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a PPL company

December 15, 2022

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 is submitting the enclosed significant permit revision application to obtain an amended Title V Operating Permit authorizing the 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.

The NGCC Unit 12 will consist of one natural gas-fired gas 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. NGCC 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 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 control measures being used for NGCC Unit 12, combined with the emission reductions from the shutdown of the Unit 3 coal boiler, will result in a significant improvement in the air emissions profile for the Brown Generating Station. Following the implementation of the NGCC Project, there will be significant reductions in actual emission for NO_X, SO_2, and particulate matter. The significant decreases in NO_X emissions should contribute to reductions in regional ozone concentrations. Coupled with these significant environmental benefits, 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.

In recognition of U.S. EPA's current environmental justice policies, KU has performed certain environmental justice reviews. KU evaluated the Brown Generating Station and surrounding area using Version 1.0 of the Climate & Economic Justice Screening Tool. Brown Generating Station resides in tract number 21167960500 in Mercer County. This tract is not considered disadvantaged. It does not meet any burden or threshold or at least one associated socioeconomic threshold. This project has no significant impacts to the environment and will, in fact, result in environmental benefits because construction of a combined cycle natural gas generating unit will facilitate retirement of a higher emitting coal-fired generating unit at the site. Further, the project will provide economic benefit in the local community and reliable, affordable electric service to the KU customers generally.

Although currently there are no specific legal requirements mandating environmental justice review as part of the state review process, we opted to perform the above-referenced environmental justice review in order to be both proactive and transparent.

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 **October 1, 2023**.

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,

DocuSigned by:
Brandan Burfict
275A1971A06448A...

Brandan Burfict
Manager, Environmental Air

Enclosure

cc: Mr. Philip Imber, Director, Environmental and Federal Regulatory Compliance, KU
Ms. Marlene Zeckner Pardee, Senior Environmental Scientist, KU
Mr. Jason Wilkerson, Senior Environmental Engineer, KU
Mr. Sean Bottoms, Manager, Operations & Maintenance, Brown Generating Station, KU
Mr. Steven Turner, Vice President Power Production, LG&E and KU Energy
Mr. Paul J. Smith, P.E., Director, Trinity Consultants
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TITLE V AIR PERMIT REVISION APPLICATION

New NGCC Combustion Turbine Project

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

Agency Interest # **3148**

December 15, 2022

Prepared By:

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Project 221801.0123

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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 and currently operates in accordance 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. The permit authorizes the operation of a coal-fired utility boiler (Unit 3); seven combustion turbines; natural gas (NG)-fired heat exchangers; coal, limestone, fly ash, coal combustion residue, carbon, and gypsum handling and storage operations; a cooling tower, emergency equipment; miscellaneous organic liquids tanks; general plant fugitive emissions; and numerous insignificant activities.

1.1 Purpose of Application

In accordance with 401 KAR 52:020, KU is submitting this significant permit revision application to obtain an amended Title V Operating Permit authorizing the 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. KU will utilize and optimize the current electrical transmission system, as well as tap into an existing natural gas pipeline on the property to serve the new NGCC Unit.

The new NGCC Unit proposed will consist of one natural gas-fired gas combustion turbine (GT), one steam turbine (ST), and one heat recovery steam generator (HRSG) with natural gas-fired duct burners (DB) arranged in a one-on-one configuration. Ancillary support equipment will also be installed to support the NGCC Unit operations, including one natural gas-fired boiler (Auxiliary Boiler) rated at 99.9 million British thermal units per hour (MMBtu/hr) or less, one pipeline fuel gas (dewpoint) heater rated at 15 MMBtu/hr or less, one 2 megawatts (MW) emergency generator with diesel-fired engine, one 400 horsepower (HP) emergency diesel driven fire pump engine, and one 8-cell mechanical draft cooling tower.

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). The facility is currently classified as an existing major source under the Prevention of Significant Deterioration (PSD) permitting program. Since the new NGCC Unit 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; hence, the NGCC Project will be considered a modification to an existing major stationary source. Therefore, the applicability of the proposed NGCC Project to the PSD permitting regulations is evaluated.

As documented within this application, the total NGCC Project emission increases, consisting of the sum of the differences of potential emissions from new emission units and the differences between projected actual and baseline actual emissions for existing emission units, is above the New Source Review (NSR) "major modification" threshold for all relevant regulated NSR pollutants except lead.[1] However, after accounting for the creditable emission increases and decreases in the contemporaneous period, the net project emission increases for all pollutants will not be significant, and therefore the NGCC Project does not trigger PSD permitting requirements (i.e., it is not subject to Sections 8 to 16 of 401 KAR 51:017). For the emission

[1] Relevant regulated NSR pollutants for the NGCC Project are 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), sulfur dioxide (SO_2), sulfuric acid (H_2SO_4) mists, lead (Pb), and greenhouse gases (GHG).

decreases within the contemporaneous period associated with the shutdown of Unit 3, KU is proposing to establish an operating limit to make this shutdown enforceable and concurrent with the commercial operation of the NGCC Unit.

Emission units associated with the new NGCC 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 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 NGCC Project.

1.2 Project Schedule

KU is targeting for commercial operation of new NGCC Unit to begin no later than April 1, 2028. Given that the construction and commissioning of the NGCC Unit is expected to last 37 months, the anticipated start of construction will be March 1, 2025. 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 **October 1, 2023**.

1.3 Summary of Application Contents

This application package, consisting of this report and four appendices is organized as follows:

- Section 2 provides relevant background information about the Brown Generating Station and information about the proposed new NGCC Unit 12 operations and existing operations that are being shut down as part of the project.
- Section 3 discusses the emissions calculation methodologies used to define the potential emissions from the new emission units/ancillary equipment associated with the NGCC 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 Project.
- 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 and the existing units being shut down as part of the project.
- Appendix B provides an inventory of the existing and new proposed emission units at Brown Generating Station; a derivation of potential emissions from the new emission units associated with the NGCC Project; and the baseline actual emissions for existing emission units that are being shut down as part of the NGCC Project.

- Appendix C provides all the 7007 Series air permit application forms required for processing of this application along with a copy of the acid rain program revision application for the project.
- Appendix D provides sample suggested edits to the existing Title V permit encompassing the regulatory and permitting requirements impacted by the NGCC Project.

2. PROJECT DESCRIPTION

This section describes the proposed NGCC Project that will be installed and operated at the existing E.W. Brown Generating 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).

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. A process flow diagram showing the configuration on the air pollution controls and continuous monitoring systems is provided in Figure A-6 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 GTs.

2.3 Proposed New Operations

Brown Generating Station's coal-fired Unit 3 is reaching the end of its economic life and over the last few years, KU began the process of evaluating all available generation options to meet the energy demands of its customers. KU plans to construct and operate a new 664 MW (net) natural gas-fired NGCC Unit by 2028 at Brown Generating Station in conjunction with the retirement of Unit 3. KU will utilize and optimize the current electrical transmission system, as well as tap into an existing natural gas pipeline on the property to serve the new NGCC Unit.

While Brown Generating Station has multiple pathways for generating electricity for its customers, with the retirement of the last remaining coal-fired unit (464 MW), KU has chosen to add NGCC Unit 12 (COMB19/58) as a new asset due to its ability to operate as a base loaded unit, its ability to be quickly and efficiently dispatched when renewables are not available, and when there is sudden high demand from industrial customers.

As part of the NGCC Project, the following new air emissions units will be installed:

- NG-fired combined cycle power plant with one combustion turbine (GT) (7HA.03, 501JAC, 9000HL, or similar), one HRSG equipped with NG-fired DBs, and one ST arranged in a one-on-one configuration.
- Auxiliary Boiler using NG and a rated higher heating value (HHV) heat input capacity of 99.9 MMBtu/hr
- Fuel Gas (Dewpoint) Heater using NG with a heat input capacity of 15 MMBtu/hr
- 2000 kW (2,682 nominal brake horsepower[bhp]) emergency generator with diesel-fired engine (U.S. EPA Certified Tier 2) and associated diesel storage tank
- 400 bhp emergency diesel driven fire pump engine (U.S. EPA Certified Tier 3) and associated diesel storage tank
- Mechanical draft cooling tower (8 Cell)
- Lube oil system demister vents
- Ancillary equipment, including raw and demineralized water storage tanks; aqueous ammonia storage and handling equipment; and miscellaneous HVAC heaters

A process flow diagram showing the proposed NGCC Unit operations is provided in Figure A-6 in Appendix A, and each of the air emission units is discussed in the following subsections. Figure A-3 shows an overlay of the planned location of the new NGCC Unit operations on an existing aerial image of the Brown Generating Station. The same equipment layout location is shown on a facility site diagram in Figure A-4. Finally, Figure A-5 provides a detailed arrangement of the proposed new NGCC Project emission units and associated structures.

KU is currently in the process of evaluating and selecting the primary vendor that will provide the core NGCC Unit equipment and a final selection will not be made until farther in the project development process. There are currently three primary vendors being evaluated that are correspondingly referred to in this application as Vendor A, Vendor B, or Vendor C. KU has provided a set of minimum equipment specifications and emissions performance guarantees that must be met by each vendor. Because the operating scenarios and potential emissions represented in this permit application encompass the worst-case combination of the data and parameters provided by each vendor for their equipment packages, the regulatory and permit applicability review can be completed without yet knowing which specific vendor will ultimately be selected for the project.

2.3.1 NGCC Unit 12 (COMB19/58)

As illustrated in Figure A-6 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 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 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.

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.

These base load NGCC Units are almost entirely capable of converting the latent heat from the GT exhaust to steam in the HRSG without additional DB-firing. In their draft project equipment quotes, each vendor only presented a few situations that require operation of the DBs.

With older NGCC Unit systems or with simple cycle peaking units, the inclusion of the DBs was necessary to be evaluated/permitted because of their significant contribution of emissions at the combined stack (e.g., CO and NO_X). In contrast, for the proposed installation, each vendor is required to meet 2 parts per million by volume dry (ppmvd) at 15% O_2 emissions guarantee for CO and NO_X with or without DBs; therefore, it is unnecessary to permit the various operation modes of the DBs separately. These guarantees are further supported by each vendor's commitment to install and operate add-on control devices for CO and NO_X.

The key GT/DB equipment specifications from the equipment quotes provided by the three vendor quotes are as follows:[2]

- Maximum short-term heat input capacity up to 4,216 MMBtu/hr HHV total from both GT & DB @ -18°F.
- Maximum of 4,216 MMBtu/hr HHV from GT by itself
- Maximum of 296 MMBtu/hr HHV from DBs
- 4,157 MMBtu/hr maximum simulated heat input capacity taking into account seasonal variation for this baseload operation
- 640-664 MW (net) power output from combined cycle 1 x 1 configuration at 60 Hz
- Greater than 63% combine cycle efficiency (lower heating value [LHV])
- Air cooling for combustors instead of steam cooling
- 42-75 MW/min GT ramp up
- Startup time to full load less than 30 min for a hot start
- Provides super-heated steam greater than 600°C
- Designed for future hydrogen co-firing

[2] Please note that the heat inputs and energy generation values are subject to change depending on the final equipment selection.

The operational scenarios used to establish the maximum short-term and annual emissions are discussed in Section 3 of the application.

2.3.1.1 Air Pollution Controls

All vendors will utilize dry-low-NO_X combustors (DLN) in the GT and LNBs in the HRSG. All vendors will utilize oxidation catalysts and SCR as add-on controls to reduce stack NO_X, CO, hydrocarbons (HC), and organic HAP emissions. GHG emissions will be minimized through the use of the highly efficient combined cycle 1 x 1 GT and HRSG unit. 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.

Dry Low NO_X Combustors. The GT will feature each vendor's latest DLN combustion technology, which can reduce NO_X emissions to approximately 25 ppm, whereas the additional SCR system (described below) is designed to reduce NO_X emissions to less than 2 ppmvd at 15% O_2. The combustor also features low CO emissions at partial load, remaining compliant with permitted levels even at turndown to the MECL.

DLN combustor technology premixes air and a lean fuel mixture prior to injection into the combustion turbine that significantly reduces peak flame temperature and thermal NO_X formation. Conventional combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot spots that produce high levels of NO_X. In contrast, DLN combustors generally operate in a premixed mode where air and fuel are mixed before entering the combustor. The underlying principle is to supply the combustion zone with a completely homogenous, lean mixture of fuel and air. DLN combustor technology generally consists of hybrid combustion, combining diffusion flame (for low loads) plus DLN flame combustor technology (for high loads). Due to the flame instability limitations of the DLN combustor below approximately 50 percent of rated load, the turbine is typically operated in a conventional diffusion flame mode until the load reaches approximately 50 percent. As a result, NO_X concentrations rise when operating under low load conditions, yet the mass emissions rate at low load is less than base load.[3]

Oxidation Catalyst. The NGCC Project will install and operate an oxidation catalyst to reduce CO, HC, and organic HAP emissions produced during the combustion process in the flue gas by oxidation.

The basic chemical reactions are:

$CO + ½ O_2 \rightarrow CO_2$

$C_nH_m + (n + m/4) O_2 \rightarrow n CO_2 + (m/2) H_2O$

$C_nH_mO + (n + m/4 - 0.5) O_2 \rightarrow n CO_2 + (m/2) H_2O$

$2H_2 + O_2 \rightarrow 2H_2O$

The oxidation catalysts are formulated with precious metals (e.g., platinum group metals) and are coated on flow-through metal monoliths for minimum backpressure and compact design. Multiple catalyst formulations allow the flexibility to target specific conversion requirements, exhaust temperatures, low SO_2 to SO_3 and NO to NO_2 conversions. Oxidation catalysts can provide greater than 90% destruction of CO, VOCs, formaldehyde, and other toxic compounds.[4] See Section 5.3 of Appendix B for the methodologies used to calculate the control efficiencies used for this NGCC Project.

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[3] https://www.epa.gov/system/files/documents/2022-03/combustion-turbine-nox-technology-memo.pdf

[4] https://www.jmsec.com/fileadmin/user_upload/pdf/brochures/jmsec_gas_turbine_oxidation_catalyst.pdf

The catalytic oxidation of available SO_2 to SO_3 in the exhaust gases as it passes through the oxidation catalyst is usually 10 percent. The chosen conversion of SO_2 to SO_3 for a CO catalyst used in KU's proposed combined cycle unit is also 10 percent.[5]

SCR System. SCRs are used extensively in power generation applications including coal, oil, and combined cycle power plants. SCR is a post-combustion emission 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 (NO_X) react with oxygen and ammonia to produce nitrogen and water.

The basic chemical reactions are:

$$2\ NO + 2\ NH_3 + \tfrac{1}{2}\ O_2 \rightarrow 2\ N_2 + 3\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Small amounts of ammonia that are not consumed in the reaction result in low levels of ammonia stack emissions, known as ammonia slip. Each vendor based their emissions rates assuming no more than 5 ppmvd ammonia slip.[6]

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. Temperatures above 900°F can cause permanent damage to vanadium/titanium catalysts, thus requiring the use of high temperature zeolite catalysts and/or air tempering systems that can reduce exhaust gas temperatures prior to introduction into the catalyst. The application of SCR for the combined cycle plant is more straightforward because the SCR reactor is located downstream of the GT itself, within the tube banks at an appropriate temperature region, near the 600-700 °F range, allowing for the use of "conventional" catalysts.

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.

This process requires additional equipment to store, vaporize, dilute, and mix the reagent prior to being injected into the system through the ammonia injection grid (AIG). The dosing device supplies the vaporized ammonia into the ammonia injection blower system. It controls the quantity of the reduction agent, depending on load and NO_X values. To monitor the amount of ammonia injected, KU will install an ammonia flow meter.

Aqueous ammonia (maximum concentration of 19%) will be stored on-site in a storage tank with a capacity of approximately 35,000 gallons. The aqueous ammonia storage tank is a pressure vessel that only vents in the event of an emergency, and thus the tank will not normally vent to the atmosphere.

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[5] Page 6-4 of *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update.* EPRI, Palo Alto, CA: 2018. 3002012398

[6] Due to the installation of this advanced DLN system on these next generation GTs, ammonia slip is estimated at 5 ppmvd as opposed to 2-3 ppmvd because there will be less molecules of NO and NO_2 to react with NH_3. {See Wien et. al., *Air Emissions Terms, Definitions and General Information*, GE Energy, GER-4249 (08/05)}

The catalytic reaction of available SO_2 to SO_3 in the exhaust gases as it passes through the SCR catalyst range between 1 and 3 percent. One vendor recommended the use of a 2 percent conversion. The chosen conversion rate to SO_3 for this installation within the proposed combined cycle unit is 3 percent, which is conservative.[7]

2.3.2 Auxiliary Boiler (COMB20/59)

The NG-fired Auxiliary Boiler will be permitted with a maximum heat input capacity of 99.9 MMBtu/hr; however, the prospective equipment vendors will size to suit their design and it is expected that a smaller boiler will ultimately be installed. The combustion system will be LNB with flue gas recirculation (FGR) with a required 10:1 turndown.

The auxiliary boiler will only serve process loads and will consist of the following:

- HRSG freeze protection (only required with the unit off-line and ambient with potential freezing)
- Unit starts under warm or cold start conditions. The auxiliary boiler steam will provide sparging steam to the HRSG and condenser as well seal steam for the steam turbine. 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 8,760 hours per year to provide maximum operational flexibility.

2.3.3 Emergency Generator with Diesel-Powered Engine (COMB21/60)

The NGCC Project will employ a 2,000-kW emergency generator that will include a nominal 2,682 bhp compression ignition engine. Ultra-low sulfur diesel (ULSD) fuel with a maximum sulfur content of 0.0015 weight percent (or 15 ppm) will be used in the engine. 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.

2.3.4 Fuel Gas (Dewpoint) Heater (COMB22/61)

A NG-fired Fuel Gas (Dewpoint) Heater with a maximum heat input of 15 MMBtu/hr will be used to heat the pipeline natural gas that will be introduced to the combustion turbine and duct burners. Although this heater will not be expected to operate continuously, KU is requesting that it be permitted to allow for a continuous operation schedule up to 8,760 hours per year.

2.3.5 Emergency Diesel-Driven Fire Pump Engine (COMB23/63)

The NGCC Project will include a 400 bhp diesel-fired compression ignition engine for emergency purposes to supply energy to the fire pump engine. ULSD fuel will be used in the engine. 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.

