or Propane Coal Belt Heaters	None
10.	Limestone Storage Pile	401 KAR 63:010
11.	Limestone Reclaim Maintenance Tunnel Exhaust Vent	401 KAR 59:010
12.	Sorbent Storage Silos (for SO_3 mitigation)	401 KAR 59:010
13.	Natural Gas Distillate tank (2,000 gallons)	None
14.	Diesel Fuel tanks for emergency generators (3 @ 391 gallons)	None
15.	Diesel Fuel tank for emergency fire pump (300 gallons)	None
16.	Liquid Hg Control Additives	None
17.	Diesel Fuel tank for emergency generator (837 gallons)	None
18.	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 440 gallons)	None
19.	Diesel Fuel tanks for emergency fire pumps & FGD building (2 @ 550 gallons)	None
20.	Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons)	None
21.	Turbine oil reservoir for Unit 3 seal oil (150 gallons)	None
22.	Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons)	None
23.	Lab Fume Hood	None
24.	Hydraulic oil, 30W and 40W oil tanks (2 @ 300 and 40W tank 1 @ 560 gallons)	None
25.	PAC Storage Silos	401 KAR 59:010
26.	Bottom Ash Transport	401 KAR 63:010
27.	Fly Ash Transport	401 KAR 63:010
28.	Gypsum Transport & Process Water System Solids	401 KAR 63:010
29.	Landfill Truck Loading and Unloading & Process Water System Solids	401 KAR 63:010
30.	Active Area of the CCR Landfill (Wind Erosion) & Process Water System Solids	401 KAR 63:010

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SECTION C - INSIGNIFICANT ACTIVITIES (CONTINUED)

31. Slipstream Carbon Dioxide (CO_2) capture System – Research	401 KAR 63:010
32. Bottom Ash Handling including storage pile (associated with CCR landfill operations)	401 KAR 63:010
33. Fly Ash Handling including load out to trucks (associated with CCR landfill operations)	401 KAR 63:010
34. Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)	401 KAR 63:010
35. Fly Ash Storage Silos (2) (associated with CCR landfill operations)	401 KAR 63:010, 401 KAR 59:010
36. Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)	401 KAR 63:010
37. NG Catalytic Heaters (2 @ 0.0025 MMBtu/hr, 5 @ 0.005 MMBtu/hr)	None
38. Diesel Fuel Tanks for emergency generators (2 @ 900 gallons)	None
39. Diesel Fuel Tanks (500, 2000, 3@ 550, 1,100 gallons) T-19 (Limestone Pile Equip Refueling) T-24, T-35 (Coal Yard) T-36, T-37 (Landfill) T-38 (Carey Farm)	None
40. Mobile Diesel Fuel Tank (251 gallons/square tank) T-39 (Stored in CT Warehouse when not in use)	None
41. Unit 3 Propylene Glycol Tank (3,000 gal)	None
42. Hydroelectric Building Lube Oil Tanks (T-31 and T-32)	None
43. CT Plant Maintenance Shop Parts Washer (Non-VOC Solvent)	None
44. Unit 3 Hydrazine Monohydrate Tote (180 gal)	None
45. Crusher House Cleanup Operations (Vacuum Recycle System and Recovery Cyclone)	401 KAR 59:010

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SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

1. As required by Section 1b of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26; compliance with annual emissions and processing limitations contained in this permit, shall be based on emissions and processing rates for any twelve (12) consecutive months.

2. Particulate matter, sulfur dioxide, nitrogen dioxide, VOC, carbon monoxide, and beryllium emissions, measured by applicable reference methods, or an equivalent or alternative method specified in 40 C.F.R. Chapter I, or by a test method specified in the state implementation plan shall not exceed the respective limitations specified herein.

3. No owner or operator shall allow any affected facility to emit potentially hazardous matter or toxic substances in such quantities or duration as to be harmful to the health and welfare of humans, animals and plants. The permittee is in compliance with these requirements based on the rates of emissions of airborne toxics provided in the application submitted by the permittee. If the permittee alters processes, process rates, material formulations, or any other factor that would result in increased emissions of airborne toxics, the permittee shall submit the appropriate application forms pursuant to 401 KAR 52:020, Section 3(1)(a) [401 KAR 63:020, Section 3].

4. Natural gas sulfur content will be specified by a purchase contract, tariff sheet, or by a pipeline transportation contract. Alternatively, sulfur content may be determined by representative fuel sampling data using the procedures in Appendix D to 40 CFR Part 75.

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SECTION E - SOURCE CONTROL EQUIPMENT REQUIREMENTS

Pursuant to 401 KAR 50:055, Section 2(5), 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 Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

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SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

1. Pursuant to Section 1b-IV-1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26, when continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:
   a. Date, place as defined in this permit, and time of sampling or measurements;
   b. Analyses performance dates;
   c. Company or entity that performed analyses;
   d. Analytical techniques or methods used;
   e. Analyses results; and
   f. Operating conditions during time of sampling or measurement.

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division for Air Quality, shall be retained by the permittee for a period of five (5) years and shall be made available for inspection upon request by any duly authorized representative of the Division for Air Quality [Sections 1b-IV-2 and 1a-8 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. In accordance with the requirements of 401 KAR 52:020, Section 3(1)h, the permittee shall allow authorized representatives of the Cabinet to perform the following during reasonable times:
   a. Enter upon the premises to inspect any facility, equipment (including air pollution control equipment), practice, or operation;
   b. To access and copy any records required by the permit:
   c. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements.

   Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit shall be submitted to the Regional Office listed on the front of this permit at least every six (6) months during the life of this permit, unless otherwise stated in this permit. For emission units that were still under construction or which had not commenced operation at the end of the 6-month period covered by the report and are subject to monitoring requirements in this permit, the report shall indicate that no monitoring was performed during the previous six months because the emission unit was not in operation [Sections 1b-V-1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

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SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

6. The semi-annual reports are due by January 30th and July 30th of each year. All reports shall be certified by a responsible official pursuant to 401 KAR 52:020, Section 23. If continuous emission and opacity monitors are required by regulation or this permit, data shall be reported in accordance with the requirements of 401 KAR 59:005, General Provisions, Section 3(3). All deviations from permit requirements shall be clearly identified in the reports.

7. In accordance with the provisions of 401 KAR 50:055, Section 1, the owner or operator shall notify the Regional Office listed on the front of this permit concerning startups, shutdowns, or malfunctions as follows:
   a. When emissions during any planned shutdowns and ensuing startups will exceed the standards, notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shut down, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.
   b. When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards, notification shall be made as promptly as possible by telephone (or other electronic media) and shall be submitted in writing upon request.

8. The permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken shall be submitted to the Regional Office listed on the front of this permit. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. Where the underlying applicable requirement does not identify a specific time frame for reporting deviations, prompt reporting, as required by Sections 1b-V, 3 and 4 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26, shall be defined as follows:
   a. For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in an applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence.
   b. For emissions of any regulated air pollutant, excluding those listed in F.8.a., that continue for more than two hours in excess of permit requirements, the report must be made within 48 hours.
   c. All deviations from permit requirements, including those previously reported, shall be included in the semiannual report required by F.6.

9. Pursuant to 401 KAR 52:020, Title V permits, Section 21, the permittee shall annually certify compliance with the terms and conditions contained in this permit, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an alternative approved by the regional office) to the Regional Office listed on the front of this permit and the U.S. EPA in accordance with the following requirements:
   a. Identification of the term or condition;
   b. Compliance status of each term or condition of the permit;
   c. Whether compliance was continuous or intermittent;
   d. The method used for determining the compliance status for the source, currently and over the reporting period.

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SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

e. For an emissions unit that was still under construction or which has not commenced operation at the end of the 12-month period covered by the annual compliance certification, the permittee shall indicate that the unit is under construction and that compliance with any applicable requirements will be demonstrated within the timeframes specified in the permit.

f. The certification shall be submitted by January 30th of each year. Annual compliance certifications shall be sent to the following addresses:

Division for Air Quality
Frankfort Regional Office
300 Sower Boulevard, 1st Floor
Frankfort, KY 40601

U.S. EPA Region 4
Air Enforcement Branch
Atlanta Federal Center
61 Forsyth St. SW
Atlanta, GA 30303-8960

10. In accordance with 401 KAR 52:020, Section 22, the permittee shall provide the Division with all information necessary to determine its subject emissions within 30 days of the date the Kentucky Emissions Inventory System (KYEIS) emissions survey is mailed to the permittee.

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SECTION G - GENERAL PROVISIONS

1. General Compliance Requirements

   a. The permittee shall comply with all conditions of this permit. Noncompliance shall be a violation of 401 KAR 52:020, Section 3(1)(b), and a violation of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act). Noncompliance with this permit is grounds for enforcement action including but not limited to termination, revocation and reissuance, revision or denial of a permit [Section 1a-3 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

   b. The filing of a request by the permittee for any permit revision, revocation, reissuance, or termination, or of a notification of a planned change or anticipated noncompliance, shall not stay any permit condition [Section 1a-6 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

   c. This permit may be revised, revoked, reopened and reissued, or terminated for cause in accordance with 401 KAR 52:020, Section 19. The permit will be reopened for cause and revised accordingly under the following circumstances:
      (1) If additional applicable requirements become applicable to the source and the remaining permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the permit is due to expire, unless this permit or any of its terms and conditions have been extended pursuant to 401 KAR 52:020, Section 12;
      (2) The Cabinet or the United States Environmental Protection Agency (U. S. EPA) determines that the permit must be revised or revoked to assure compliance with the applicable requirements;
      (3) The Cabinet or the U. S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;
      (4) New requirements become applicable to a source subject to the Acid Rain Program.

      Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable. Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Division, at least thirty (30) days in advance of the date the permit is to be reopened, except that the Division may provide a shorter time period in the case of an emergency.

   d. The permittee shall furnish information upon request of the Cabinet to determine if cause exists for modifying, revoking and reissuing, or terminating the permit; or to determine compliance with the conditions of this permit [Sections 1a- 7 and 8 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

   e. Emission units described in this permit shall demonstrate compliance with applicable requirements if requested by the Division [401 KAR 52:020, Section 3(1)(c)].