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[7] Page 6-5 of *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update.* EPRI, Palo Alto, CA: 2018. 3002012398

2.3.6 Cooling Tower (EQPT21/62)

Steam exiting the steam turbine will be condensed via indirect heat transfer using cooling water provided a mechanical draft, eight-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.

2.3.7 Lube Oil System with Demister Vents (IA-41)

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. This process qualifies to be classified as an IA based on its low potential emissions.

2.3.8 Diesel Storage Tanks (IA-42)

All diesel consumed by the emergency use engines will be ULSD diesel. The diesel driven emergency fire pump engine will have an integrated 440-gallon dual wall tank located within the fire pump enclosure. The standby generator engine will be furnished with a base mounted dual wall tank with a capacity of 4,000 gallons. These storage tanks serving the emergency use engines qualify to be classified as an insignificant activity (IA) based on their low potential emissions.

2.3.9 HVAC Heaters (Total 10 MMBtu/hr) (IA-43)

KU plans to provision multiple natural gas-fired HVAC units within buildings that support the NGCC Project. The total combined heat input capacity of all small HVAC heaters is assumed to be 10 MMBtu/hr or less. For permitting purposes and to calculate potential emissions, the maximum combined heat input capacity is assumed.

2.4 Shutdown of Existing Operations

In conjunction with the construction of the new NGCC Project, KU will be shutting down multiple existing emission units at Brown Generating Station. Table 2-1 lists the existing emission units that will be impacted by the planned project and the proposed date of the permanent shutdown, resulting in project net emissions decreases, which are further discussed in Section 4.7.

Some existing units will remain operational (with no physical changes or changes to their method of operation) after the construction of the NGCC Project. The construction of the new NGCC Unit will have no impact on the utilization, method of operation, or emissions from these existing units. The existing emission units that fall into one of these categories include:

- Simple cycle GTs (#5 through #11)
- Emergency use internal combustion engines
- NG-fired process heaters
- Gasoline dispensing and storage tank(s)
- Diesel dispensing and storage tank(s)
- Miscellaneous organic liquids tanks
- Landfill wind erosion fugitives
- Paved and unpaved roads

Emissions from these existing emission units are not discussed in Section 3 because these units will be unaffected (physically or operationally) by the proposed project.

Table 2-1. List of EUs to be Shutdown with NGCC Project at Brown Generating Station

Title V Permit ID#	KyEIS Process ID#	Emission Unit Description	KyEIS Process Description	Control Description	Project Impacts
03	1	Unit 3 5300 MMBtu/hr Indirect Heat Exchanger	Fuel: Coal	Unit 3 Low NOX Burners	Shutdown (4/1/2028)
03	1			Unit 3 SCR	||
03	1			Unit 3 PJFF	||
03	1			FGD for Unit 3	||
03	2		Fuel: #2 Fuel Oil	None	||
07	1	Coal Handling Operations 07	West Track Hopper	Enclosures	Shutdown (4/1/2028)
07	2		Conveyor A-1	Enclosures	||
07	3		Conveyor E	Enclosures	||
07	4		Conveyor F	Enclosures	||
07	5		Conveyor G	Enclosures	||
07	6		Conveyor H	Enclosures	||
09	1	Coal Handling Operations 09	East Track Hopper	Enclosures	Shutdown (4/1/2028)
	2		Conveyor A	Enclosures	||
	3		Conveyor B	Enclosures	||
	4		Conveyor C	Enclosures	||
	5		Conveyor J	Enclosures	||
	6		Coal Stockpile	Enclosures	||
13	1	Coal Handling Operations 13	Conveyor D [Tripper for Units 1 & 2]	High Efficiency Cyclone	Shutdown (4/1/2028)
	2		Conveyor K-1 [Upper Tripper for Unit 3]	Baghouse, Partial Enclosure	||
	3		Conveyor K [Lower Tripper for Unit 3]	Baghouse, Partial Enclosure	||
16	1	Coal Crushing	Four Crushers and Crusher House	Enclosure/Wet Scrubber	Shutdown (4/1/2028)
30-31	1	Limestone Unloading	Limestone Truck Dump Station #1	Fabric Filter	Shutdown (4/1/2028)
	2	Limestone Unloading	Limestone Truck Dump Station #2	Fabric Filter	||
32-34	1	Limestone Handling	Limestone Stacking Tube	Fabric Filter	Shutdown (4/1/2028)
	2	Limestone Handling	Limestone Reclaim Conveyor #1 & 2	Fabric Filter	||
36-38	3	Cooling Tower	Unit 3 Cooling Tower with Drift Eliminators		Shutdown (4/1/2028)
50	1	CCR Landfill Operations and Haul Trucks	Paved Empty Bottom Ash Trans	Dust Suppression	Shutdown (4/1/2028)
	2		Paved Full Fly Ash Transport	Dust Suppression	||
	3		Paved Empty Gypsum Transport	Dust Suppression	||

Title V Permit ID#	KyEIS Process ID#	Emission Unit Description	KyEIS Process Description	Control Description	Project Impacts
	4		Paved Full Bottom Ash Transport	Dust Suppression	||
	5		Paved Empty Fly Ash Transport	Dust Suppression	||
	6		Paved Full Gypsum Transport	Dust Suppression	||
	7		Unpaved Empty Bottom Ash Trans	Dust Suppression	||
	8		Unpaved Full Bottom Ash Trans	Dust Suppression	||
	9		Unpaved Empty Fly Ash Trans	Dust Suppression	||
	10		Unpaved Full Fly Ash Trans	Dust Suppression	||
	11		Unpaved Empty Gypsum Trans	Dust Suppression	||
	12		Unpaved Full Gypsum Trans	Dust Suppression	||
	13		Travel Heavy Equip. Landfill	Dust Suppression	||
IA-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)		Shutdown (4/1/2028)
IA-3		Turbine oil tanks for Unit 3 (2 @ 9,000 gallons each)	T-17 & T-18 (Steam Plant/Unit 3 Clean/Dirty Turbine Oil)		Shutdown (4/1/2028)
IA-7		Burning of Off-Specification Used Oil for Energy Recovery			Shutdown (4/1/2028)
IA-9		Distillate Oil and/or Propane Coal Belt Heaters			Shutdown (4/1/2028)
IA-10		Limestone Storage Pile			Shutdown (4/1/2028)
IA-11		Limestone Reclaim Maintenance Tunnel Exhaust Vent			Shutdown (4/1/2028)
IA-12		Sorbent Storage Silos (for SO3 mitigation)			Shutdown (4/1/2028)
IA-16		Liquid Hg Control Additives			Shutdown (4/1/2028)
IA-20		Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons)	R4, R44		Shutdown (4/1/2028)
IA-21		Turbine oil reservoir for Unit 3 seal oil (150 gallons)	R14		Shutdown (4/1/2028)
IA-25		PAC Storage Silos			Shutdown (4/1/2028)
IA-26		Bottom Ash Transport			Shutdown (4/1/2028)
IA-27		Fly Ash Transport			Shutdown (4/1/2028)
IA-28		Gypsum Transport & Process Water System Solids			Shutdown (4/1/2028)

Title V Permit ID#	KyEIS Process ID#	Emission Unit Description	KyEIS Process Description	Control Description	Project Impacts
IA-29		Landfill Truck Loading and Unloading & Process Water System Solids			Shutdown (4/1/2028)
IA-30		Active Area of the CCR Landfill & Process Water System Solids (Wind Erosion)			Shutdown (4/1/2028)
IA-31		Slipstream Carbon Dioxide (CO2) capture System – Research			Shutdown (4/1/2028)
IA-32		Bottom Ash Handling including storage pile (associated with CCR landfill operations)			Shutdown (4/1/2028)
IA-33		Fly Ash Handling including load out to trucks (associated with CCR landfill operations)			Shutdown (4/1/2028)
IA-34		Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)			Shutdown (4/1/2028)
IA-35		Fly Ash Storage Silos (2) (associated with CCR landfill operations)			Shutdown (4/1/2028)
IA-36		Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)			Shutdown (4/1/2028)

3. EMISSIONS CALCULATION METHODOLOGIES AND SUMMARY

This section summarizes the emission calculation methodologies for the emission sources that comprise the proposed NGCC 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 GT, the mode of operation. The NGCC Project's annual potential emissions for regulated NSR pollutants and HAPs are summarized in Table 3-2. These potential emissions are used as the basis for determining applicability of the project with respect to applicable regulatory requirements, which is discussed subsequently in Sections 4 and 5.

A more detailed set of documented emission calculations is presented in Appendix B of the application for all the new emission units that are part of the NGCC Project, which are listed below. The nomenclature for the emission unit and emission point IDs shown below are placeholders based on the next sequential numbers in the facility's current emission unit inventory and can be finalized by the Division upon its review of the application.

EU ID[8]	Description
• COMB19/58	Unit 12 Gas Turbine with HRSG/Duct Burners
• COMB20/59	Auxiliary Steam Boiler
• COMB21/60	2 MW Diesel Emergency Generator Engine
• COMB22/61	Fuel Gas (Dewpoint) Heater
• COMB23/63	400 HP Emergency Diesel Driven Fire Pump Engine
• EQPT21/62	Mechanical Draft Cooling Tower (8 Cells)
• IA-41	Lube Oil System with Demister Vents
• IA-42	4,000- and 440-Gallon Diesel Storage Tanks
• IA-43	HVAC Heaters (Total 10 MMBtu/hr)

3.1 Unit 12 Gas Turbine with HRSG (COMB19/58)

The primary emissions units for the NGCC Project are the NG-fired GT and HRSG, which includes DBs. 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 GT/DB 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 hours per year with or without duct firing.

Heat input to a gas turbine varies as a function of the fuel (type, composition, and quality), ambient temperature, relative humidity, EC operation, and DB operation. Maximum heat input and maximum emissions rates typically occur at 100 percent load and the minimum design ambient temperature (i.e., -18°F). As explained in more detail in Section 4 of Appendix B, while the GT/DB can achieve a

[8] The proposed EU ID shown is a concatenation of the expected KyEIS Equipment ID and the KyEIS Source ID. Customarily, the KyEIS Source ID is used as the identifier for emission units in the Title V permit. The units with an "IA" number are expected to be designated as insignificant activities to be included in Section C of the Title V permit.

maximum heat input capacity of 4,216 MMBtu/hr (for Vendor A Case 1 for GT only at -18°F and 100% of baseload), the potential emissions calculation used 4,157 MMBtu/hr (or 3.925 MMscf/hr) as the maximum simulated heat input capacity.

KU's proposed baseload NGCC Unit is almost entirely capable of converting the latent heat from the GT exhaust to steam in the HRSG without additional DB firing. In their equipment quotes, each prospective vendor only presented a few situations that require operation of the DBs, such as periods of time in the summer months to provide supplemental heat input capacity with the goal of ensuring the same MW generation as the average ambient case. The maximum heat input capacity from all three vendors was 296 MMBtu/hr (HHV) for the DB.

3.1.1.1 NO_X, CO, VOC, and PM Emissions

Similar to the heat input capacity, emissions from a gas turbine are also a function of the fuel (type, composition, and quality), ambient temperature, relative humidity, EC operation, and DB operation, but they additionally are affected by inherent controls, add-on controls, chemical conversions, and other miscellaneous factors. As documented in Sections 4 and 5 in Appendix B, maximum hourly controlled and uncontrolled emissions of NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, ammonia (NH_3), and formaldehyde for the proposed gas turbine rely on the vendor operational data and KU's vendor guarantee requirements for the NGCC Unit, which are listed in Table 3-1. Emissions factors for these pollutants were calculated as the maximum hourly emissions rate divided by 4,157 MMBtu/hr (equivalent to 3.925 MMscf/hr of NG combustion). Annual controlled emissions of NO_X, CO, and VOC used these same maximum simulated heat input capacities times the emissions factor times 8,760 hr/yr.

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

Pollutant	Emissions Basis
NO_X	2 ppmvd @ 15% O_2
CO	2 ppmvd @ 15% O_2
VOC	1-2 ppmvd @ 15% O_2
$PM_{10}/PM_{2.5}$	8-23.3 lb/hr
Formaldehyde	0.091 ppmvd @ 15% O_2
NH_3 slip	5 ppmvd @ 15% O_2

Source: Maximum of Vendor A, B, or C

The gas turbine unit will continue to comply with the presented emission rates irrespective of ambient weather conditions at all loads above MECL. Any emissions resulting from SU/SD operations are described in Section 3.1.2. Information regarding inherent and add-on controls used in the GT/HRSG system were previously explained in Section 2.3.1.

For NO_X, a nominal control efficiency (CE) of 90% for the SCR was selected for purposes of defining a conservatively (high) uncontrolled emission factor. This CE is not constant and not an equipment guarantee as it will normally range between 75% and 91% depending on available nitrogen content and GT combustor design/operation. For CO and VOC (and other organic HAPs), a nominal CE of 90% and 50%, respectively, for an oxidation catalyst was selected for purposes of defining the uncontrolled emission factors.

3.1.1.2 SO_2 and H_2SO_4 Emissions

Annual emissions of SO_2 and H_2SO_4 mist were based on a maximum pipeline NG sulfur content and additional factors to account for chemical conversions. For SO_2, all vendors used an expected maximum sulfur content for the pipeline gas of 0.5 grains (gr)/100 standard cubic feet (Cscf). In actuality, based on actual measurements of the pipeline gas consumed by Brown Generating Station, the highest sulfur measured in the last 5 years was only 0.116 gr/Cscf. The SO_2 emissions are nonetheless based on a sulfur content of 0.5 gr/Cscf 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.

The conversion of SO_3 to H_2SO_4 mist and condensable PM (sulfates and nitrates) is influenced by the sulfur content in the pipeline NG, ambient temperature, relative humidity, EC operation, DB operation, oxidation over the CO catalyst, oxidation within the SCR, available moisture, ammonia slip concentration, acid dew point, and other factors. The hourly conversion used in the potential emissions calculations for permitting purposes conservatively assumes a 10% conversion in the GT/DB plus 3% conversion from the SCR plus 10% from CO catalyst (i.e., 23% total), consistent with the approach of the following citation, "*Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update*. EPRI, Palo Alto, CA: 2018. 3002012398, Pages 6-4 & 6-5", where the total conversion to H_2SO_4 mist assumes 10% conversion for GT/DB + 3% for SCR + 10% for CO catalyst.

3.1.1.3 Formaldehyde and HAP Emissions

Controlled formaldehyde emissions are calculated based on an emissions guarantee of 91 parts per billion by volume, dry (ppbvd) @15% O_2, which is also equivalent to the applicable standard in NESHAP Subpart YYYY, 40 CFR §63.6100. This concentration was then converted to a pound per MMBtu emissions factor based on Reference Method (RM) Method 19 determination of the dry F factor (Fd) used for natural gas combustion. KU chose to use Vendor A's derived Fd at ~8638 dscf/MMBtu, which was derived from RM 19 equations 19-13 through 19.15. The uncontrolled emissions factor for formaldehyde was obtained from Table 3.1-3 of the U.S. EPA's AP-42 Chapter 3, Section 3.1 *Stationary Gas Turbines*.[9] As a result, the estimated control efficiency for formaldehyde is 68%.

The GT's uncontrolled emission factors for HAPs other than acetaldehyde were also based on Table 3.1-3 of AP-42 as well. The background document supporting this chapter provided controlled emissions factors when using a CO catalyst for acetaldehyde, acrolein, and benzene.[10] See Section 5.3.3 of Appendix B for additional details and for the derivation of control efficiencies.

Even though the DB will be used sparingly over the summer months and because there is no restriction on its use, KU also provides the standard uncontrolled emissions factors obtained from Tables 1.4-2, 1.4-3, and 1.4-4 of the U.S. EPA's AP-42 Chapter 1, Section 1.4 *Natural Gas Combustion*.[11] A 50 percent control efficiency from the oxidation catalyst was applied to calculate the controlled emission factors for the organic HAPs. See Section 5.3.4 of Appendix B for additional details.

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

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

[11] https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

For pollutants where there was overlap between the Sections 1.4 and 3.1 of AP-42, the highest emissions factor was used to derive the potential emissions from the GT/DB system. As shown in Section 3 of Appendix B, using the DB's uncontrolled emission factor for hexane at 1.8 lb/MMscf to estimate the GT/DB's annual emissions results in an annual potential to emit of 15.56 tons per year (tpy) compared with the next highest HAP at 3.95 tpy for formaldehyde, which is an expected pollutant from this type of installation.

3.1.1.4 GHG Emissions

GHG emissions are estimated based on proposed equipment specifications as provided by the prospective vendors and the default emission factors in the U.S. EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas). 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 the gas's associated global warming potential (GWP), which are specified in Table A-1 to Subpart A of 40 CFR Part 98.

3.1.2 GT/DB Emissions from Startup and Shutdown Operations

For the proposed NGCC Unit, startup will be defined as the period between the commencement of ignition and when the combined-cycle unit reaches emissions compliance (i.e., 2.0 ppmvd CO and NO_X at 15% O_2 at the stack).

The NGCC Unit equipment package from each of the prospective vendors each has its own unique features that allow each NGCC Unit to quickly achieve emissions compliance during a cold, warm, or hot start event. The following provides the underlying basis for each vendor's pound per event emission estimates.

- Cold starts (CS) are preceded by over 72 hours of shutdown.
  - Expected maximum annual CS events = 5 events/yr over a 40 to 70 minutes ramp up time

- Warm start (WS) or "non-cold startup" are preceded by a shutdown between 8 and 72 hours. A value of 48 hours is used.
  - Expected maximum annual WS events = 45 events/yr over a 30 to 60 minutes ramp up time

- Hot starts (HS) are defined as taking place within 8 hours of the previous shutdown.
  - Expected maximum annual HS events =100 events/yr over a 21 to 35 minutes ramp up time

- Shutdowns (SD) occur for 12-21 min and the total number of these events is the sum of all cold, warm, and hot SUs.
  - Expected maximum annual SD events = 150 events/yr over 12 to 21 minutes until emissions cease

These assumptions were provided by each vendor, and they are neither guaranteed, nor are they intended to be included in the permit as emissions limits or operational restrictions. While the SU/SD assumptions provide valuable information, from an air permitting perspective, it is more important to focus on the total mass of emissions per event.