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SECTION G - GENERAL PROVISIONS (CONTINUED)

f. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information to the permitting authority [401 KAR 52:020, Section 7(1)].

g. Any condition or portion of this permit which becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit [Section 1a-14 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

h. The permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance [Section 1a-4 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

i. All emission limitations and standards contained in this permit shall be enforceable as a practical matter. All emission limitations and standards contained in this permit are enforceable by the U.S. EPA and citizens except for those specifically identified in this permit as state-origin requirements. [Section 1a-15 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

j. This permit shall be subject to suspension if the permittee fails to pay all emissions fees within 90 days after the date of notice as specified in 401 KAR 50:038, Section 3(6) [Section 1a-10 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

k. Nothing in this permit shall alter or affect the liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance [401 KAR 52:020, Section 11(3) b.].

l. This permit does not convey property rights or exclusive privileges [Section 1a-9 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

m. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Cabinet or any other federal, state, or local agency.

n. Nothing in this permit shall alter or affect the authority of U.S. EPA to obtain information pursuant to Federal Statute 42 USC 7414, Inspections, monitoring, and entry [401 KAR 52:020, Section 11(3) d.].

o. Nothing in this permit shall alter or affect the authority of U.S. EPA to impose emergency orders pursuant to Federal Statute 42 USC 7603, Emergency orders [401 KAR 52:020, Section 11(3) a.].

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SECTION G - GENERAL PROVISIONS (CONTINUED)

p. This permit consolidates the authority of any previously issued PSD, NSR, or Synthetic Minor source preconstruction permit terms and conditions for various emission units and incorporates all requirements of those existing permits into one single permit for this source.

q. Pursuant to 401 KAR 52:020, Section 11, a permit shield shall not protect the owner or operator from enforcement actions for violating an applicable requirement prior to or at the time of permit issuance. Compliance with the conditions of this permit shall be considered compliance with:
(1) Applicable requirements that are included and specifically identified in this permit; and
(2) Non-applicable requirements expressly identified in this permit.

2. Permit Expiration and Reapplication Requirements

a. This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the Division at least six (6) months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division [401 KAR 52:020, Section 12].

b. The authority to operate granted shall cease to apply if the source fails to submit additional information requested by the Division after the completeness determination has been made on any application, by whatever deadline the Division sets [401 KAR 52:020, Section 8(2)].

3. Permit Revisions

a. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the State Implementation Plan (SIP) or in applicable requirements and meet the relevant requirements of 401 KAR 52:020, Section 14(2).

b. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division for Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority within ten (10) days following the transfer.

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SECTION G - GENERAL PROVISIONS (CONTINUED)

4. Construction, Start-Up, and Initial Compliance Demonstration Requirements

Pursuant to a duly submitted application the Kentucky Division for Air Quality hereby authorizes the construction of and modifications to the equipment described herein in accordance with the terms and conditions of this permit (V-17-030 R2): EU 58 (Unit 12 Gas Turbine with HRSG); EU 59 (Auxiliary Boiler); EU 60 (Fuel Gas Dewpoint Heater); EU 61 (Diesel Emergency Generator); EU 62 (Diesel Driven Fire Pump); EU 63 (Mechanical Draft Cooling Tower); EU 64 (Circuit Breaker); EU 65 (Lube Oil System); EU 66 (Two Diesel Storage Tanks (EU 66 and EU 67); EU 68 (NGCC Haul Roads); EU 69 (NG Piping Fugitives); and EU 70 (Sulfuric Acid Tank).

a. Construction of any process and/or air pollution control equipment authorized by this permit shall be conducted and completed only in compliance with the conditions of this permit.

b. Within thirty (30) days following commencement of construction and within fifteen (15) days following start-up and attainment of the maximum production rate specified in the permit application, or within fifteen (15) days following the issuance date of this permit, whichever is later, the permittee shall furnish to the Regional Office listed on the front of this permit in writing, notification of the following:
   (1) The date when construction commenced.
   (2) The date of start-up of the affected facilities listed in this permit.
   (3) The date when the maximum production rate specified in the permit application was achieved.

c. Pursuant to 401 KAR 52:020, Section 3(2), unless construction is commenced within eighteen (18) months after the permit is issued, or begins but is discontinued for a period of eighteen (18) months or is not completed within a reasonable timeframe then the construction and operating authority granted by this permit for those affected facilities for which construction was not completed shall immediately become invalid. Upon written request, the Cabinet may extend these time periods if the source shows good cause.

d. Pursuant to 401 KAR 50:055, Section 2(1)(a), an owner or operator of any affected facility subject to any standard within the administrative regulations of the Division for Air Quality shall demonstrate compliance with the applicable standard(s) within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of such facility. Pursuant to 401 KAR 52:020, Section 3(3)(c), sources that have not demonstrated compliance within the timeframes prescribed in 401 KAR 50:055, Section 2(1)(a), shall operate the affected facility only for purposes of demonstrating compliance unless authorized under an approved compliance plan or an order of the cabinet.

e. This permit shall allow time for the initial start-up, operation, and compliance demonstration of the affected facilities listed herein. However, within sixty (60) days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities, the permittee shall conduct a performance demonstration on the affected facilities in accordance with 401 KAR 50:055,

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SECTION G - GENERAL PROVISIONS (CONTINUED)

General compliance requirements. Testing must also be conducted in accordance with General Provisions G.5 of this permit.

f. Terms and conditions in this permit established pursuant to the construction authority of 401 KAR 51:017 or 401 KAR 51:052 shall not expire.

5. Testing Requirements

a. Pursuant to 401 KAR 50:045, Section 2, a source required to conduct a performance test shall submit a completed Compliance Test Protocol form, DEP form 6028, or a test protocol a source has developed for submission to other regulatory agencies, in a format approved by the cabinet, to the Division's Frankfort Central Office a minimum of sixty (60) days prior to the scheduled test date. Pursuant to 401 KAR 50:045, Section 7, the Division shall be notified of the actual test date at least thirty (30) days prior to the test.

b. Pursuant to 401 KAR 50:045, Section 5, in order to demonstrate that a source is capable of complying with a standard at all times, any required performance test shall be conducted under normal conditions that are representative of the source's operations and create the highest rate of emissions. If [When] the maximum production rate represents a source's highest emissions rate and a performance test is conducted at less than the maximum production rate, a source shall be limited to a production rate of no greater than 110 percent of the average production rate during the performance tests. If and when the facility is capable of operation at the rate specified in the application, the source may retest to demonstrate compliance at the new production rate. The Division for Air Quality may waive these requirements on a case-by-case basis if the source demonstrates to the Division's satisfaction that the source is in compliance with all applicable requirements.

c. Results of performance test(s) required by the permit shall be submitted to the Division by the source or its representative within forty-five days or sooner if required by an applicable standard, after the completion of the fieldwork.

6. Acid Rain Program Requirements

a. If an applicable requirement of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act) is more stringent than an applicable requirement promulgated pursuant to Federal Statute 42 USC 7651 through 7651o (Title IV of the Act), both provisions shall apply, and both shall be state and federally enforceable.

b. The permittee shall comply with all applicable requirements and conditions of the Acid Rain Permit and the Phase II permit application (including the Phase II NOx compliance plan and averaging plan, if applicable) incorporated into the Title V permit issued for this source. The source shall also comply with all requirements of any revised or future acid rain permit(s) issued to this source.

7. Emergency Provisions

a. Pursuant to 401 KAR 52:020, Section 24(1), an emergency shall constitute an affirmative defense to an action brought for the noncompliance with the technology-based emission

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SECTION G - GENERAL PROVISIONS (CONTINUED)

limitations if the permittee demonstrates through properly signed contemporaneous operating logs or relevant evidence that:
(1) An emergency occurred and the permittee can identify the cause of the emergency;
(2) The permitted facility was at the time being properly operated;
(3) During an emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and
(4) Pursuant to 401 KAR 52:020, 401 KAR 50:055, and KRS 224.1-400, the permittee notified the Division as promptly as possible and submitted written notice of the emergency to the Division when emission limitations were exceeded due to an emergency. The notice shall include a description of the emergency, steps taken to mitigate emissions, and corrective actions taken.
(5) This requirement does not relieve the source of other local, state or federal notification requirements.

b. Emergency conditions listed in General Condition G.7.a above are in addition to any emergency or upset provision(s) contained in an applicable requirement [401 KAR 52:020, Section 24(3)].

c. In an enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof [401 KAR 52:020, Section 24(2)].

8. Ozone Depleting Substances

a. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:
(1) Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices contained in 40 CFR 82.156.
(2) Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment contained in 40 CFR 82.158.
(3) Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.155.
(5) Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156 and 40 CFR 82.157.
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

b. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, *Servicing of Motor Vehicle Air Conditioners*.

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SECTION G - GENERAL PROVISIONS (CONTINUED)

9. Risk Management Provisions

   a. The permittee shall comply with all applicable requirements of 401 KAR Chapter 68, Chemical Accident Prevention, which incorporates by reference 40 CFR Part 68, Risk Management Plan provisions. If required, the permittee shall comply with the Risk Management Program and submit a Risk Management Plan to U.S. EPA using the RMP* eSubmit software.

   b. If requested, submit additional relevant information to the Division or the U.S. EPA.

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SECTION H - ALTERNATE OPERATING SCENARIOS

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SECTION I - COMPLIANCE SCHEDULE

N/A

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SECTION J - ACID RAIN

1. **Statutory and Regulatory Authority**
In accordance with KRS 224.10-100 and Titles IV and V of the Clean Air Act, the Kentucky Environmental and Public Protection Cabinet, Division for Air Quality issues this permit pursuant to 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, and 40 CFR Part 76.