NO_X, VOC, CO, and PM emissions vary during SU/SD events; 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, VOC, CO, and PM are separately defined for SU/SD events. The total emissions for each event are provided in Sections 4.1 through 4.3 in Appendix B. As shown in Section 5.5.1 of Appendix B, the emissions factors in pounds per event for the regulated NSR pollutants are based on the highest vendor-provided lb/event. As an example, as documented there, using these methodologies, the total emissions from NO_X estimated for 150 SU/SD events in a year adds an additional 19.5 tpy to the NGCC Project potential emissions.

This methodology of using the maximum of each vendor's individual CS, WS, HS, and SD event emissions value for each pollutant adds an additional level of conservativeness.

3.1.3 GT/DB Annual Emissions

Tables in Sections 4.1 to 4.3 in Appendix B, provide maximum hourly pollutant emissions rates for the GT/HRSG unit based on three different loads and three different ambient temperatures, including EC and DB operation. Also provided are the outliers with the highest emissions rate. In all cases, the partial loads resulted in lower hourly emissions rates. A summary of the cases provided by each vendor that were evaluated for defining potential emissions is as follows.

- Vendor A
  - GT loads at 30%, 32.3%, 33.3%, 36.1%, 41.5%, 63.9%, 74.3%, 75%, and 100%
  - Inlet air temperatures of -18, 15, 45, 57, 90, and 106°F
  - Relative humidity (RH) of 40, 50, 55, 60, and 70
  - Ambient pressure of 14.257 pounds per square inch absolute (psia)
  - Evaporative Cooler (EC) on at 90-106°F and 40-50% RH
  - DB on at 90-106°F and 40-50% RH
  - 1 x 1 Combined Cycle Operation Only
  - No ability to by-pass controls

- Vendor B
  - GT loads at 100%
  - Inlet air temperatures of -18, 15, 45, 57, 59, 90, and 106°F
  - Ambient pressure of 14.245 psia
  - EC on at 59-106°F and 40-60% RH
  - DB on at 90°F and 50% RH
  - 1 x 1 Combined Cycle Operation Only
  - No ability to by-pass controls

- Vendor C
  - GT loads at 35%, 75%, and 100%
  - Inlet air temperatures of -18, 15, 45, 57, 90, and 106°F
  - Ambient pressure of 14.225 psia
  - EC on at 90-106°F and 40-50% RH
  - DB on at 90°F and 50% RH
  - 1 x 1 Combined Cycle Operation Only
  - No ability to by-pass controls

Given the range and breadth of the cases presented, there are numerous ways to derive the annual potential emissions for the GT. As shown in Section 4.4 of Appendix B, four different simulated annual operating profiles were evaluated for defining potential emissions:

- Profile 1 calculates the annual emissions using 8,760 hours at the highest hourly emissions rate at the average ambient temperature. In every case, DBs will not be necessary to generate the rated output.

- Profile 2A calculates the annual emissions with 2,000 hr/yr of operation at 15°F, 4,760 hr/yr at 57°F, and 2,000 hr/yr at 90°F. The DBs and EC only kick in during the summer months. Although it artificially elevates the potential emission rate, for simplicity and conservatism, the total hours do not subtract periods of non-operation between a shutdown and a startup, nor do the total hours exclude the total time of GT operation during the events.
- Profile 2B is the same as 2A except 127 hours of time for SU/SD events is subtracted. Again, this case does not subtract periods of non-operation between a shutdown and a startup.[12]
- Profile 3 is the maximum hourly emissions rate for any case multiplied by 8,760 hr/yr.

As shown in Sections 4.5 and 4.6 of Appendix B, in reviewing the calculated annual emissions for the worst-case operating profiles, KU has chosen to represent the potential emissions for the GT/DB based on Profile 2A. Profile 3 is not used because it is not practically realistic and could never occur in practice. While Profile 2A is also extremely conservative, in that it does not subtract for SU/SD hours (which is done in Profile 2B), the differences are not significant. Profile 2A, which considers the differences for cold and hot seasons, also predicts slightly higher potential emissions than the baseload case at the average ambient temperature. Thus, it is conservative but reasonable to use annual emissions for Profile 2A to define the potential to emit (PTE).

Based on the defined PTE values (tpy), the equivalent hourly average emission rates (lb/hr) for each pollutant can be calculated. An emission factor in terms of lb/MMBtu can then be calculated based on the vendor-provided heat input associated with the case for which the PTE value is derived. See Section 4.4 of Appendix B, which provides the underlying heat input rate.

For example, steady-state stack exhaust emissions and the emissions factor of NO_X are calculated as follows.

Profile 2A NO_X (lb/hr) = 136.8 tpy × 2,000 lb/ton / 8,760 hr/yr = 31.23 lb/hr for Vendor B (at 3,850 MMBtu/hr and 3,656 MMscf/hr)
NO_X Emission Factor (lb/MMBtu) = 31.23 lb/hr / 3,850 MMBtu/hr = 0.00811 lb/MMBtu
NO_X Emission Factor (lb/MMscf) = 31.23 lb/hr / 3.656 MMscf/hr = **8.541 lb/MMscf**

Yet, Maximum Natural Gas Fuel Consumption is for Vendor A = 4,157 MMBtu/hr (maximum for any pollutant) / 1,053 MMBtu/MMscf = 3.948 MMscf/hr
NO_X (lb/hr) = **8.541 lb/MMscf** × 3.948 MMscf/hr = 33.71 lb/hr

Regarding the SU/SD events, each vendor provided NO_X, CO, VOC, and $PM/PM_{10}/PM_{2.5}$ emissions over each event based on the anticipated maximum number of events that might happen over 12 months. As explained above, using the average of the range for all three vendors, these events would span a total of 127 hours per year. And, if the time in between these events was accounted for in the calculations, the GT/DB would not be operating (or emitting) for 3,447 hr/yr (i.e., 5 cold SU x 72 average hours down + 45 warm SU x 48 average hours down + 100 hot SU x 8 average hours down). Thus, basing the potential emissions on 8,760 hr/yr of operation and then additionally adding the emissions from the SU/SD events yields a conservatively high emission rate. However, this approach is done specifically to avoid the need to establish enforceable individual operating limits around the frequency or duration of SU/SD events in the permit.

[12] 127 SU/SD hrs = (5 cold SU events × average of 40 & 70 min cold SU + 45 warm SU events × average of 30 & 60 min warm SU + 100 hot SU events × average of 21 & 35 min hot SU + 150 SD events × average of 12 & 21 min SD) × 60 min/hr

Annual potential emissions based on the methodologies described for both the GT/DB and SU/SD events are shown in Section 5.7 in Appendix B.

3.2 Ancillary Equipment

There are several emissions units that are part of the NGCC Project and 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 (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61)

Potential emissions from the Auxiliary Boiler and Fuel Gas (Dewpoint) Heater are estimated based on KU's vendor requirements, pipeline natural gas specifications, and published AP-42 emissions factors. Annual potential emissions for the Auxiliary Boiler and the Fuel Gas (Dewpoint)Heater are documented in Sections 6.3 and 7.3 of Appendix B, respectively.

3.2.2 Emergency Use Diesel-Fired Engines

The emergency diesel-fired fire water pump engine (COMB23/63) and the emergency diesel-fired engine for the planned emergency generator engine (COMB21/60) 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 certified emissions data from a representative manufacturer (CAT for the emergency generator and John Deere for the emergency fire water 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 10.3 and annual potential emissions for the emergency fire water pump engine are shown in Section 11.3 in Appendix B.

3.2.3 Storage Tanks and Organic Losses

A 4,000-gallon, dual walled, above ground, ULSD fuel storage tank will be located in the base of the emergency generator engine. In addition, a 440-gallon, fire-rated, above ground, ULSD fuel storage tank will be used for the emergency fire water pump engine. The two ULSD fuel storage tanks are considered sources of VOC emissions.

Standing and working losses of VOCs were calculated for both diesel 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*.[13] Annual potential VOC emissions from the 4,000-gallon and 440-gallon diesel tanks are estimated to be 1.98 and 0.27 lb/yr, respectively (see Section 13.2 in Appendix B).

Another 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 CT 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

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

the CT 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 emissions. Annual potential VOC emissions from the lube oil demister vents are shown in Section 12.2 of Appendix B.

3.3 Potential Emissions Summary

A summary of the calculated potential emissions for the NGCC Project is provided in Table 3-2. Detailed emission calculations including emission factors and references are provided in Appendix B of the permit application report.

Table 3-2. NGCC Project – Total Potential Emissions from New Emission Units

Pollutant	Potential to Emit (tpy)
PM	104.0
PM_{10}	103.0
$PM_{2.5}$	102.0
NO_X	199.9
CO	161.4
VOC	51.6
SO_2	25.4
H_2SO_4	8.8
Lead	0.0089
CO_2e	2,214,260
Hexane (HAP)	16.5
Formaldehyde (HAP)	4.0
Total HAPs	26.1
NH_3	122.8

4. NSR APPLICABILITY ASSESSMENT

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

4.1 PSD/NA-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 (NA-NSR) 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 Generating 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.[14] 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 State Implementation Plan (SIP) at 401 KAR 51:017.[15]

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 NSR pollutants*.[16] The regulated NSR pollutants of relevance to the Brown Generating Station and the NGCC Project are NO_X, CO, SO_2, PM, PM_{10}, $PM_{2.5}$, 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

[14] 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

[15] 40 CFR 51.166(a)(1)

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

subject to regulation to be treated as a regulated NSR pollutant that can fall under the PSD requirements.[17] 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.[18]

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.[19,20] Existing operations at Brown Generating 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 Generating Station is classified as an existing major stationary source under the PSD program.

4.3 NSR Applicability Analysis Methodology

4.3.1 Defining the Project

The proposed NGCC Project involves the new installation and operation of the new NGCC system emission units in conjunction with shutting down the Unit 3 boiler and its material storage, handling, and processing. No other emission units will have any emissions increases or decreases caused by the NGCC Project. The existing electric generation and transmission assets supporting Unit 3 will remain in place; however, certain modifications/enhancements will be made to accommodate the NGCC Unit.

Since the new Unit 12 Gas Turbine with HRSG and its auxiliary support operations will be under the same common control and ownership, have the same SIC code, and be constructed and operated within the same property boundary, construction of NGCC Project is a modification to an existing major stationary source.[21]

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 a proposed project is considered a new or existing emission units.

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[17] *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).

[18] 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.

[19] 401 KAR 51:001, Section 1(118)

[20] 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.

[21] *Modification* is defined in 401 KAR 51:001, Section 1(136).

401 KAR 51:001, Section 1(64) defines emission units as any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant and includes an electric utility steam generating unit. 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.*

The GT/DB, Auxiliary Boiler, Fuel Gas (Dewpoint) Heater, Cooling Tower, Emergency Engines, HVAC Units, Storage Tanks, and Demister Vents that are proposed with the NGCC Project are all considered new emissions units.

Unit 3 coal-fired boiler, which will shut down as part of the NGCC Project, along with its material handling, storage, and transfer operations, which will correspondingly shut down, qualify as existing units since they have been in operation for more than two years.

4.3.3 Two-Step Major Modification Determination Process

As Brown Generating 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 proposed 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 a *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[22] *or actual-to-potential; for new units, calculated by actual-to-potential]*[23, 24]

(ii) Any 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…

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.

Historically, Step 1 emissions would not have accounted for proposed equipment shutdowns planned as part of a project, requiring instead that such emission decreases be accounted for as part of the Step 2 analysis, along with any additional contemporaneous increases and decreases. However, in 2020, EPA promulgated the "Project Emissions Accounting" clarification, establishing that the Step 1 emissions can include decreases "provided they are part of a single project" and affirmed that a project can include a combination of new and existing units (i.e., hybrid).[25]

It is KU's understanding that the Division has yet to formally accept the EPA promulgated the "Project Emissions Accounting" clarification into the agency's procedures. Although the result is the same either way, consistent with the Division's currently stance, the emissions decreases from Unit 3's coal-fired operations at Brown Generating Station have been excluded in Step 1. Instead, KU only evaluated the project emissions increase for the proposed project (i.e., Step 1) using the methodologies outlined in the following sections. An evaluation of the net emissions increase (i.e., Step 2) provides the opportunity to count the emission decreases from the equipment being shutdown with the project as described below.

4.4 Components of Project Emission Increases

To calculate the project emissions increase, the difference between a future emission level (either potential emissions or projected-actual-emissions) and the baseline actual emissions must each be calculated. These components of the emission increase calculation formula are defined in the following sections.

[22] 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 …

[23] 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 …

[24] 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 …*

[25] Federal Register Volume 85, No. 227, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting,* Final Rule, pp. 74890-74909, published November 24, 2020. Quotation per p. 74893.

4.4.1 Potential Emissions

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.

4.4.2 Baseline Actual Emissions (BAE)

For existing emission units being modified or affected, to determine the emission increases associated with the proposed project, baseline actual emissions are first defined. *Baseline Actual Emissions* (BAE) are defined 401 KAR 52:001, Section 1(20):

> *For an existing electric utility steam generating unit (EUSGU), baseline actual emissions means the average rate, in tons per year, the unit actually emitted during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date the owner or operator begins actual construction of the project, unless a different 24-month time period is more representative of normal source operation…*

For new emission units covered in the project scope, the BAE are set to zero. For an *emission unit* that "has existed for less than two (2) years from the date the unit first operated",[26] the baseline emissions levels are set equal to "the unit's potential to emit."[27]

The baseline period can be selected on a pollutant-by-pollutant basis, but for a given pollutant, only one baseline period can be used across all new, modified, and associated emission units in the project scope. The baseline period selection process typically involves a review of historical production and emissions data over the previous 5 years at an existing electric utility steam generating unit to identify a historically representative period of 24-month rolling average production/annual emissions.

Since commercial operation for the Brown Generating Station NGCC Project is targeted for April 1, 2028, and 37 months are allocated for construction and commissioning, the presumed start of on-site construction is **March 1, 2025**. The 5-year period immediately preceding this date begins on March 1, 2020. Thus, for the NGCC Project the earliest baseline period available to select for each pollutant is the 24-month period ending February 2022 (i.e., March 2020 to February 2022).

The selected baseline period for each pollutant used along with documentation of the BAE (and thus the equivalent emission reductions for the project) are provided in Appendix B in Section 14 for Unit 3 Boiler, Section 15 for Coal Handling Operation, Section 16 for Limestone Handling Operations, Section 17 for Unit 3 Cooling Tower, and Section 18 for CCR Landfill Operations.

4.4.3 Projected Actual Emissions (PAE)

Projected Actual Emissions (PAE) are defined by 401 KAR 51:001, Section 1(199):

> *"Projected actual emissions" means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or*

[26] *Emission Unit* definition in 401 KAR 51:001 Section 1(64)(a).

[27] 401 KAR 51:001 Section 1(20)(c).

> *its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.*

For units in which the proposed projects would not change the potential to emit or the design capacity, an applicant sets the PAE for the following five years after authorization of the proposed project(s).

In determining PAE, following 401 KAR 51:001, Section 1(199)(b)1.a., the source:

> *Considers all relevant information, including historical operational data and the company's own representations of expected and highest projected business activity, filings with the cabinet and the U.S. EPA, and compliance plans under the Kentucky SIP...*

For unmodified, associated units, future emissions are calculated by the same actual-to-projected actual procedure as other existing emissions units.

4.4.4 Additional Associated Emission Unit Increases

In addition to the emission increases from new or modified units, emission increases from associated emission units that may realize an increase in emissions due to a project must be included in the assessment of the project emissions increases.

4.5 Project Emission Increase Evaluation

As stated above, the NGCC Project will constitute a modification to an existing major stationary source and involves new emissions units and existing emissions units. The procedure for calculating (before beginning actual construction) 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)3,

> *(3)* **Hybrid test for projects that involve multiple types of emissions units.** A significant emissions increase of a regulated NSR pollutant shall be projected to occur if the sum of the emissions increases for each emissions unit, using a method specified in subparagraphs 1 and 2 of this paragraph as applicable for each emissions unit, equals or exceeds the significant amount for that pollutant.

Subparagraph (1) of 401 KAR 51:017, Section 1(4)(a) references the **actual-to-projected-actual applicability test** for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the PAE and the BAE for each existing emissions unit, equals or exceeds the significant amount for that pollutant.

Subparagraph (2) of 401 KAR 51:017, Section 1(4)(a) references the **actual-to-potential test** for projects that only involve construction of a new emissions unit(s).

Therefore, for hybrid projects that involve existing and new emission units, such is the case with the NGCC Project, an actual-to-projected actual applicability test is used for the existing units and an actual-to-potential test is used for the new units. The sum of emission increases from these tests for all affected units associated with the project is the total PEI assessed against the significance thresholds in Step 1.

> PEI = Sum of New EUs (PTE) + Sum of differences of Existing EUs (PAE_j – BAE_j) + Sum of differences of Unmodified EUs (PAE_k – BAE_k)

For a new emissions unit, PAE_i = PTE, and BAE is set to 0.0 tpy. For example, as shown in Section 2 of Appendix B, the "sum of the differences" for NO_X emissions from the GT/DB, a new emission unit, are as follow:

PAE_{Unit12} = PTE_{Unit12} = 167.2 tpy
BAE_{Unit12} = 0 tpy
PEI_{Unit12} = 167.2 tpy PAE – 0 tpy BAE = 167.2 tpy for NO_X

For modified emissions units, PAE_i is the forecast of each emission unit's future actual emissions.[28] As part of the NGCC Project, there will be existing emissions units that are shut down or modified because of the project. For example, PAE_{Unit3} will have 0.0 tpy of NO_X as the projected actuals because it is being shut down in conjunction with the NGCC Unit addition. Moreover, each one of these modified emissions units (e.g., Unit 3) have an established BAE as documented in Sections 14 through 18 of Appendix B.

For example, the "sum of the differences" for NO_X emissions from the existing Unit 3 coal-fired boiler are as follow:

PAE_{Unit3} = 0.0 tpy
BAE_{Unit3} = 291.8 tpy is the 2-year average actual emissions in the baseline period (July 2020 through June 2022)
PEI_{Unit3} = 0.0 tpy PAE – 291.8 tpy BAE = -291.8 tpy for NO_X

In cases like this where the difference between the PAE and BAE for a modified existing emission unit represents an emissions decrease, as shown above, the future emissions must be recalculated on a potential basis if this emissions reduction is intended to be included in the contemporaneous netting calculations,[29] unless the operative PSD program has been updated to include EPA's recent project emissions accounting rulemaking.[30] Since Kentucky has not yet adopted EPA's recent project emissions accounting rulemaking, emissions decreases from modified emission units are treated as contemporaneous changes subject to the provisions of 401 KAR 51:001 Section 1(144)(a)2 regardless of whether they occur as part of the project or as a separate contemporaneous event. In other words, the only step of the PSD applicability assessment that is relevant for an emissions reduction caused by a proposed project is the Step 2 contemporaneous netting analysis.