2. **Permit Requirements:**
This Acid Rain Permit covers Acid Rain Unit 3 (Emission Unit 03) and 5-11 (Emission Units 23-29) at the E.W. Brown plant (ORIS Code: 001355). Unit 3 is a coal-fired based load electric generating unit. Units 5-11 are natural gas- or distillate oil-fired peaking combustion turbines. The Acid Rain Permit Application and NO_X Compliance Plan received on March 1, 2010, for Phase II are hereby incorporated into and made part of this permit and the permittee must comply with the standard requirements and special provisions set forth in the application [40 CFR 72.9(a)(2)].

3. **Acid Rain Program Emission and Operating Limitations:**
(a) The applicable Acid Rain emission limitations for the permittee are as follows [40 CFR 73.10, Table 2, 40 CFR 76.5, and 40 CFR 76.11]:

Unit	Annual SO_2 Allowances	Emission Limitation (lb/MMBtu)	Annual Average NO_X ACEL (lb/MMBtu)	Annual Heat Input Limit, when complying with ACEL (MMBtu)
3	11,273	0.45	0.45	28,309,000
5	0	N/A	N/A	N/A
6	0	N/A	N/A	N/A
7	0	N/A	N/A	N/A
8	0	N/A	N/A	N/A
9	0	N/A	N/A	N/A
10	0	N/A	N/A	N/A
11	0	N/A	N/A	N/A

(b) The number of allowances allocated to Phase II affected units by the U.S. EPA may change under 40 CFR Part 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit. [40 CFR 72.84]

4. **Compliance Plan:**
(a) The permittee shall operate in compliance with the requirements contained in the Acid Rain application and incorporated into this permit [40 CFR 72.9].

(b) The Division approves the NO_X Average Plan submitted for these units for the NO_X Emissions Compliance Plan, effective for the duration of this permit. Under this plan, a unit's NO_X emissions shall not exceed the applicable annual average alternative contemporaneous emissions limitation (ACEL) listed in Subsection 3(a). [40 CFR 76]

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SECTION J - ACID RAIN PERMIT (CONTINUED)

(1) The actual Btu-weighted annual average NO_X emission rate for the units in the plan shall be less than or equal to the Btu-weighted annual average NO_X emission rate for the same units had they been operated, during the same period of time, in compliance with the individual applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7 and listed in Subsection 3(a).

(2) For each unit, if the designated representative demonstrates that the requirement of Subsection 4(b)(1) is met for the plan year, then the unit shall be deemed to be in compliance for the year with its ACEL and associated heat input limit in Subsection 3.

(3) If the designated representative cannot make the demonstration in Subsection 4(b)(1), according to 40 CFR 76.11(d)(1)(ii)(A), for the plan year and if a unit fails to meet the annual average ACEL or has a heat input greater than the applicable value listed in Subsection 3, then excess emissions of NO_X have occurred during the year for that unit.

(4) In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_X compliance plan and requirements covering excess emissions.

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SECTION K - CLEAN AIR INTERSTATE RULE (CAIR)

CSAPR implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule.

Commented [WJ31]: KDAQ - Can these items of Section K be removed, similar to the Section K found in LG&E Trimble County Title V operating permit (V-22-028)?

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SECTION L - CROSS-STATE AIR POLLUTION RULE

Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions at this source, are identified in the following tables. These units are subject to the requirements for the CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program

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
Unit ID: Emission Unit 3 (Unit 3)					
SO_2	X		----------		
NO_X	X	----------			
Heat input	X		----------		
Unit ID: Emission Unit 23 (Unit 9); Emission Unit 24 (Unit 10); Emission Unit 25 (Unit 8); Emission Unit 26 (Unit 11); Emission Unit 27 (Unit 6); Emission Unit 28 (Unit 7); Emission Unit 29 (Unit 5)					
SO_2		X	----------	X	
NO_X		----------	X		
Heat input	X		----------		
Unit ID: Emission Unit 58 (Unit 12, non-peaking natural-gas fired combustion turbine with natural gas-fired duct burners)					
SO_2		X			
NO_X	X				
Heat input		X			

Commented [WJ32]: KDAQ - We should have caught it in the application; but we are not using LME for SO2 on the simple cycle CTs. We have always been using 40 CFR 75 Appendix D.

Commented [WJ33]: KDAQ - Please remove "------" from the table.