Unmodified existing emission units located upstream or downstream of new or modified emissions units in the project scope are addressed in the calculation of an emissions increase for the project if these unmodified units will experience a change in actual annual throughput/utilization due to the operation of the proposed new/modified units. This type of upstream/downstream emission unit is commonly referred to as an "associated" emission unit. There will be no changes to the MW generation, heat input capacities, or

[28] In a letter from Scott Pruitt, EPA Administrator to EPA Regional Administrators (December 7,2017), when a source performs a pre-project NSR applicability analysis in accordance with the procedure in the regulations, and follow the applicable recordkeeping and notification requirements, the source has met the pre-project source obligations. Unless there is clear error (e.g., source applies an incorrect SER), the projected actual emissions are not second-guessed. (https://www.epa.gov/sites/default/files/2017-12/documents/nsr_policy_memo.12.7.17.pdf)

[29] Letter from Ms. Cheryl Newton, EPA Region 5 Director of Air and Radiation Division to Mr. Keith Baugues, Assistant Commissioner Indiana Department of Environmental Management dated April 4, 2011 (http://www.epa.gov/region7/air/nsr/nsrmemos/atpanet.pdf)

[30] 85 FR 74890, *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting – Final Rule*, November 24, 2020.

natural gas/fuel oil combustion rates from the simple cycle GTs and thus they will not have any associated emissions changes as part of the NGCC Project.

As shown in Section 2 of Appendix B and summarized below, Step 1 emissions increases are significant for all regulated NSR pollutants except for lead; therefore, KU proceeded to the contemporaneous netting 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. The purpose of the netting analysis is to determine if, after accounting for the creditable emission increases and decreases for a particular pollutant in the contemporaneous period, the net project emissions increase is still above the significant emission rate (SER) for that pollutant. When any emissions decrease is claimed (including those associated with the proposed project), all source-wide creditable and contemporaneous emissions increases and decreases of the pollutants subject to netting must be included in the PSD applicability determination.

A contemporaneous emissions change is creditable if it meets all of the following criteria:

- ► The Division or the EPA has not relied on the change in issuing a PSD permit for the source that is still in effect when the increase in actual emissions from the particular change occurs.
  - A reviewing authority only relies on an increase or decrease when, after taking the increase or decrease into account, it concludes that a proposed project would not cause or contribute to a violation of an increment or ambient standard. In other words, an emissions change at an emission unit which was considered in the issuance of a PSD permit for the source is not available to be used in subsequent netting calculations.

- ► An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.
  - Pursuant to 401 KAR 51:001, Section 1(144)(a)(2), the old level of emissions for calculating increases and decreases in a netting analysis is defined using the same "baseline actual emissions" term [401 KAR 51:001, Section 1(20)] relevant to the Step 1 emissions increase calculations and described in Section 4.3. However, the contemporaneous emissions change calculations are not required to use the same baseline period selected for the project for the Step 1 emissions increase calculations. The 5-year look-back period for setting the baseline period of a contemporaneous project is established by the date of the contemporaneous emissions change and not the start of construction date for the new/modified sources in the proposed project scope.
  - For determining an emissions increase of an existing emission unit, the new level of emissions is the lower of the unit's "potential" or "allowable" emissions after the change.
  - Therefore, a contemporaneous emissions increase is calculated as the positive difference between an emission unit's potential to emit just after a physical or operational change at that unit and the unit's baseline actual emissions.

- ► A decrease in actual emissions is creditable only to the extent that:
  1. The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

With respect to Item 1, the old and new levels of emissions for calculating contemporaneous decreases are established by the same method previously described for contemporaneous increases (i.e., on an actual-to-potential basis).

2. The decrease is enforceable as a practical matter at and after the time that actual construction on the particular change begins; and

   With respect to Item 2, the actual reduction must take place before the date that the emissions increase from any of the new emission units occurs. The decrease must be federally-enforceable at the time it occurred, or the applicant must demonstrate that the decrease was maintained until the present time and will continue until it becomes federally enforceable.

3. The decrease has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

   With respect to Item 3, EPA routinely assumes that an emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to an increase, unless the reviewing agency has reason to believe that this will not be the case.

- A decrease is not creditable if it was due to a change the source had to make, or will have to make, in order to bring an emission unit into compliance.

All of the contemporaneous emissions increases and decreases are identified and discussed further in the following subsections meet all of the criteria for classifications as creditable emissions changes.

To minimize improper application of the netting rules, EPA developed the following five-step procedure for calculating the net emissions increase from a proposed project (refer to Table A-5 of the NSR Workshop Manual).[31]

1. Determine the emissions increases (but not any decreases) from the proposed project. If increases are significant, proceed; if not, the sources are not subject to review.
2. Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.
3. Determine which emission units at the source experienced (or will experience, including any proposed decreases resulting from the proposed project) a creditable increase or decrease in emissions during the contemporaneous period.
4. Determine which emissions changes are creditable. Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.
5. Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.

The approach used for the Step 1 project emissions increase calculations referenced in Step 1 of EPA's netting analysis procedure was previously addressed in Sections 4.2 through 4.5. Each of the remaining steps in EPA's netting procedure are discussed in the following subsections.

[31] https://www.epa.gov/nsr/nsr-workshop-manual-draft-october-1990

4.6.1 Contemporaneous Period

Pursuant to 401 KAR 51:001, Section 1(144)(b)(2), the contemporaneous period begins on the date five years before construction commences on any portion of the proposed project and ends on the date the final emissions increase from the proposed project occurs. For setting the beginning of the contemporaneous period, applicants may use the date construction is scheduled to commence provided that it is reasonable considering the time needed to issue the final permit. The end time of the contemporaneous period does not necessarily have to coincide with the initial start-up of the last new unit to commence operation in the project scope. Rather, it must consider the time between initial start-up and commencing normal operations commonly referred to as the "shake-down period." Since the dates of construction and commencing normal operations are often unknown at the time of an applicability determination and are simply based on a scheduled date projected by the applicant, the contemporaneous period may shift if construction or initial operation does not commence as scheduled.

The proposed NGCC Project involves a series of construction activities associated with the installation of new emission units and shutdown of existing emission units. For establishing the start and end of the contemporaneous period, KU has conservatively chosen to rely on the earliest expected construction date (March 1, 2025 for start of construction of the NGCC Project) and the expected date of initial startup (April 1, 2028) associated with the list of new emission units. Based on these selected dates, the contemporaneous period for the NGCC Project runs from **March 1, 2020** to **April 1, 2028**.

4.6.2 Emissions Changes in Contemporaneous Period

Emissions changes at the Brown Generating Station that were completed in the contemporaneous period or that have been proposed and are pending are listed in chronological order as follows:

1. Installation of NGCC Project (presumed start of on-site construction is March 1, 2025) results in a PTE as shown in Table 3-2. The BAE for these new units are set to zero. The PEI for the NGCC Project is set to the PTE in Kentucky, resulting in a Step 1 emissions increases that are significant for all regulated NSR pollutants except for lead.
2. KU will permanently remove from service Unit 3 and its material handling, processing, and storage assets (presumed shutdown by April 2028), resulting in a future PTE of zero. The BAE of Unit 3 and its material handling, processing, and storage result in an equivalent contemporaneous decrease.
3. Other than the installation of a small new storage tank (IA #40 – 251-gallon Mobile Diesel Fuel Tank) that qualifies as an insignificant activity and has negligible emissions, there are no other projects that either have occurred or are projected to occur in the contemporaneous period.

None of these contemporaneous emissions changes have been relied upon in issuing a PSD permit nor have they been previously considered in any type of PSD applicability assessment for a past project. In addition, none of the aforementioned contemporaneous projects were initiated to bring an emission unit into compliance with an applicable air quality regulation. For the emission decreases within the contemporaneous period associated with the shutdown of Unit 3, KU is proposing to establish an operating limit to make this shutdown enforceable and concurrent with the commercial operation of the NGCC Unit.

4.7 PSD Applicability Summary

For each relevant regulated NSR pollutant, Table 4-1 lists the PSD SER for comparison against the project emissions increases from Steps 1 and 2 of the PSD applicability analysis.

The Step 1 project emissions increase for lead from the NGCC Project will be less than the 0.6 tpy SER. Thus, no contemporaneous netting analysis is required for this pollutant. The Step 1 project emissions increases for PM, PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, SO_2, H_2SO_4 mists, and GHG do exceed the SERs.

As such, a Step 2 contemporaneous netting analysis was performed for these pollutants to establish the project net emissions increases. This analysis demonstrates that the net emissions increases are below the SER for all regulated NSR pollutants; therefore, PSD review under Sections 8 to 16 of 401 KAR 51:017 is not necessary.

A detailed table documenting the potential emissions from new emission units on a unit-by-unit basis, the baseline actual emissions from shutdown emission units on a unit-by-unit basis, and the overall calculated new emissions increase is also provided in Section 2 of Appendix B.

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

Pollutant[1]	**"Step 1" Project Emissions Increase** (tpy)	**Creditable Contemp. Emissions Changes** (tpy)	**"Step 2" Project Net Emissions Increase** (tpy)	**PSD Significant Emission Rate**[2] (tpy)	**Project Triggers PSD Review?** (Yes/No)
PM	**104.0**	-204.6	-100.6	25	No
PM_{10}	**103.0**	-197.9	-95.0	15	No
$PM_{2.5}$	**102.0**	-169.9	-67.9	10	No
NO_X	**199.9**	-291.8	-91.9	40	No
CO	**161.4**	-138.3	**23.1**	100	No
VOC	**51.6**	-16.6	**35.0**	40	No
SO_2	**25.4**	-337.0	-311.6	40	No
H_2SO_4	**8.8**	-35.1	-26.3	7	No
Lead	0.0089	NA	NA	0.6	No
GHGs (as CO_2e)	**2,214,260**	-1,344,451	**869,809**	75,000 [3]	No

[1] Only those regulated NSR pollutants for which the project emissions increase could potentially exceed the SER are listed.

[2] Per 401 KAR 51:001, Section 1(218)(a), for 401 KAR 51:017, in reference to a *net emissions increase* of the listed pollutants at a rate of emissions that would equal or exceed any of the listed rates.
Note, Ozone: 40 tpy of VOC emissions **or** 40 tpy of NO_X emissions
$PM_{2.5}$: 10 tpy of direct $PM_{2.5}$ emissions; 40 tpy of SO_2 emissions; **or** 40 tpy of NO_X emissions, unless demonstrated not to be a $PM_{2.5}$ precursor pursuant to paragraph (207)(a)1.c.

[3] CO_2e (GHG Pollutants) only become subject to regulation and potentially applicable to PSD if another regulated NSR pollutant triggers PSD.

5. APPLICABLE FEDERAL AND STATE REQUIREMENTS

Emission units constructed as part of the proposed NGCC 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 as part of the NGCC Project. 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, DEP 7007 Form V identifies regulatory requirements for the NGCC Project. 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 D.

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 NGCC Project is presented in this section. The list of category-specific NSPS that will apply to the emission units for the NGCC Project are as follows:

- 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units – Applies to the Auxiliary Boiler (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61)
- 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines – Applies to Gas Turbine with HRSG (COMB19/58)
- 40 CFR 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units – Applies to Gas Turbine with HRSG (COMB19/58)
- 40 CFR 60 Subpart IIII – Stationary Compression Ignition Combustion Engines – Applies to the 2 MW Diesel Emergency Generator Engine (COMB21/60) and the Emergency Diesel Driven Fire Pump Engine (COMB23/63)

5.1.1 40 CFR 60 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, and mandates general control device requirements for all other subparts as applicable.

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.[32] The rule defines a fossil fuel-fired steam generating unit as:[33]

> *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 (COMB19/58) 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.[34]

The Auxiliary Boiler (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61) 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.[35] The term "steam generating unit" is defined under this regulation as:[36]

> *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 (COMB19/58) 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.[37]

The Auxiliary Boiler (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61) are each implicitly not subject since their heat input capacity is less than 250 MMBtu/hr.

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[32] 40 CFR §60.40
[33] 40 CFR §60.41
[34] 40 CFR §60.40(e)
[35] 40 CFR §60.40Da(a)
[36] 40 CFR §60.41Da
[37] 40 CFR §60.40Da(e)

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.[38] The term "steam generating unit" is defined under this regulation as:[39]

> *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 any municipal-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 (COMB19/58) 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.[40]

The Auxiliary Boiler (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61) 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 that the maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.[41] The term "steam generating unit" is defined under this regulation as:[42]

> *Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term does not include process heaters as defined in this subpart.*

The GT and HRSG with NG-fired DBs (COMB19/58) will 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 (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61), meet the definition of a steam generating unit and fall within the applicable heat input

[38] 40 CFR §60.40b(a)

[39] 40 CFR §60.41b

[40] 40 CFR §60.40b(i)

[41] 40 CFR §60.40c(a)

[42] 40 CFR §60.41c

capacity range, and each is an affected facility after the applicability date.[43] 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 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 lower heating value of the fuel fired, that are constructed, modified, or reconstructed after October 3, 1977.[44]

The GT and HRSG with NG-fired DBs (COMB19/58) 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.

5.1.7 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 (all references to GT are synonymous with a combustion turbine) and associated HRSG or DBs 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:

> "*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 (COMB19/58) 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.

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[43] 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.

[44] 40 CFR §60.330

5.1.7.1 Emissions Limits

For a new GT firing natural gas with a rating greater than 850 MMBtu/hr, the NO_X emission standard is 15 ppm at 15% O_2 or 0.43 lb/megawatt hour (MWh) gross energy output.[45] NSPS KKKK also includes, for units greater than 30 MW output, 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.[46] Compliance with the NO_X emission limit is determined on a 30-unit operating day rolling average basis.[47]

SO_2 emissions into the atmosphere from GTs 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.[48]

As documented in detail in Section 5 of Appendix B, KU's GT/DB 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.

5.1.7.2 Monitoring and Testing Requirements

Pursuant to 40 CFR §60.4333(a), the combustion turbine, 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. This requirement applies at all times including during startup, shutdown, and malfunction.

5.1.7.2.1 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.[49] 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.[50]

5.1.7.2.2 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;[51] however, KU

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[45] 40 CFR §60.4320(a) and Table 1

[46] Ibid.

[47] 40 CFR §60.4350(h), 40 CFR §60.4380(b)(1)

[48] 40 CFR §60.4330(a)(1) or (a)(2), respectively

[49] 40 CFR 60.4340(a)

[50] 40 CFR 60.4405(c)

[51] 40 CFR 60.4370(b) and (c)

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.[52] 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/Cscf 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/Cscf 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 less than 5 gr/Cscf, which is 4 times lower than the required 20 gr/Cscf.

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.

5.1.8.1 Emergency Fire Pump Engine (COMB23/63)

The NGCC Project is provisioned to have a nominal 400 hp fire pump engine that will combust ULSD. 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 400 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 hydrocarbons (NMHC)+NO_X and PM:[53]

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

As documented in the emissions calculations provided in 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.

[52] 40 CFR 60.4365

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

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.

5.1.8.2 Emergency Generator (COMB21/60)

The NGCC Project is provisioned to have a 2 MW rated emergency generator and will be a 2021 model year or later unit. Since the emergency diesel fired engine (2,682 hp) 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 rate power is greater than 560 kW, it must meet the Tier 2 standards in Table 2 to Appendix I.[54]

Table 2 to Appendix I - Tier 2 Emission Standards contain the following applicable emission limits:

- 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 0.1 g/hp-hr) of PM.

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

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.

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 engines 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.

5.1.9 NSPS Subpart TTTT – GHG Emissions for Electric Generating Units (Applicable)

40 CFR 60 *Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units* (NSPS TTTT) is applicable to any steam generating unit, integrated gasification combined-cycle, or stationary GT that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014, that:

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

Given that the proposed GT and HRSG with NG-fired DBs (COMB19/58) meets all three applicability criteria under 40 CFR §60.5509(a) and do not meet any of the exemption criteria under 40 CFR §60.5509(b), this emission unit will be subject to the provisions of NSPS TTTT.

Note that the NGCC Project is considered a base load natural gas-fired unit. By definition, such a unit must (1) combust more than 90 percent natural gas on a heat input basis on a 12-operating-month rolling average basis and (2) supply more than (i) its design efficiency or 50 percent, whichever is less, (ii) times its potential electric output as net-electric sales on both a 12-operating-month and a three-year rolling average basis.

The GT and DB will be subject to the following key requirements under NSPS TTTT:

- Per 40 CFR §60.5520(a), emissions of CO_2 must be limited to 1,000 lb/MWh of gross energy output and 1,030 lb/MWh of net energy output.
- Per 40 CFR §60.5520(d), as long as the GT is only permitted to burn uniform fuels that result in a consistent emission rate of 160 lb CO_2/MMBtu or less, it is not subject to any monitoring or reporting requirements under this subpart. KU is only required to maintain purchase records for permitted fuels.
- Per 40 CFR §60.5550, KU must submit a notification of the date of construction and actual date of initial startup of the NGCC Unit.

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

40 CFR 60 *Subpart UUUUa – Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units* (NSPS UUUUa), is applicable to steam generating units that commence construction on or before January 8, 2014. NSPS UUUUa is not applicable to the NGCC Project because it will commence construction after the applicability date, in addition to being an EGU that is subject to NSPS TTTT, which is excluded from being a designated facility per 40 CFR §60.5780a(a)(1). Moreover, pursuant to 40 CFR §60.5780a(a)(3), a stationary combustion turbine that meets the definition of a simple cycle stationary combustion turbine, a combined cycle stationary combustion turbine, or a combined heat and power combustion turbine is excluded from being a designated facility as well.

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 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 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.