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

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 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(30) (CSAPR NO_x Annual Trading Program), 40 CFR 97.830 through 40 CFR 97.835 (CSAPR NO_x Ozone Season Expanded Group 2 Trading Program), and 401 KAR 51:260 Section 3(25) through 401 KAR 51:260, Section 3(30) (CSAPR SO_2 Group 1 Trading Program). The monitoring, recordkeeping, and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR 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:

   http://www.epa.gov/airmarkets/emissions/ monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system shall submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR 75, Subpart E, 40 CFR 75.66, 401 KAR 51:240, Section 3(30) (CSAPR NO_X Annual Trading Program), 40 CFR 97.835 (CSAPR NO_X Ozone Season Expanded Group 2 Trading Program), and/or 401 KAR 51:260, Section 3(30) (CSAPR SO_2 Group 1 Trading Program). 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 requirements under 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(29) (CSAPR NO_x Annual Trading Program), 40 CFR 97.830 through 40 CFR 97.835 (CSAPR NO_x Ozone Season Expanded Group 2 Trading Program), and/or 401 KAR 51:260, Section 3(25) through 401 KAR 51:260, Section 3(29) (CSAPR SO_2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 401 KAR 51:240, Section 3(30) (CSAPR NO_x Annual Trading Program), 40 CFR 97.1035 (CSAPR SO_2 Group 1 Trading Program), and 40 CFR 97.835 (CSAPR NO_x Ozone Season Expanded Group 2 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/ petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(29) (CSAPR NO_x Annual Trading Program), 40 CFR 97.834 (CSAPR NO_x Ozone Season Expanded Group 2 Trading Program), and 401 KAR 51:260, Section 3(25) through 401 KAR 51:260, Section 3(29) (CSAPR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B), may be used to add or change this unit's monitoring system description.

CSAPR NO_x Annual Trading Program requirements (401 KAR 51:240, Section 3(4))

a) Designated representative requirements.

Commented [MZ34]: KDAQ - Many changes are needed here because of the Federal Register changes that have occurred in June and July of 2023. See 88 FR 36890, June 5, 2023; 88 FR 49303, July 31, 2023.

Commented [WJ35R34]: KDAQ - This is the same as previously noted...
With the stay of the SIP disapprovals, KY is not applicable to the Group 3 trading program.
With the Interim Final Rule, published on August 4, 2023, KY EGUs are now back in 40 CFR 97 Subpart EEEEE and operating in a new "Expanded G2" NOx ozone season trading program per 52.38(b)(14).
So it seems like all GGGGG references should be changed to appropriate EEEEE/Expanded G2 references, including the first sentence (above) of Section L.

Commented [MZ36R34]: (14) * * * (i) * * * (G) The provisions in § 97.526(e) of this chapter or § 97.826(f) of this chapter (concerning the use of CSAPR NOX Ozone Season Original Group 2 allowances, CSAPR NOX Ozone Season Expanded Group 2 allowances, or CSAPR NOX Ozone Season Group 3 allowances to satisfy requirements to hold CSAPR NOX Ozone Season Group 1 allowances or the use of CSAPR NOX Ozone Season Expanded Group 2 allowances or CSAPR NOX Ozone Season Group 3 allowances to satisfy requirements to hold CSAPR NOX Ozone Season Original Group 2 allowances)

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 401 KAR 51:240, Section 3(10) through 401 KAR 51:240, Section 3(15).

b) Emissions monitoring, reporting, and recordkeeping requirements.

1. The owners and operators, and the designated representative, of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 401 KAR 51:240, Section 3(25) (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 401 KAR 51:240, Section 3(26) (initial monitoring system certification and recertification procedures), 401 KAR 51:240, Section 3(27) (monitoring system out-of-control periods), 401 KAR 51:240, Section 3(28) (notifications concerning monitoring), 401 KAR 51:240, Section 3(29) (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 401 KAR 51:240, Section 3(30) (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
2. The emissions data determined in accordance with 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(30) shall be used to calculate allocations of CSAPR NO_x Annual allowances under 401 KAR 51:240, Section 3(8) (40 CFR 97.411(a)(2) and (b)) and 401 KAR 51:240, Section 3(9) and to determine compliance with the CSAPR NO_x Annual 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 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(30) and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c) NO_x emissions requirements.

1. CSAPR NO_x Annual emissions limitation.
   i. As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_x Annual allowances available for deduction for such control period under 401 KAR 51:240, Section 3(20) (40 CFR 97.424(a)) in an amount not less than the tons of total NO_x emissions for such control period from all CSAPR NO_x Annual units at the source.
   ii. If total NO_x emissions during a control period in a given year from the CSAPR NO_x Annual units at a CSAPR NO_x Annual source are in excess of the CSAPR NO_x Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:
      A) The owners and operators of the source and each CSAPR NO_x Annual unit at the source shall hold the CSAPR NO_x Annual allowances required for deduction under 401 KAR 51:240, Section 3(20) (40 CFR 97.424(d)); and
      B) The owners and operators of the source and each CSAPR NO_x 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 401 KAR 51:240 and the Clean Air Act.
2. CSAPR NO_x Annual assurance provisions.

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

i. If total NO_x emissions during a control period in a given year from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the state 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 NO_x 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) CSAPR NO_x Annual allowances available for deduction for such control period under 401 KAR 51:240, Section 3(21) (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 401 KAR 51:240, Section 3(21) (40 CFR 97.425(b)), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_x 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 state for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the state for such control period exceed the state assurance level.

ii. The owners and operators shall hold the CSAPR NO_x Annual allowances required under paragraph (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 NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_x emissions exceed the sum, for such control period, of the state NO_x Annual trading budget under 401 KAR 51:240, Section 3(7)(a)(1) and the state's variability limit under 401 KAR 51:240, Section 3(7)(a)(3).

iv. It shall not be a violation of 401 KAR 51:240, or of the Clean Air Act if total NO_x emissions from all CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_x emissions from the CSAPR NO_x Annual units at CSAPR NO_x Annual sources in the state during a control period exceeds the common designated representative's assurance level.

v. To the extent the owners and operators fail to hold CSAPR NO_x Annual allowances for a control period in a given year in accordance with paragraphs (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 CSAPR NO_x Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 401 KAR 51:240, and the Clean Air Act.