Even after the shutdown of the Unit 3 Coal Boiler and its associated operations, Brown Generating Station will remain a major source for individual HAP (due to potential emissions of formaldehyde from the remaining simple cycle GTs) 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 Project is presented in this section. The list of NESHAP that will apply to the emission units for the NGCC Project are as follows:

- 40 CFR 63 Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters – Applies to Auxiliary Boiler (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61)
- 40 CFR 63 Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines – Applies to 2 MW Diesel Emergency Generator (COMB21/60) and 400 hp Emergency Diesel Driven Fire Pump Engine (COMB23/63)
- 40 CFR 63 Subpart YYYY – NESHAP for Combustion Turbines – Applies to Unit 58 GT/HRSG (COMB19/58)

5.2.1 NESHAP Subpart DDDDD – Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Applicable)

40 CFR 63 *Subpart DDDD – 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 Auxiliary Boiler (COMB20/59) that will be installed as part of the NGCC Project is an industrial boiler (99.9 MMBtu/hr) and will be located at a major HAP source. It will thus be subject to Boiler MACT. The Fuel Gas (Dewpoint) Heater (COMB22/61), which is equipped with burners with a heat input capacity of 15 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 natural gas as the sole fuel for combustion, they will be categorized as "units designed to burn gas 1 fuels" per 40 CFR §63.7499.

KU plans to provide multiple natural gas-fired HVAC units within buildings that are associated with the NGCC Project. The specific make and model will not be known until farther along in the project development phase. The total combined heat input capacity of all these small HVAC heaters can be presumed to be 10 MMBtu/hr or less and this maximum value has been used to define the total potential emissions of all the HVAC heaters. Any installation defined as a hot water heater will not be subject to Boiler MACT.[55] None of the small HVAC units are expected to be affected sources for Boiler MACT.

Pursuant to 40 CFR §63.7500(a), the Auxiliary Boiler (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61) 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 Boiler MACT. 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 and the presence of a continuous oxygen trim system that maintains an optimum air-to-fuel ratio.

- Per 40 CFR §63.7500, KU must conduct a tune-up of the Auxiliary Boiler and Fuel Gas (Dewpoint) Heater annually as specified in 40 CFR §63.7540(a)(10), unless the unit has a continuous oxygen trim system 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 7007 Form V in Appendix C.

[55] Hot water heater means, a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

5.2.2 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 MW Diesel Emergency Generator (COMB21/60) and 2) 400 hp Emergency Diesel Driven Fire Pump Engine (COMB23/63).

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., 400 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 400 hp Diesel Driven Fire Pump engine will demonstrate compliance with RICE MACT by demonstrating compliance with NSPS IIII.

For the 2 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).

5.2.3 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 (herein referenced as the GT), located at major stationary sources of HAP. The Brown Generating Station will continue to be classified as a major stationary source of HAP after the NGCC Project. The proposed GT and HRSG with NG-fired DBs (COMB19/58) meets the definition of an affected source under NESHAP YYYY and therefore will be subject to this regulation.[56] Note that the DBs and waste heat recovery units (even if part of a GT) 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 GT are dependent on the type of combustion system used lean premix or diffusion combustion system. A lean premix combustion system operates with a lower flame temperature compared to a diffusion combustion system, resulting in lower NO_X emissions. Each of the prospective vendors KU is currently evaluating, will provide the GT with DLN combustor technology. As a result, and the proposed GT is considered a lean premix natural gas-fired stationary combustion turbine as defined in 40 CFR §63.6175.

The GT will be subject to the following key requirements under NESHAP Subpart YYYY. All applicable provisions under NESHAP YYYY are documented on Form V in Appendix C.

- Per 40 CFR §§63.6095 and 63.6145, KU must submit an initial notification not later than 120 days after becoming subject to this subpart.
- Per 40 CFR §63.6100 and Table 1 of NESHAP YYYY, KU must limit the concentration of formaldehyde to 91 ppbvd or less at 15% O_2, except during turbine startup.

[56] 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

- Per 40 CFR §63.6110, KU must conduct an initial performance test within 180 days after startup of the turbines for formaldehyde.
- Per 40 CFR §63.6115, KU must conduct annual performance tests.
- Per 40 CFR §63.6125, KU must monitor on a continuous basis the oxidation catalyst inlet temperature.
- Per 40 CFR §63.6135, KU must conduct all parametric monitoring at all times the GT is operating, except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities.
- Per 40 CFR §63.6145, KU must submit an initial notification no later than 120 days after startup, a notification of intent prior to conducting the initial performance test, and a notification of compliance status for the formaldehyde emission limit.
- Per 40 CFR §63.6150, KU must submit a semiannual compliance report according to Table 6 of the subpart.
- Per 40 CFR §63.6155, KU must keep a copy of each notification, performance test, records of startup events, and records of deviations for 5 years, per 63.6160.

5.2.4 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 (EGUs) that combust coal or oil.[57] Pursuant to 40 CFR 63.9983(a), any unit designated as a major source stationary combustion turbine subject to NESHAP YYYY is not subject to MATS. Moreover, the proposed GT and HRSG with NG-fired DBs (COMB19/58) does not have the capability of firing oil. As such, it is not an affected source for MATS and will not be subject to the MATS rule.

5.3 Compliance Assurance Monitoring (40 CFR 64)

The Compliance Assurance Monitoring (CAM) regulations apply to pollutant-specific emission units at a major source under the Title V operating permit program that satisfy the following criteria as detailed in 40 CFR §64.2(a):

- The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under §64.2(b);
- The unit uses a control device to achieve compliance with any such limitation or standard; and
- The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source.

Title V permit applicants must prepare and submit a CAM Plan for subject units as part of Title V permit applications. The CAM Plans are intended to document the methods that will be followed to provide an on-going and reasonable assurance of compliance with emission limits. For a subject unit using a control device whose post-controlled emissions exceed the major source threshold (referred to as large pollutant-specific emission units [PSEU] in the rule), a CAM plan is required to be submitted with the initial Title V air operation permit application. For a subject unit, whose post-control emissions are less than the major source threshold, a CAM plan does not have to be submitted until the first Title V air operation permit renewal application.

[57] 40 CFR 63.9980

The proposed GT and HRSG with NG-fired DBs (COMB19/58) will potentially be subject to CAM requirements as it operates a control train system for NO_X, CO, and formaldehyde. NO_X is limited to 15 ppmvd at 15% O_2 pursuant to 40 CFR §60.4320 & Table 1 of NSPS KKKK. To meet these limits, KU is requiring each prospective combustion turbine vendor to guarantee a maximum NO_X emission rate of no more than 2 ppmvd at 15% O_2. The pre-controlled and post-controlled potential to emit will be above 100 tpy. KU will install, operate, and maintain a NO_X CEMS to ensure continuous compliance. The unit meets the second two CAM applicability criteria; however, since the applicable NO_X emissions standard is from NSPS KKKK, a CAA Section 112 standard that was promulgated after November 15, 1990, the emission limit is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i). Therefore, NO_X from the GT and DB are not subject to CAM requirements.

The GT and HRSG with NG-fired DBs is not subject to an emission limitation or standard for CO (or a surrogate thereof) under any applicable regulation, nor is any synthetic limit on CO emissions expected or warranted as part of the NGCC Project permit action; therefore, CAM does not apply for CO.

Formaldehyde from the GT and HRSG with NG-fired DBs is limited to 91 ppmvd at 15% O_2 pursuant to 40 CFR §63.6100 and Table 1, Item 1, of NESHAP YYYY. KU is requiring each vendor to meet the same emissions limit as NESHAP YYYY. Although the post-controlled value will be lower than 10 tpy, the pre-controlled emissions are estimated to be above 10 tpy. Therefore, the unit meets the second two CAM applicability criteria. However, since the applicable formaldehyde emissions standard is from NESHAP YYYY, a CAA Section 112 standard that was promulgated after November 15, 1990, the emission limit is exempt from CAM pursuant to 40 CFR §64.2(b)(1)(i). Therefore, formaldehyde emissions from the GT are not subject to CAM requirements.

The proposed new Mechanical Draft Cooling Tower (EQPT21/62) will be equipped with inherent drift eliminators, which are not considered a control device. Further, regardless of this designation, the drift eliminators are not needed to meet any applicable PM emission standard and thus CAM is not applicable.

None of the other emission units associated with the NGCC Project are equipped with a control device and thus are implicitly not subject to CAM.

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. Brown Generating Station stores anhydrous ammonia at levels that exceed the threshold quantity of 10,000 pounds and thus the RMP Rule currently applies. Aqueous ammonia is supplied to Unit 3's SCR (which will go away with NGCC installation). However, it is also used at the ice plant (which is labeled as a Thermal Energy Storage System in Brown's RMP plan), which is used for cooling air inlets on the simple cycle GTs and which will continue to be used.

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 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 Unit 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.[58] 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 NGCC Project will not necessitate a change to these provisions.

5.6 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)
- Clean Air Interstate Rule (CAIR) (2009 – 2014)
- Cross-State Air Pollution Rule (CSAPR) (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 combustion turbine 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) but the turbine will not be subject to the NO_X provisions (40 CFR 76) of the ARP regulations because the proposed turbine does not have the capability to burn coal. KU is required to apply for the required ARP permit at least two years prior to commencing operation of the proposed

[58] 40 CFR 82.150

turbine.[59] Under 40 CFR 75 of the ARP, KU is required to operate various CEMS for their coal-fired assets.[60] Further, the ARP requires the facility to possess SO_2 allowances for each ton of SO_2 emitted. The ARP also requires initial certification of the monitors within 90 days of commencement of commercial operation, quarterly reports, and an annual compliance certification.

5.6.2 Clean Air Interstate Rule/Cross-State Air Pollution Rule

The CAIR, 40 CFR 96, called for reductions in SO_2 and NO_X by utilizing an emissions trading program. More broadly, 40 CFR 96 also includes a forerunner to CAIR, the NO_X SIP Call / NO_X Budget program, and the name of 40 CFR 96 (NO_X Budget Trading Program for State Implementation Plans) still reflects the origins in regulating only NO_X.

A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement CAA requirements concerning the transport of air pollution across state boundaries. On July 6, 2011, the U.S. EPA finalized the Cross-State Air Pollution Rule (CSAPR). On December 30, 2011, CSAPR was stayed prior to implementation. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing an August 21, 2012, D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted EPA's request. CSAPR Phase I implementation is now in place and replaces requirements under EPA's 2005 Clean Air Interstate Rule. Therefore, the CAIR section of the permit is irrelevant now that CSAPR has replaced CAIR. Upon reviewing the existing Title V permit for Brown Generating Station, the Division makes references to replacing CAIR with CSAPR.

Units 3, EU 23 (Unit 9), EU 24 (Unit 10), EU 25 (Unit 8), EU 26 (Unit 11), EU 27 (Unit 6), EU 28 (Unit 7), and EU 29 (Unit 5) are subject to the requirements for the CSAPR NOx Annual Trading Program, CSAPR NOx Ozone Season Trading Program, and CSAPR SO_2 Trading Program.

The current permit was issued after the 2016 CSAPR update that established CSAPR NO_X Ozone Season Group 2 Trading Program requirements in 40 CFR 97 Subpart EEEEE for a subset of CSAPR-affected states (including Kentucky). These requirements were incorporated into the Kentucky SIP in 401 KAR 51:250. Furthermore, US EPA finalized the Revised CSAPR Update on March 15, 2021, which is intended to resolve outstanding interstate pollution transport obligations for 21 states (including Kentucky) for the 2008 ozone NAAQS. The Revised CSAPR Update establishes CSAPR NO_X Ozone Season Group 3 Trading Program requirements in 40 CFR 97 Subpart GGGGG. Thus, the CSAPR NO_X Ozone Season Group 3 Trading Program requirements in 40 CFR 97 Subpart GGGGG are the current requirements regulating ozone season NO_X emissions at Brown Generating Station. Upon reviewing the existing Title V permit, the Division made the necessary changes to the CSAPR NO_X Ozone Season Group 3 Trading Program for the existing sources.

CSAPR applicability is similar but distinct from ARP, with applicability criteria and definitions per 40 CFR §97.402.[61] The CSAPR NO_X Ozone Season Group 3 Trading Program regulates stationary, fossil-fuel-

[59] 40 CFR 72.30(b)(2)(ii)

[60] While not subject to ARP NO_X provisions per Part 76, Part 75 monitoring requirements for NO_X apply as referenced by CSAPR.

[61] CSAPR applicability and definitions are repeated in four separate subparts of 40 CFR 97, but each has identical definitions and applicability requirements. Subpart AAAAA (5A), which is for the NO_X Annual program, is used in this discussion.

fired boilers and *stationery, fossil-fuel-fired combustion turbines* serving, at any time, on or after January 1, 2005, a generator with a nameplate capacity exceeding 25 MWe and producing power for sale.[62]

KU's proposed combustion turbine will be an affected source under this regulation, and must comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR §§ 97.1030 through 97.1035. 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.[63]

Regarding SO_2 emissions, Unit 58 GT/HRSG (COMB19/58) will qualify as a fossil-fuel-fired *combustion turbine* as defined in 40 CFR §97.602 of the CSAPR SO_2 Group 1 Trading Program. As a CSAPR SO_2 Group 1 unit, KU is required to comply with the monitoring, recordkeeping, and reporting requirements 40 CFR 97 Subpart CCCCC and Subparts F and G of Part 75.[64] Pursuant to 40 CFR §75.11(d), KU can measure and record SO_2 emissions by one of three methods other than a SO_2 CEMS, which is the current method for the existing coal-fired boilers. KU is selecting the method shown in 40 CFR §75.11(d)(2) for the combustion turbine, where KU will provide other information satisfactory to the Administrator using the applicable procedures specified in Appendix D to 40 CFR Part 75. This appendix includes methods for default SO_2 emission rates (0.0006 lb/MMBtu), fuel flowmeters, gross calorific values, and calculated heat inputs to avoid the installation of SO_2 CEMS and flue gas flowrate monitoring.

To accommodate the NGCC Project, the Title V permit will need to be modified to include the following information in Table 5-1. These changes are reflected in the suggested permit provided in Appendix D.

[62] 40 CFR §97.1004(a)(1) Applicability

[63] 40 CFR §97.1029(a)(1) Requirements for installation, certification, and data accounting

[64] 40 CFR §97.630 General monitoring, recordkeeping, and reporting requirements

Table 5-1. Edits to SECTION L of Brown Generating Station's Title V Permit

Unit ID: Emissions Unit 58 (Unit 12, non-peaking natural gas-fired combustion turbine with natural gas-fired duct burners)					
Parameter	CEMS requirements pursuant to 40 CFR part 75, Subpart B (for SO_2 monitoring) and 40 CFR part 75, Subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil- fired units pursuant to 40 CFR part 75, Appendix D	Excepted monitoring system requirements for gas- and oil- fired peaking units pursuant to 40 CFR part 75, Appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, Subpart E
SO_2		X			
NO_X	X				
Heat Input		X			

5.7 Kentucky SIP Regulations

The new emissions units associated with the NGCC Project are also subject or potentially subject to Kentucky Administrative Regulations (401 KAR).

5.7.1 401 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 NGCC Plant Cooling Tower (EQPT21/62) 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.

5.7.2 401 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 Auxiliary Boiler (COMB20/59) and Fuel Gas (Dewpoint) Heater (COMB22/61) 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 natural gas 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 natural gas.

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 natural gas in the Brown Generating 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 natural gas.

401 KAR 59:015 was revised, effective March 9, 2018. Changes were made to the startup, shutdown, and malfunction (SSM) provisions of the rule; whereby work practice standards must be met during periods of SSM and certain procedures must be followed for startup and shutdown periods (now defined in the rule). Because both of the indirect heat exchangers associated with the NGCC Unit are subject to 40 CFR 63, Subpart DDDDD, the Auxiliary Boiler and Fuel Gas (Dewpoint) Heater 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).

5.8 Qualification as a Significant Permit Revision

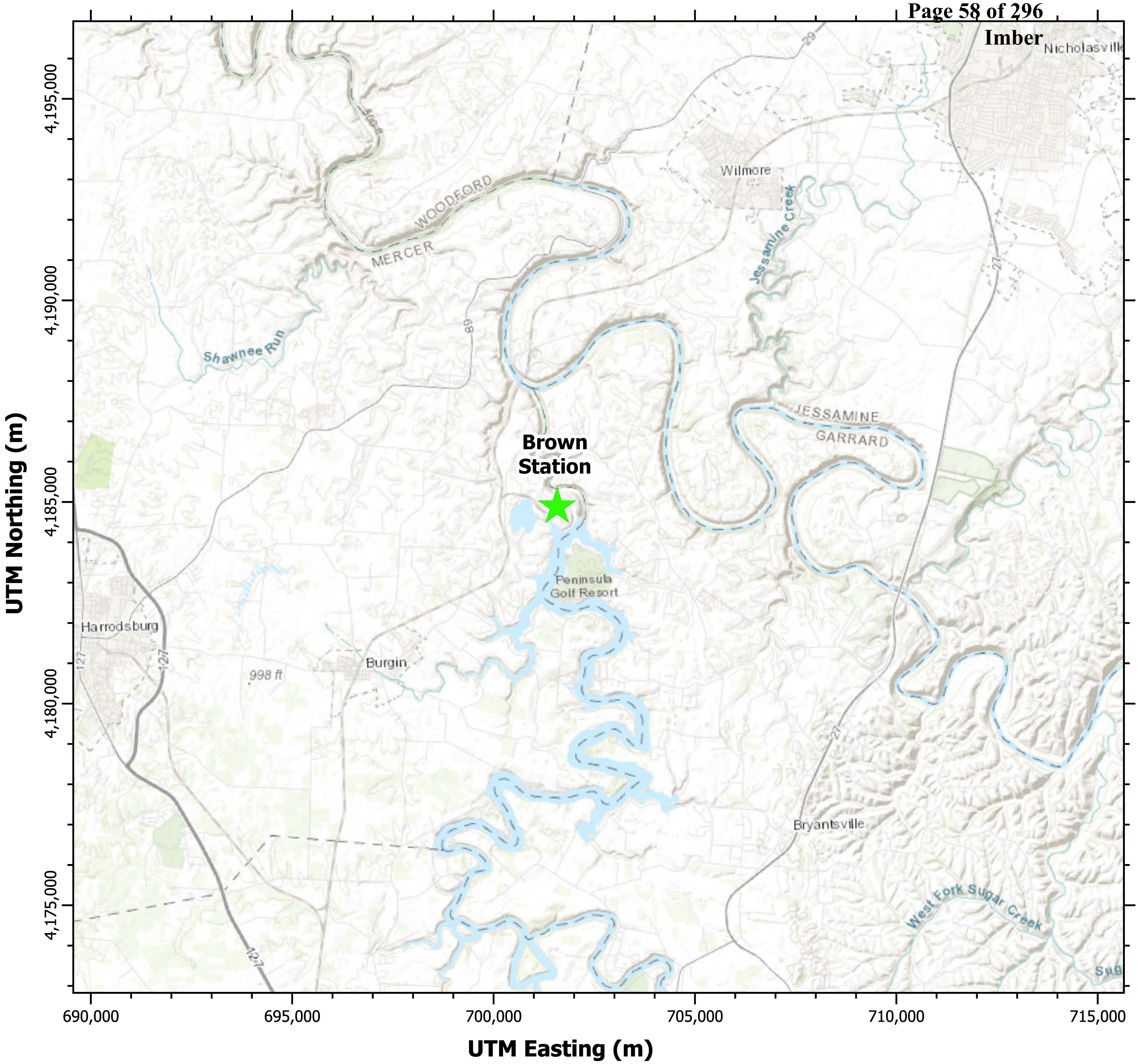
Section 16 of 401 KAR 50:020 states that significant permit revision procedures shall be used for ARP changes as well as revisions that:

(a) Involve significant changes in the monitoring requirements or a relaxation in the reporting or recordkeeping requirements contained in the permit; **or**
(b) Do not qualify as administrative permit amendments or minor permit revisions.

KU is requesting the removal of numerous emissions units and their emissions limits, operational restrictions, monitoring, recordkeeping, and reporting requirements from the permit. Moreover, the proposed NGCC Project will add new federal requirements as described in Section 5. To preclude triggering PSD in the Step 2 contemporaneous netting analysis, KU is proposing to establish an operating limit to make the Unit 3 coal boiler shutdown enforceable and concurrent with the commercial operation of the NGCC Unit. For this and the other reasons stated, the permit application will be processed as a Significant Permit Revision pursuant to 401 KAR 52:020, Section 16.

Pursuant to Section 4 and Section 16 of 401 KAR 50:020, when applying for a significant permit revision, complete applications shall be submitted using Forms DEP7007AI to DD, except that the source may only provide the information related to the change and a certification by a responsible official is also required. This application package provides information required under 401 KAR 52:020, Sections 4 and 16 for this purpose. The appropriate DEP7007 forms (AI, A, N, V, etc.) covering the NGCC Project are provided in Appendix C.

APPENDIX A. MAPS AND PROCESS FLOW DIAGRAMS



LG&E KU PPL companies LG&E-KU | Harrodsburg, KY	**Figure A-1. Area Map for E.W. Brown Generating Station in Harrodsburg, KY**		
CRS: UTM Zone 16 / NAD83 Datum	Scale: 0 2 4 km	N	**Legend** Facility
Project No: 221801.0123	Trinity Consultants 1717 Dixie Highway, Ste. 900 Covington, KY 41011		

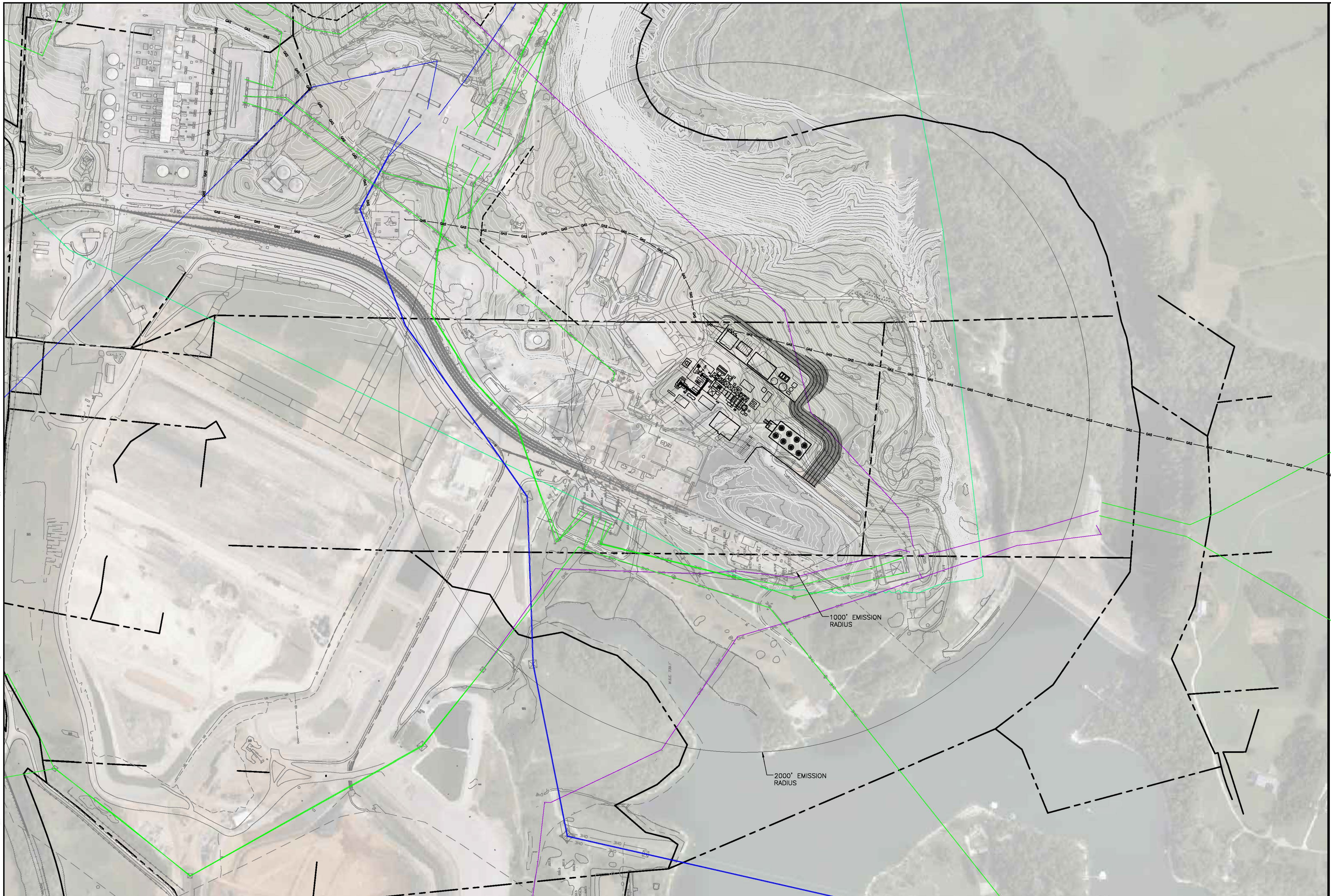
KU a PPL company

Figure A-2 Aerial Map of Brown Station Showing Arrangement of Existing Operations

Generation Services
Document Management

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

1/21/2019 10:09:55 AM



Revisions

Rev.	Project	Description	Dwn	Chkd	Appd
A	10261382	ISSUED FOR REVIEW 4 JAN 2021	SDK		
B	10343340	ISSUED FOR REVIEW 01 AUG 2022	SDK		
C	10343340	ISSUED FOR REVIEW 07 OCT 2022	SDK		

Figure A-3 Site Arrangement Drawing of New NGCC Unit Equipment (Aerial Map Overlay)

N

SITE PLAN
SCALE: 1" = 250'-0"
250 0 250 500 750

NOT TO BE USED FOR CONSTRUCTION

Location and Unit:	EW BROWN
Scale:	None
Contract No.	–
Engineering discipline:	CIVIL
Drawing type:	–
Title	EW BROWN SITE ARRANGEMENT UNIT 1-2 SITE SINGLE NGCC
Drawn:	SDK
Checked:	
Approved:	
Released for:	INFORMATION
Alternate Drawing No:	–
Originator:	HDR, INC.
Job or Project No:	10343340
Drawing No:	C2001A
Rev.	C

LG&E KU PPL companies Generation Services

DMS Version.2.0

Revisions

A Project: 10261382
ISSUED FOR REVIEW 4 JAN 2021
Dwn: SDK

B Project: 10343340
ISSUED FOR REVIEW 01 AUG 2022
Dwn: SDK

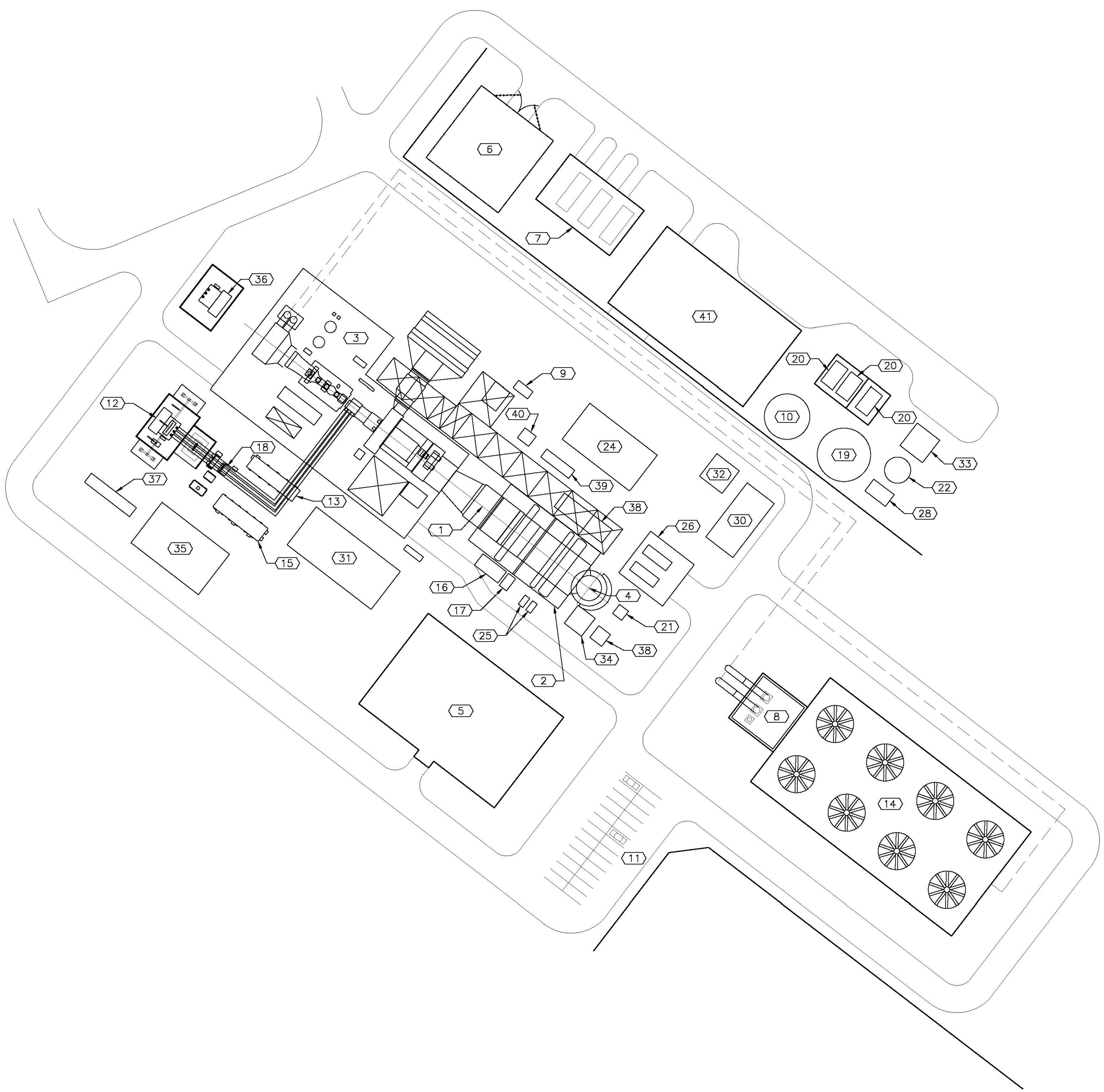
C Project: 10343340
ISSUED FOR REVIEW 07 OCT 2022
Dwn: SDK

Figure A-4 Site Arrangement Drawing of New NGCC Unit Equipment

NOT TO BE USED FOR CONSTRUCTION

HDR

Location and Unit	EW BROWN
Scale	None
Engineering discipline	CIVIL
Generation Services	LG&E KU PPL companies
Title	EW BROWN SITE ARRANGEMENT UNIT 1-2 SITE SINGLE NGCC
Originator	HDR, INC.
Job or Project No	10343340
Drawing No	C2001
Rev.	C
Released for	INFORMATION



1. GAS TURBINE (GT)
2. HEAT RECOVERY STEAM GENERATOR (HRSG)
3. STEAM TURBINE BUILDING
4. HRSG STACK
5. ADMINISTRATION/CONTROL BUILDING
6. GAS YARD
7. GAS COMPRESSOR BUILDING
8. CIRC WATER PUMPS
9. EMERGENCY GENERATOR
10. DEMIN WATER STORAGE TANK
11. PLANT PARKING
12. GSU TRANSFORMER
13. BATTERY ENCLOSURE
14. COOLING TOWER
15. EXCITATION/STATIC START ENCLOSURE
16. AMMONIA FLOW CONTROL
17. DUCT BURNER SKID
18. UNIT AUX TRANSFORMERS
19. SERVICE/FIRE WATER STORAGE TANK
20. FIRE PROTECTION PUMP HOUSE
21. CEMS SHELTER
22. WASTE WATER TANK
23. CIRC. WATER CHEMICAL FEED BUILDING
24. AUXILIARY BOILER BUILDING
25. HRSG RECIRCULATION PUMPS
26. BOILER FEED PUMP/ELECTRICAL BUILDING
27. DEMIN FORWARDING PUMPS
28. WASTE WATER PUMP SKID
29. SERVICE WATER PUMP SKID
30. AMMONIA UNLOADING/STORAGE/FORWARDING
31. SINGLE SHAFT PEECC
32. CO2 BULK STORAGE TANK
33. NITROGEN STORAGE TANK
34. HRSG BLOWDOWN TANK/PIT
35. MEDIUM VOLTAGE PDC
36. SPARE GSU TRANSFORMER
37. OIL/WATER SEPARATOR
38. HRSG BLOWDOWN SUMP
39. SAMPLE PANEL
40. CYCLE CHEMICAL FEED
41. WATER TREATMENT BUILDING

Revisions

A Project: 10261382
ISSUED FOR REVIEW
4 JAN 2021
Dwn: SDK
Chkd:
Appd:

B Project: 10343340
ISSUED FOR REVIEW
07 OCT 2022
Dwn: SDK
Chkd:
Appd:

SITE PLAN
SCALE: 1" = 50'-0"
50 0 50 100 150

NOT TO BE USED FOR CONSTRUCTION

Figure A-5 Site Arrangement Drawing of New NGCC Unit Structures and Equipment

Location and Unit: EW BROWN	Scale: None	Contract No.: –
Engineering discipline: CIVIL	Drawing type: –	
LG&E KU PPL companies	Generation Services	Drawn: ASK
Title: EW BROWN SITE ARRANGEMENT OPTION 1 SINGLE UNIT BUILD		Released for: INFORMATION
Originator: HDR, INC.	Job or Project No: 10343340	Drawing No: 0GA-C2101 Rev: B

10343340 0GA-C2101 B

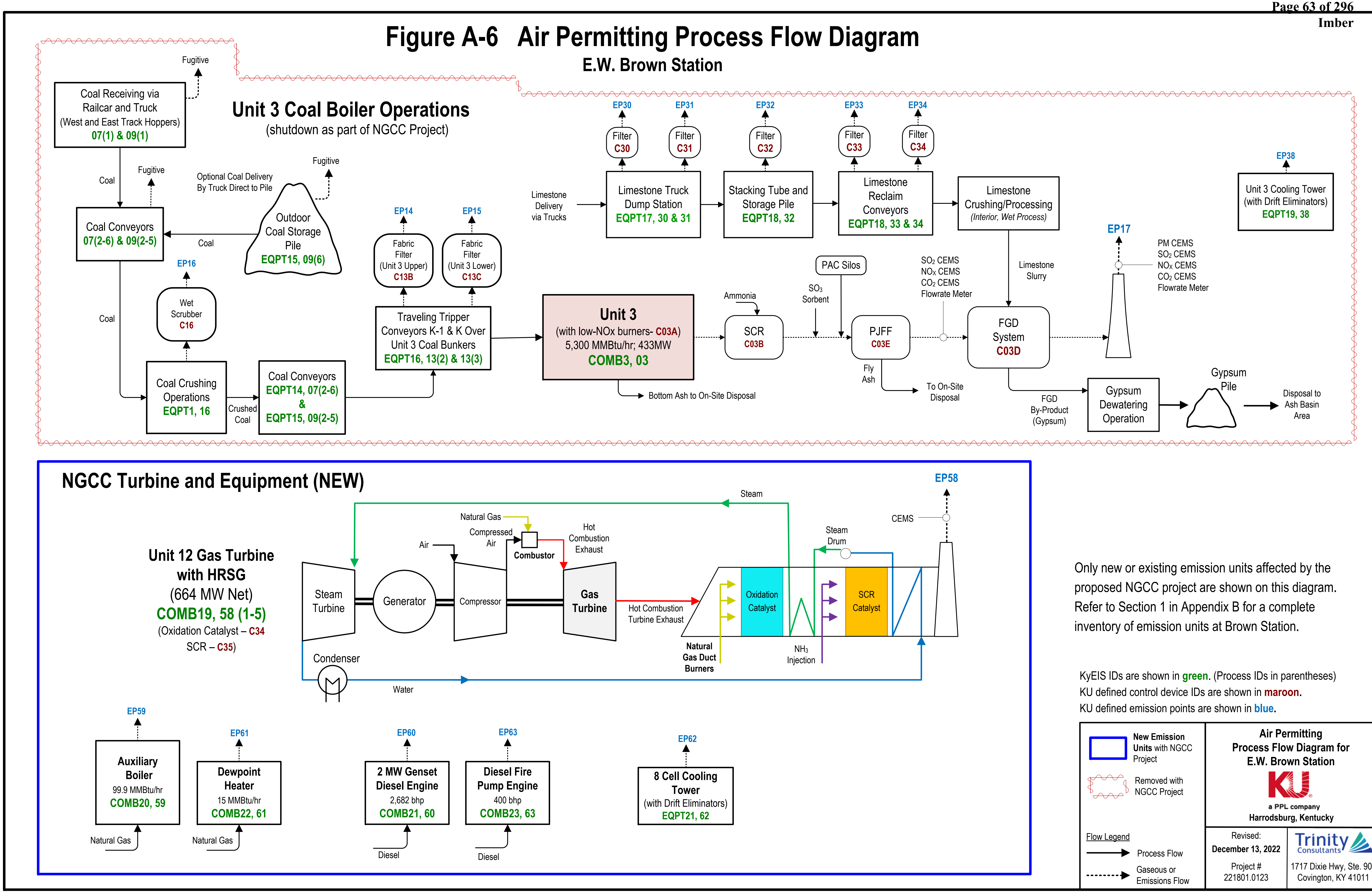


Figure A-6 Air Permitting Process Flow Diagram

APPENDIX B. EMISSIONS UNIT INDEX AND CALCULATIONS

An inventory of existing and new emission units at Brown Generating Station is provided in this appendix along with documentation showing the methodology for defining potential emissions from the new emission units associated with the NGCC Project (as reflected on the 7007 Series application forms provided in Appendix C) and the baseline actual emissions for existing emission units that are being shut down as part of the NGCC Project. The appendix is split up into the following 18 sections:

1. Brown Generating Station Emission Unit Index
2. Project Emissions Summary Table

Potential Emissions from New NGCC Project Emission Units

3. Potential Emissions Summary for New NGCC Project Emission Units
4. Potential Emissions for Gas Turbine/Duct Burners Based on Prospective Vendor Data
5. Unit 12 Gas Turbine with HRSG/Duct Burners - Emission Calculations
6. Auxiliary Steam Boiler - Emissions Calculations
7. Fuel Gas (Dewpoint) Preheater - Emissions Calculations
8. Mechanical Draft Cooling Tower – Emissions Calculations
9. Diesel-Fired Emergency Generator Engine - Emissions Calculations
10. Diesel-Fired Emergency Fire Pump Engine - Emissions Calculations
11. HVAC Heaters – Emissions Calculations *[Insignificant Activity]*
12. Lube Oil Demister Vents - Emission Calculations *[Insignificant Activity]*
13. Diesel Storage Tanks – Emissions Calculations *[Insignificant Activity]*

Baseline Actual Emissions from Existing Emission Units Being Shutdown

14. Brown Generating Station Unit 3 Boiler - Emission Reductions from Shutdowns
15. Coal Handling Operations – Emission Reductions from Shutdowns
16. Limestone Handling Operations - Emission Reductions from Shutdowns
17. Unit 3 Cooling Tower – Emission Reductions from Shutdowns
18. CCR Landfill Operations and Haul Trucks - Emission Reductions from Shutdowns

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 being installed as part of the proposed NGCC Project. Existing units being shutdown are highlighted in red. Other than units being shutdown, there are no changes being made to other existing units at the plant as part of the NGCC Project.