3. Compliance periods.

i. A CSAPR NO_x Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

meeting the unit's monitor certification requirements under 401 KAR 51:240, Section 3(25) (40 CFR 97.430(b)) and for each control period thereafter.

ii. A CSAPR NO_x Annual unit shall be subject to the requirements under paragraph (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 401 KAR 51:240, Section 3(25) (40 CFR 97.430(b)) and for each control period thereafter.

4. Vintage of allowances held for compliance.
   i. A CSAPR NO_x Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year shall be a CSAPR NO_x Annual allowance that was allocated for such control period or a control period in a prior year.
   ii. A CSAPR NO_x Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year shall be a CSAPR NO_x 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.
5. Allowance Management System requirements. Each CSAPR NO_x Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 401 KAR 51:240.
6. Limited authorization. A CSAPR NO_x Annual allowance is a limited authorization to emit one ton of NO_x 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 CSAPR NO_x Annual Trading Program; and
   ii. Notwithstanding any other provision of 40 CFR 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.
7. Property right. A CSAPR NO_x Annual allowance does not constitute a property right.

d) Title V permit revision requirements.

1) No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Annual allowances in accordance with 401 KAR 51:240.
2) This permit incorporates the CSAPR emissions monitoring, recordkeeping, and reporting requirements pursuant to 401 KAR 51:240, Section 3(25) through 401 KAR 51:240, Section 3(30), and the requirements for a continuous emission monitoring system (pursuant to 40 CFR 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this Title V permit using minor permit modification procedures in accordance with 401 KAR 51:240, Section 3(4) (40 CFR 97.406(d)(2)) and 70.7(e)(2)(i)(B).

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

e) Additional recordkeeping and reporting requirements.

1. Unless otherwise provided, the owners and operators of each CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall maintain 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 401 KAR 51:240, Section 3(13) for the designated representative for the source and each CSAPR NO_x 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 401 KAR 51:240, Section 3(13) changing the designated representative.
   ii. All emissions monitoring information, in accordance with 401 KAR 51:240.
   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 CSAPR NO_x Annual Trading Program.
2. The designated representative of a CSAPR NO_x Annual source and each CSAPR NO_x Annual unit at the source shall make all submissions required under the CSAPR NO_x Annual Trading Program, except as provided in 401 KAR 51:240, Section 3(15). 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 70.

f) Liability.

1) Any provision of the CSAPR NO_x Annual Trading Program that applies to a CSAPR NO_x Annual source or the designated representative of a CSAPR NO_x Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_x Annual units at the source.
2) Any provision of the CSAPR NO_x Annual Trading Program that applies to a CSAPR NO_x Annual unit or the designated representative of a CSAPR NO_x Annual unit shall also apply to the owners and operators of such unit.

g) Effect on other authorities.

No provision of the CSAPR NO_x Annual Trading Program or exemption under 401 KAR 51:240, Section 3(3) shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_x Annual source or CSAPR NO_x Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR NO_x Ozone Season Group 2 Trading Program Requirements (40 CFR 97 Subpart EEEEE)

a) 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 97.813 through 40 CFR 97.818.

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

b) Emissions monitoring, reporting, and recordkeeping requirements.

1. The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
2. The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season 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 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c) NO_x emissions requirements.

1. CSAPR NO_x Ozone Season Group 2 emissions limitation.
   i. As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.
   ii. If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:
      A) The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NO_X Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and
      B) The owners and operators of the source and each CSAPR NO_X Ozone Season 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 EEEEE and the Clean Air Act.
2. CSAPR NO_x Ozone Season Group 2 assurance provisions.

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

i. If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state 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 NO_X 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) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(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 97.825(b), of multiplying —
   A) The quotient of the amount by which the common designated representative's share of such NO_x 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 state for such control period, by which each common designated representative's share of such NO_x emissions exceeds the respective common designated representative's assurance level; and
   B) The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state for such control period exceed the state assurance level.

ii. The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (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 NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

iv. It shall not be a violation of 40 CFR part 97, subpart EEEEE or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state during a control period exceeds the common designated representative's assurance level.

v. To the extent the owners and operators fail to hold CSAPR NO_x Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (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 CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, subpart EEEEE and the Clean Air Act.

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

3. Compliance periods.
   i. A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.
   ii. A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.
4. Vintage of CSAPR NO_x Ozone Season Group 3 allowances held for compliance.
   i. A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.
   ii. A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Ozone Season 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.
5. Allowance Management System requirements. Each CSAPR NO_X Ozone Season 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 EEEEE.
6. Limited authorization. A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X 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 CSAPR NO_x Ozone Season Group 2 Trading Program; and
   ii. Notwithstanding any other provision of 40 CFR 97, Subpart EEEEE, 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.
7. Property right. A CSAPR NO_x Ozone Season Group 2 allowance does not constitute a property right.

d) Title V permit requirements.