> 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	
50	AREA4	EU 50	1	CCR Landfill Operations and Haul Trucks	Paved Empty Bottom Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	2	CCR Landfill Operations and Haul Trucks	Paved Full Fly Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	3	CCR Landfill Operations and Haul Trucks	Paved Empty Gypsum Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	4	CCR Landfill Operations and Haul Trucks	Paved Full Bottom Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	5	CCR Landfill Operations and Haul Trucks	Paved Empty Fly Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	6	CCR Landfill Operations and Haul Trucks	Paved Full Gypsum Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	7	CCR Landfill Operations and Haul Trucks	Unpaved Empty Bottom Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	8	CCR Landfill Operations and Haul Trucks	Unpaved Full Bottom Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	9	CCR Landfill Operations and Haul Trucks	Unpaved Empty Fly Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	10	CCR Landfill Operations and Haul Trucks	Unpaved Full Fly Ash Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	11	CCR Landfill Operations and Haul Trucks	Unpaved Empty Gypsum Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	12	CCR Landfill Operations and Haul Trucks	Unpaved Full Gypsum Transport	Dust Suppression		Fugitive	Shutdown (4/1/2028)
50	AREA4	EU 50	13	CCR Landfill Operations and Haul Trucks	Travel Heavy Equip. Landfill	Dust Suppression		Fugitive	Shutdown (4/1/2028)
3	COMB3	003	1	Unit 3 Indirect Heat Exchanger	Coal	LowNOX; SCR; PJFF; FGD	C03A, B, E, D	17	Shutdown (4/1/2028)
3	COMB3	003	2	Unit 3 Indirect Heat Exchanger	#2 Fuel Oil	None		17	Shutdown (4/1/2028)
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	

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
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	
58	**COMB19**	**58**	**1**	**Unit 12 Gas Turbine with HRSG**	**Natural Gas Firing in GT & DB**	**Oxidation Catalyst; SCR**	**C34, C35**	**58**	**New (4/1/2028)**
58	**COMB19**	**58**	**2**	**Unit 12 Gas Turbine with HRSG**	**Cold Startup Events**			**58**	**New (4/1/2028)**
58	**COMB19**	**58**	**3**	**Unit 12 Gas Turbine with HRSG**	**Warm Startup Events**			**58**	**New (4/1/2028)**
58	**COMB19**	**58**	**4**	**Unit 12 Gas Turbine with HRSG**	**Hot Startup Events**			**58**	**New (4/1/2028)**
58	**COMB19**	**58**	**5**	**Unit 12 Gas Turbine with HRSG**	**Shutdown Events**			**58**	**New (4/1/2028)**
59	**COMB20**	**59**	**1**	**Auxiliary Steam Boiler**	**Natural Gas Combustion w/ LNB & FGR**			**59**	**New (4/1/2028)**
60	**COMB21**	**60**	**1**	**2 MW Diesel Emergency Generator**	**Diesel Fuel Combustion**			**60**	**New (4/1/2028)**
61	**COMB22**	**61**	**1**	**Fuel Gas (Dewpoint) Preheater**	**NG Fuel Combustion (15 MMBtu/hr)**			**61**	**New (4/1/2028)**
63	**COMB23**	**63**	**1**	**400 HP Diesel Driven Fire Pump**	**Diesel Fuel Combustion**			**63**	**New (4/1/2028)**
16	EQPT1	16	1	Coal Crushing	Four Crushers and Crusher House	Wet Scrubber	C16	16	Shutdown (4/1/2028)
21 (16)	EQPT2	21	1	Dry Fly Ash Handling	Dry Fly Ash Collection and Silo	PJFF	C21	21	Shutdown (4/1/2028)
7-1	EQPT14	07	1	Coal Handling Operations 07	West Track Hopper	Enclosures	C07A	Fugitive	Shutdown (4/1/2028)
7-2	EQPT14	07	2	Coal Handling Operations 07	Conveyor A-1	Enclosures	C07B	Fugitive	Shutdown (4/1/2028)
7-3	EQPT14	07	3	Coal Handling Operations 07	Conveyor E	Enclosures	C07C	Fugitive	Shutdown (4/1/2028)
7-4	EQPT14	07	4	Coal Handling Operations 07	Conveyor F	Enclosures	C07D	Fugitive	Shutdown (4/1/2028)
7-5	EQPT14	07	5	Coal Handling Operations 07	Conveyor G	Enclosures	C07E	Fugitive	Shutdown (4/1/2028)
7-6	EQPT14	07	6	Coal Handling Operations 07	Conveyor H	Enclosures	C07F	Fugitive	Shutdown (4/1/2028)
9-1	EQPT15	09	1	Coal Handling Operations 09	East Track Hopper	Enclosures	C09A	Fugitive	Shutdown (4/1/2028)
9-2	EQPT15	09	2	Coal Handling Operations 09	Conveyor A	Enclosures	C09B	Fugitive	Shutdown (4/1/2028)
9-3	EQPT15	09	3	Coal Handling Operations 09	Conveyor B	Enclosures	C09C	Fugitive	Shutdown (4/1/2028)
9-4	EQPT15	09	4	Coal Handling Operations 09	Conveyor C	Enclosures	C09D	Fugitive	Shutdown (4/1/2028)
9-5	EQPT15	09	5	Coal Handling Operations 09	Conveyor J	Enclosures	C09E	Fugitive	Shutdown (4/1/2028)
9-6	EQPT15	09	6	Coal Handling Operations 09	Coal Stockpile	Dust Suppression	C09F	Fugitive	Shutdown (4/1/2028)
13-1	EQPT16	13	1	Coal Handling Operations 13	Conveyor D [Tripper for Units 1 & 2]	Enclosure	C13A	13	Shutdown (4/1/2028)

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
13-2	EQPT16	13	2	Coal Handling Operations 13	Conveyor K-1 [Upper Tripper for Unit 3]	Fabric Filter	C13B	14	Shutdown (4/1/2028)
13-3	EQPT16	13	3	Coal Handling Operations 13	Conveyor K [Lower Tripper for Unit 3]	Fabric Filter	C13C	15	Shutdown (4/1/2028)
30	EQPT17	30-31	1	Limestone Unloading	Limestone Truck Dump Station #1	Fabric Filter	C30	30	Shutdown (4/1/2028)
31	EQPT17	30-31	2	Limestone Unloading	Limestone Truck Dump Station #2	Fabric Filter	C31	31	Shutdown (4/1/2028)
32	EQPT18	32-34	1	Limestone Handling	Limestone Stacking Tube	Fabric Filter	C32	32	Shutdown (4/1/2028)
33-34	EQPT18	32-34	2	Limestone Handling	Limestone Reclaim Conveyor #1 & 2	Fabric Filter	C33	33	Shutdown (4/1/2028)
38	EQPT19	36-38	3	Cooling Tower 3 (Forced Draft)	Unit 3 Cooling Tower with Drift Eliminators	Drift Eliminators		36	Shutdown (4/1/2028)
51 & 52	EQPT20	51	1	2 Cummins Emergency Engines (1220 HP Each)	Diesel			51	
62	**EQPT21**	**62**	**1**	**Mechanical Draft Cooling Tower (8 Cells)**	**Gallons of Recirculating Water**	**Drift Eliminators**	**C36**	**62**	**New (4/1/2028)**
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)					Shutdown (4/1/2028)
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)					Shutdown (4/1/2028)
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					Shutdown (4/1/2028)
IA-08				Kerosene Tank (500 gallons) - T-26 (Coal Yard/Tractor Garage Area)					
IA-09				Distillate Oil and/or Propane Coal Belt Heaters					Shutdown (4/1/2028)
IA-10				Limestone Storage Pile					Shutdown (4/1/2028)
IA-11				Limestone Reclaim Maintenance Tunnel Exhaust Vent					Shutdown (4/1/2028)
IA-12				Sorbent Storage Silos (for SO3 mitigation)					Shutdown (4/1/2028)
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					Shutdown (4/1/2028)
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					Shutdown (4/1/2028)
IA-21				Turbine oil reservoir for Unit 3 seal oil (150 gallons) - R14					Shutdown (4/1/2028)
IA-22				Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons) - R18, R19 (Unit 3, outside out of service ESP)					Shutdown (4/1/2028)
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					Shutdown (4/1/2028)
IA-26				Bottom Ash Transport					Shutdown (4/1/2028)
IA-27				Fly Ash Transport					Shutdown (4/1/2028)

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
IA-28				Gypsum Transport & Process Water System Solids					Shutdown (4/1/2028)
IA-29				Landfill Truck Loading and Unloading & Process Water System Solids					Shutdown (4/1/2028)
IA-30				Active Area of the CCR Landfill & Process Water System Solids (Wind Erosion)					Shutdown (4/1/2028)
IA-31				Slipstream Carbon Dioxide (CO2) capture System – Research					Shutdown (4/1/2028)
IA-32				Bottom Ash Handling including storage pile (associated with CCR landfill operations)					Shutdown (4/1/2028)
IA-33				Fly Ash Handling including load out to trucks (associated with CCR landfill operations)					Shutdown (4/1/2028)
IA-34				Fly Ash Filter/Separator Units (2) (associated with CCR landfill operations)					Shutdown (4/1/2028)
IA-35				Fly Ash Storage Silos (2) (associated with CCR landfill operations)					Shutdown (4/1/2028)
IA-36				Gypsum Processing including storage pile & Process Water System Solids (associated with CCR landfill operations)					Shutdown (4/1/2028)
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				**Lube Oil System with Demister Vents**	**Evaporative losses**			**IA-41**	**New (4/1/2028)**
IA-42				**Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)**	**Working and breathing losses**			**IA-42**	**New (4/1/2028)**
IA-43				**HVAC Heaters (Total <10 MMBtu/hr)**	**NG consumption**			**IA-43**	**New (4/1/2028)**

2. Project Emissions 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 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	100.10	100.10	100.10	167.17	135.90	47.82	24.68	8.69	0.01	2,149,318
COMB20	59	Auxiliary Steam Boiler	1.44	1.44	1.44	15.93	16.16	2.29	0.59	0.045	2.08E-04	51,238
COMB21	60	2 MW Diesel Emergency Generator	0.059	0.059	0.059	9.70	0.80	0.21	0.007			768
COMB22	61	Fuel Gas (Dewpoint) Preheater	0.22	0.22	0.22	2.39	4.90	0.34	0.089	0.007	3.12E-05	7,693
COMB23	63	400 HP Diesel Driven Fire Pump	0.022	0.022	0.022	0.58	0.18	0.02	0.001			115
EQPT21	62	Mechanical Draft Cooling Tower (8 Cells)	2.06	0.97	0.0042							
	IA-41	Lube Oil System with Demister Vents						0.66				
	IA-42	Diesel Storage Tanks for NGCC						0.0011				
	IA-43	HVAC Heaters (Total <10 MMBtu/hr)	0.14	0.14	0.14	4.16	3.49	0.23	0.059	0.005	2.08E-05	5,129
Subtotal			104.04	102.95	101.99	199.92	161.44	51.57	25.43	8.75	0.01	2,214,260
Emission Decreases from Units Being Shutdown with Project												
COMB3	003	Unit 3 Indirect Heat Exchanger	-200.1	-194.6	-167.6	-291.8	-138.3	-16.6	-337.0	-35.1	-0.04	-1,344,451
EQPT1	16	Coal Crushing	-0.055	-0.028	-0.006	--	--	--	--	--	--	--
EQPT14	07	Coal Handling Operations 07	-0.052	-0.052	-0.010	--	--	--	--	--	--	--
EQPT15	09	Coal Handling Operations 09	-0.149	-0.071	-0.014	--	--	--	--	--	--	--
EQPT16	13	Coal Handling Operations 13	-0.019	-0.019	-0.015	--	--	--	--	--	--	--
EQPT17	30-31	Limestone Unloading	-0.073	-0.073	-0.014	--	--	--	--	--	--	--
EQPT18	32-34	Limestone Handling	-0.004	-0.004	-0.004	--	--	--	--	--	--	--
EQPT19	36-38	Cooling Tower 3 (Forced Draft)	-2.069	-2.069	-2.069	--	--	--	--	--	--	--
AREA4	EU 50	CCR Landfill Operations and Haul Trucks	-2.100	-1.028	-0.103	--	--	--	--	--	--	--
SubTotal			-204.6	-197.9	-169.9	-291.8	-138.3	-16.55	-337.0	-35.1	-0.04	-1,344,451
Emissions Increase Summary												
Net Project Emission Increases			**-101**	**-95**	**-68**	**-92**	**23**	**35**	**-312**	**-26**	**-0.03**	**869,809**
PSD/NSR Major Modification Threshold			25	15	10	40	100	40	40	7	0.6	75,000
Trigger PSD/NSR?			**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	No*

* CO2e (GHG Pollutants) only become subject to regulation and potentially applicable to PSD if another regulated NSR pollutant triggers PSD.

3. 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	100.10	100.10	100.10	167.17	135.90	47.82	24.68	8.69	0.01	2,149,318
COMB20	59	Auxiliary Steam Boiler	1.44	1.44	1.44	15.93	16.16	2.29	0.59	0.045	2.1E-04	51,238
COMB21	60	2 MW Diesel Emergency Generator	0.059	0.059	0.059	9.70	0.80	0.21	0.007			768
COMB22	61	Fuel Gas (Dewpoint) Preheater	0.22	0.22	0.22	2.39	4.90	0.34	0.089	0.007	3.1E-05	7,693
COMB23	63	400 HP Diesel Driven Fire Pump	0.022	0.022	0.022	0.58	0.18	0.02	0.001			115
EQPT21	62	Mechanical Draft Cooling Tower (8 Cells)	2.06	0.97	0.0042							
	IA-41	Lube Oil System with Demister Vents						0.66				
	IA-42	Diesel Storage Tanks for NGCC						0.0011				
	IA-43	HVAC Heaters (Total <10 MMBtu/hr)	0.14	0.14	0.14	4.16	3.49	0.23	0.059	0.005	2.08E-05	5,129
Subtotal			104.04	102.95	101.99	199.92	161.44	51.57	25.43	8.75	8.9E-03	2,214,260

Emission Unit ID		Description	NH3 (tpy)	Acetaldehyde (tpy)	Formaldehyde (tpy)	Hexane (tpy)	Toluene (tpy)	Xylenes (tpy)	Nickel (tpy)	Mercury (tpy)	Total HAP (tpy)
New Emission Units											
COMB19	58	Unit 12 Gas Turbine with HRSG	122.76	3.10	3.95	15.56	1.15	0.56	3.63E-02	4.50E-03	25.14
COMB20	59	Auxiliary Steam Boiler			3.1E-02	0.75	1.4E-03		8.73E-04	1.08E-04	0.78
COMB21	60	2 MW Diesel Emergency Generator		1.2E-04	3.7E-04		1.3E-03	9.1E-04			8.0E-03
COMB22	61	Fuel Gas (Dewpoint) Preheater			4.7E-03	0.112	2.1E-04		1.31E-04	1.62E-05	0.12
COMB23	63	400 HP Diesel Driven Fire Pump		5.4E-04	8.3E-04		2.9E-04	2.0E-04			2.8E-03
EQPT21	62	Mechanical Draft Cooling Tower (8 Cells)									
	IA-41	Lube Oil System with Demister Vents									
	IA-42	Diesel Storage Tanks for NGCC									
	IA-43	HVAC Heaters (Total <10 MMBtu/hr)			3.1E-03	7.5E-02	1.4E-04		8.7E-05	1.1E-05	0.079
Subtotal			122.76	3.10	3.99	16.50	1.15	0.57	3.74E-02	4.63E-03	26.13

4. Potential Emissions for Gas Turbine/Duct Burners Based on Prospective Vendor Data

> Kentucky Utilities Company (KU) is choosing between three vendors for the new 640-664 MW (net) natural gas combined cycle electric generating plant (herein labeled as NGCC). Sections 4 and 5 provide the derivation of the emission factors, heat input, and potential emissions. The NGCC system will consist of one power block with one NG-fired gas turbine (GT) and its single-shaft water cooled generator, one heat recovery steam generator (HRSG) with NG-fired duct burners (DB), and one steam turbine generator (STG) arranged in a one-on-one configuration. The GT will be either a 1x1 7HA.03, 501JAC, 1x1 9000HL, or similar unit, all of which are the largest and most efficient turbines currently in the market

> Each vendor provided emissions data for a number of cases that bracket the range of possible operating conditions such as the coldest/hottest day, a representative winter day at 15°F, average temperature day at 57°F, and representative summer day at 90°F. The following shows the highest emissions profile at 15, 57, and 90°F, as well as the outlier cases, with the highest hourly emissions rate by pollutant. If the DB is also operational and providing additional heat input, such as during the summer cases, it is shown as well in the load description. Not shown are 75% or minimum load situations because in every one of those low load cases, the hourly emissions rate is less than the corresponding 100% load case. Another variation that occurred in the summer months was the possible operation of an evaporative cooler (EC).