1. No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_x Ozone Season Group 2 allowances in accordance with 40 CFR 97, Subpart EEEEE.

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

2. This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e) Additional recordkeeping and reporting requirements.

1. Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season 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 97.816 for the designated representative for the source and each CSAPR NO_x Ozone Season 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 97.816 changing the designated representative.
   ii. All emissions monitoring information, in accordance with 40 CFR 97, Subpart EEEEE.
   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 CSAPR NO_x Ozone Season Group 2 Trading Program.
2. The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. 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.

f) Liability.

1. Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NOX Ozone Season Group 2 units at the source.
2. Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

g) Effect on other authorities.

No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

Ozone Season 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.

CSAPR SO_2 Group 1 Trading Program requirements (401 KAR 51:260, Section 3(4))

a) 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 401 KAR 51:260, Section 3(10) through 401 KAR 51:260, Section 3(15).

b) Emissions monitoring, reporting, and recordkeeping requirements.

1. The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 401 KAR 51:260, Section 3(25) (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 401 KAR 51:260, Section 3(26) (initial monitoring system certification and recertification procedures), 401 KAR 51:260, Section 3(27) (monitoring system out-of-control periods), 401 KAR 51:260, Section 3(28) (notifications concerning monitoring), 401 KAR 51:260, Section 3(29) (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 401 KAR 51:260, Section 3(30) (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
2. The emissions data determined in accordance with 401 KAR 51:260, Section 3(25) through 401 KAR 51:260, Section 3(30) shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 401 KAR 51:260, Section 3(8) (40 CFR 97.611(a)(2)) and (b)) and 401 KAR 51:260, Section 3(9) and to determine compliance with the CSAPR SO_2 Group 1 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 401 KAR 51:260, Section 3(25) through 401 KAR 51:260, Section 3(30) and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c) SO_2 emissions requirements.

1. CSAPR SO_2 Group 1 emissions limitation.
   i. As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 401 KAR 51:260, Section 3(20) (40 CFR 97.624(a)) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.
   ii. If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:
      A) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 401 KAR 51:260, Section 3(20) (40 CFR 97.624(d)); and
      B) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

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 401 KAR 51:260, and the Clean Air Act.

2. CSAPR SO_2 Group 1 assurance provisions.
   i. If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state 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 SO_2 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) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 401 KAR 51:260, Section 3(21) (40 CFR 97.625(a)) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 401 KAR 51:260, Section 3(21) (40 CFR 97.625(b)), of multiplying—
      A) The quotient of the amount by which the common designated representative's share of such SO_2 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 state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and
      B) The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.
   ii. The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (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 SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 401 KAR 51:260, Section 3(7)(a)(1) and the state's variability limit under 401 KAR 51:260, Section 3(7)(a)(3).
   iv. It shall not be a violation of 401 KAR 51:260, or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.
   v. To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (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 CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

each day of such control period shall constitute a separate violation of 401 KAR 51:260, and the Clean Air Act.

3. Compliance periods.
   i. A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (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 401 KAR 51:260, Section 3(25) (40 CFR 97.630(b)) and for each control period thereafter.
   ii. A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (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 401 KAR 51:260, Section 3(25) (40 CFR 97.630(b)) and for each control period thereafter.
4. Vintage of allowances held for compliance.
   i. A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year shall be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.
   ii. A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year shall be a CSAPR SO_2 Group 1 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.
5. Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 401 KAR 51:260.
6. Limited authorization. CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 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 CSAPR SO_2 Group 1 Trading Program; and
   ii. Notwithstanding any other provision of 401 KAR 51:260, 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.
7. Property right. CSAPR SO_2 Group 1 allowance does not constitute a property right.

d) Title V permit revision requirements.

1. No Title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 401 KAR 51:260.
2. This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 401 KAR 51:260, Section 3(25) through 401 KAR 51:260, Section 3(30), and the requirements for a continuous emission monitoring system (pursuant to 40 CFR 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR 75, Subpart E), Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this Title V permit using minor permit modification procedures in accordance with 401 KAR 51:260, Section 3(4) (40 CFR 97.606(d)(2)) and 70.7(e)(2)(i)(B).

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SECTION L – CROSS-STATE AIR POLLUTION RULE (CONTINUED)

e) Additional recordkeeping and reporting requirements.

1. Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall maintain 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 401 KAR 51:260, Section 3(13) for the designated representative for the source and each CSAPR SO_2 Group 1 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 97.616 changing the designated representative.
   (ii). All emissions monitoring information, in accordance with 401 KAR 51:260.
   (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 CSAPR SO_2 Group 1 Trading Program.
2. The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 401 KAR 51:260, Section 3(15). 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 70.

f) Liability.

1. Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.
2. Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 401 KAR 51:260, Section 3(3) shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.