4.1 Vendor A: Calculated Stack Emission Rates for GT/DB

Case	Ambient Temp. (°F)	Load (%)	Load Description	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Total PM (lb/hr)	SO_2 (lb/hr)	H_2SO_4* (lb/hr)	NH_3 (lb/hr)	CO_2 (lb/hr)
4	15	100	GT	30.6	18.6	5.3	18.0	7.1	4.8	28.3	548,000
10	57	100	GT	30.0	18.3	5.2	17.9	7.0	4.7	27.8	537,000
13	90	100	GT + EC + DB	30.6	18.6	**10.7**	19.4	7.1	**5.1**	28.3	547,000
17	106	100	GT + EC + DB	29.8	18.2	10.4	**19.7**	6.9	5.0	27.6	534,000
1	-18	100	GT	**30.7**	**18.7**	5.3	18.0	7.1	4.8	**28.4**	**549,000**
Max of 20		Varies		**30.7**	**18.7**	**10.7**	**19.7**	**7.1**	**5.1**	**28.4**	**549,000**

* When asked by KU to provide emissions for H2SO4, only Vendor A provided data. H2SO4 is generated from the following simplified chemical conversion: Fuel-based sulfur => SO2 => SO3 => H2SO4. SO3 is generated in the combustion process and varies depending on both the chosen oxidation catalyst and SCR catalyst. Vender A's overly conservative conversion rates for SO3 generation resulted in H2SO4 hourly emissions being 70% of SO2. As shown in Section 5.3.1, KU used a more realistic, yet conservative, conversion rate.

Startup/Shutdown Events	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
5 cold start events (total pounds)	2,100	1,550	500	160	-	-	-	-
45 warm start events (total pounds)	11,700	10,350	3,825	1,215	-	-	-	-
100 hot start events (total pounds)	13,500	20,000	8,000	1,400	-	-	-	-
150 shutdown start events (total pounds)	6,000	26,250	9,000	750	-	-	-	-
Sum of all Events (total tons)	**16.7**	29.1	10.7	**1.8**	-	-	-	-

Sample Calculations:
Total Emissions from SUSD Events: NOx (tpy) = (2,100 lb for C-SU + 11,700 lb for W-SU + 13,500 lb for H-SU + 6,000 lb for Shutdowns) / 2,000 lb/ton = 16.7 tpy

4.2 Vendor B: Calculated Stack Emission Rates for GT/DB

Case	Ambient Temp. (°F)	Load (%)	Load Description	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Total PM (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)	NH_3 (lb/hr)	CO_2 (lb/hr)
16	15	100	GT	31.0	19.0	5.3	19.9	-	-	-	-
12	57	100	GT	31.0	19.0	5.4	20.1	-	-	-	-
5	90	100	GT + EC + DB	**32.0**	**19.0**	**10.9**	**23.3**	-	-	-	-
Max of 11		Varies		**32.0**	**19.0**	**10.9**	**23.3**	-	-	-	-

Startup/Shutdown Events	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
5 cold start events (total pounds)	360	2,665	675	150	-	-	-	-
45 warm start events (total pounds)	2,925	21,420	5,445	1,125	-	-	-	-
100 hot start events (total pounds)	5,500	30,300	9,100	1,500	-	-	-	-
150 shutdown start events (total pounds)	11,700	29,250	17,700	750	-	-	-	-
Sum of all Events (total tons)	10.2	**41.8**	**16.5**	1.8	-	-	-	-

4.3 Vendor C: Calculated Stack Emission Rates for GT/DB

Case	Ambient Temp. (°F)	Load (%)	Load Description	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	Total PM (lb/hr)	SO_2 (lb/hr)	H_2SO_4 (lb/hr)	NH_3 (lb/hr)	CO_2 (lb/hr)
15	15	100	GT	30.1	18.3	5.3	14.9	-	-	27.9	-
9	57	100	GT	28.8	17.5	5.0	14.1	-	-	26.6	-
21	90	100	GT + EC + DB	29.6	18.0	**10.3**	**16.4**	-	-	27.4	-
18	-18	100	GT + EC	**30.2**	**18.4**	5.3	14.9	-	-	**28.0**	-
Max of 21		Varies		**29.6**	**18**	**10.3**	**16.4**	-	-	**27.4**	-

Startup/Shutdown Events	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
5 cold start events (total pounds)	540	3,790	350	33	-	-	-	-
45 warm start events (total pounds)	2,655	12,825	2,025	216	-	-	-	-
100 hot start events (total pounds)	5,900	28,500	4,500	480	-	-	-	-
150 shutdown start events (total pounds)	6,900	36,600	7,350	600	-	-	-	-
Sum of all Events (total tons)	8.0	40.9	7.1	0.7	-	-	-	-

4.4 Comparison of Annual Emissions by Operating Scenario and Vendor

> The following represents the annual emissions by operating scenario:

1) Profile 1 calculates the annual emissions using 8,760 hours at the highest hourly emissions rate at the average ambient temperature. In every case, DBs will not be necessary to generate the rated output.
2) Profile 2A calculates the annual emissions with 2,000 hr/yr of operation at 15°F, 4,760 hr/yr at 57°F, and 2,000 hr/yr at 90°F. The DBs and EC only kick in during the summer months. Although it artificially elevates the potential emission rate, for simplicity and conservatism, the total hours do not subtract periods of non-operation between a shutdown and a startup, nor do the total hours exclude the total time of GT operation during the events.
3) Profile 2B is the same as 2A except 127 hours of time for SUSD events is subtracted. Again, this case does not subtract periods of non-operation between a shutdown and a startup. Where, 127 hrs = (5 C-SU events * average of 40 & 70 min C-SU + 45 W-SU events * average of 30 & 60 min W-SU + 100 H-SU events * average of 21 & 35 min H-SU + 150 SD events * average of 12 & 21 min SD) * 60 mn/hr
4) Profile 3 is the maximum hourly emissions rate for any case multiplied by 8,760 hr/yr.

Emissions Profile	**Underlying Heat Input** (MMBtu/hr)	**NO_X** (tpy)	**CO** (tpy)	**VOC** (tpy)	**Total PM** (tpy)	**SO_2** (tpy)	**H_2SO_4** (tpy)	**NH_3** (tpy)	**CO_2** (tpy)
Profile 1: 8,760 hr/yr at 57 °F									
Vendor A (GT only)	4,124	131.4	80.2	22.8	78.4	30.7	20.6	121.8	2,352,060
Vendor B (GT only)	3,858	135.8	83.2	23.7	88.0				
Vendor C (GT only)	3,751	126.1	76.7	21.9	61.8			116.5	
Profile 2A: 2,000 hr/yr at 15 °F, **4,760** hr/yr at 57 °F, and 2,000 hr/yr at 90 °F									
Vendor A (GT + EC + DB)	**4,157**	132.6	80.8	28.4	80.0	**30.9**	**21.1**	**122.8**	**2,373,060**
Vendor B (GT + EC + DB)	3,850	**136.8**	**83.2**	**29.1**	**91.0**				
Vendor C (GT + EC + DB)	3,817	128.2	78.0	27.5	64.9			118.6	
Profile 2B: 2,000 hr/yr at 15 °F, **4,633** hr/yr at 57 °F, and 2,000 hr/yr at 90 °F									
Vendor A (GT + EC + DB)	4,097	130.7	79.6	28.0	78.9	30.4	20.8	121.0	2,338,961
Vendor B (GT + EC + DB)	3,794	134.8	82.0	28.7	89.8				
Vendor C (GT + EC + DB)	3,762	126.4	76.8	27.2	64.0			116.9	
Profile 3: 8,760 hr/yr at maximum hourly emissions for all operating scenarios									
Vendor A (GT + EC + DB)	4,216	134.5	81.9	46.9	86.3	31.1	22.3	124.4	2,404,620
Vendor B (GT + EC + DB)	3,854	140.2	83.2	47.7	102.1				
Vendor C (GT + EC + DB)	3,942	129.6	78.8	45.1	71.8			120.0	

Sample Calculations:
For Profile 1, Vendor A: NOx (tpy) = 30.0 lb/hr (for 57F, Case 10) x 8,760 hr/yr / 2,000 lb/ton = 131.4 tpy
For Profile 2A, Vendor B: NOx (tpy) = (31.0 lb/hr @15F x 2,000 hr/yr + 31.0 lb/hr @57F x 4,760 hr/yr + 32.0 lb/hr @90F x 2,000 hr/yr) / 2,000 lb/ton = 136.8 tpy

4.5 Defined PTE on a Seasonal Basis Determined Using Max Hourly Emission Rates by Vendor

> In reviewing the calculated annual emissions for the worst case operating scenarios presented in Section 4.4, KU has chosen to represent the potential emissions for the GT/DB based on Profile 2A. Profile 3 is not used because it is not practically realistic and could never occur in practice. While Profile 2A is also conservative, in that it does not subtract for SUSD hours (which is done in Profile 2B), the differences are not significant. Profile 2A, which considers the differences for cold and hot seasons, also predicts slightly higher potential emissions than the baseload case at the average ambient temperature. Thus, it is conservative but reasonable to use emissions for Profile 2A to define the PTE.

Selected Emissions Profile	NO_X (tpy)	CO (tpy)	VOC (tpy)	Total PM (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	NH_3 (tpy)	CO_2 (tpy)
Profile 1: 8,760 hr/yr at 57 °F								
Maximum by Vendor (tpy)	135.8	83.2	23.7	88.0	30.7	20.6	121.8	2,352,060
Profile 2A: 2,000 hr/yr at 15 °F, 4,760 hr/yr at 57 °F, and 2,000 hr/yr at 90 °F								
Maximum by Vendor (tpy)	136.8	83.2	29.1	91.0	30.9	21.1	122.8	2,373,060
Worst case GT PTE (Profile 2A)								
Maximum by Vendor (tpy) of Profile 1 or 2A	**136.8**	**83.2**	**29.1**	**91.0**	**30.9**	**21.1**	**122.8**	**2,373,060**
Maximum by Pollutant from Events (tpy)	**16.7**	**41.8**	**16.5**	**1.8**	0	0	0	0

4.6 Derivation of Emission Factors Based on Hourly Average Emission Rate

> Based on the defined PTE values (tpy), the equivalent hourly average emission rate (lb/hr) can be calculated. An emission factor in terms of lb/MMBtu can then be calculated based on the vendor-provided heat input associated with the case for which the PTE value is derived. See Section 4.4, which provides the underlying heat input rate.

> Emission factors in terms of lb/MMscf of gas fired are calculated based on the nominal average heating value of natural gas received at the E.W. Brown Station of 1,053 Btu/scf.

Selected Emissions Profile	NO_X	CO	VOC	Total PM	SO_2	H_2SO_4	NH_3	CO_2
Steady-State Stack Exhaust Emissions (lb/hr)								
Equivalent hourly emissions rate (Annual emissions for 2A in tpy x 2000 lb/ton / 8,760 hours)	31.23	19.00	6.63	20.78	7.05	4.81	28.03	541,795
Heat Input (MMBtu/hr, HHV)								
Weighted vendor-provided heat inputs (HHV) (highest is 4,157 MMBtu/hr for Vendor A)	3,850	3,850	3,850	3,850	**4,157**	**4,157**	**4,157**	**4,157**
Natural Gas Fuel Consumption (MMscf/hr)								
Steady State = Heat Input (MMBtu/yr, HHV) / NG HHV (Btu/scf) / 8,760 hr/yr	3.656	3.656	3.656	3.656	**3.948**	**3.948**	**3.948**	**3.948**
Steady-State Emission Factor (lb/MMBtu, HHV)								
Emission factor associated with gas combustion during steady-state operation of GT + DB	**0.00811**	**0.00493**	**0.00172**	**0.00540**	0.00169	0.00116	**0.00674**	**130.34**
Steady-State Emission Factor (lb/MMscf, HHV)								
Emission factor converted to lb/MMscf based on average gas HV of 1,053 Btu/scf	**8.541**	**5.196**	**1.814**	**5.684**	1.785	1.220	**7.100**	**137,249**

Sample Calculations:
Steady-State Stack Exhaust Emissions: NOX (lb/hr) = 136.8 tpy x 2,000 lb/ton / 8,760 hr/yr = 31.23 lb/hr
Maximum Natural Gas Fuel Consumption = 4,157 MMBtu/hr (maximum for any pollutant) / 1,053 MMBtu/MMscf = 3.948 MMscf/hr
NOx Emission Factor (lb/MMBtu) = 31.23 lb/hr / 3,850 MMBtu/hr = 0.00811 lb/Mmbtu
NOx Emission Factor (lb/MMscf) = 31.23 lb/hr / 3.656 MMscf/hr = 8.541 lb/MMscf

5. Unit 12 Gas Turbine with HRSG/Duct Burners - Emission Calculations

> Emission factors and control efficiencies for the pollutants represented on the forms for the new GT/DB along with calculated potential emissions are documented in this section.

5.1 Description and Nomenclature

> The new emission unit identification and associated process IDs proposed to be assigned within the Kentucky Emissions Inventory System (KyEIS) for the GT/DB are shown below. Both the GT and DB fire natural gas solely and Process ID 1 includes the natural gas fired in the GT and DB because both are exhausted through the same add-on control devices before exiting the stack. Process IDs 2 through 5 encompass possible startup and shutdown operating events, consistent with conventional approaches for representing emissions from combustion turbines.

GT/DB KyEIS Equipment and Source IDs and Descriptions	Process ID#
COMB19, 58 - Unit 12 Gas Turbine with HRSG	
Natural Gas Firing in GT & DB	1
Cold Startup Events	2
Warm Startup Events	3
Hot Startup Events	4
Shutdown Events	5

5.2 Capacity and Fuel Information for 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.

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	
Maximum operating hours/yr used in permitting	8,760	hr/yr	KU did not take any reductions for time between events.
Total hours estimate for summer season	2,000	hr/yr	
Total hours estimate for fall and spring	4,760	hr/yr	
Total hours estimate for winter season	2,000	hr/yr	
Maximum operating hours/yr accounting for SUSD events	*5,314*	*hr/yr*	*Although not used in calculations, this is the actual estimate of operating hours IF KU excluded time for every SUSD event and time in between events*
Maximum Short-term Heat Input Capacity (for information only; not used in the	*4,216*	*MMBtu/hr*	*Max of three vendors out of all cases (Vendor A, Case 1 = GT only at -18°F and 100% of baseload)*
Maximum Short-term Fuel Consumption (for information only; not used in the calculations)	*4.004*	*MMscf/hr*	*= 4,216 MMBtu/hr / 1,053 Btu/scf*
Maximum Simulated Heat Input Capacity Used for Emission Calculations	**4,157**	MMBtu/hr	Weighted vendor-provided heat inputs (HHV) (highest is 4,157 MMBtu/hr for Vendor A), see Section 4.6.
Maximum Simulated Fuel Consumption	3.948	MMscf/hr	= 4,157 MMBtu/hr / 1,053 Btu/scf
Maximum Simulated Fuel Consumption	34,580	MMscf/yr	= 8,760 hr/yr * 3.948 MMscf/hr
SCC Code:	20100201	Electric Generation (2-01), Turbine (2-01-002-01)	
SCC Units:		Million Cubic Feet Natural Gas Burned (MMscf)	

5.3 Derivation and Documentation of Steady-State Operation Emission Factors

5.3.1 NSR-Regulated Pollutants

> Controlled emission factors (EFs) for all NSR-regulated pollutants have been calculated as described in Section 4 for the worst-case annual operating profile out of the four scenarios described therein. 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	ppmvd @ 15% O2	KU's vendor guarantee requirement for NGCC
Controlled Emission Factor	**8.541**	lb/MMscf	See Section 4.6 for derivation
Controlled Emission Rate	33.71	lb/hr	= 8.541 lb/MMscf x 3.948 MMscf/hr
Control Efficiency (**not guaranteed**)	90	%	Nominal value for a SCR selected for purposes of defining an uncontrolled emission factor. Ranges between 75% and 91% depending on available nitrogen content and GT combustor design/operation.
Uncontrolled Emission Factor	85.406	lb/MMscf	= 8.541 lb/MMscf / (100% - 90%)

CO

Concentration in stack exhaust after oxidation catalyst	2	ppmvd @ 15% O2	KU's vendor guarantee requirement for GT
Controlled Emission Factor	**5.196**	lb/MMscf	See Section 4.6 for derivation
Controlled Emission Rate	20.51	lb/hr	= 5.196 lb/MMscf x 3.948 MMscf/hr
Control Efficiency (**not guaranteed**)	90	%	Nominal value for a oxidation catalyst
Uncontrolled Emission Factor	51.963	lb/MMscf	= 5.196 lb/MMscf / (100% - 90%)

VOC

Concentration in Stack Exhaust	1.23	ppmvd @ 15% O2	KU's vendor guarantee requirement for GT
Controlled Emission Factor	**1.814**	lb/MMscf	See Section 4.6 for derivation
Controlled Emission Rate	7.16	lb/hr	= 1.814 lb/MMscf x 3.948 MMscf/hr
Control Efficiency (**not guaranteed**)	50	%	Based on expected VOM control efficiency from catalytic oxidation.
Uncontrolled Emission Factor	3.628	lb/MMscf	= 1.814 lb/MMscf / (100% - 50%)

SO_2

> All vendors were 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	lb/Cscf	
Max actual sulfur content for pipeline gas in last 5 yrs	*0.116*	*lb/Cscf*	*Cited for informational purposes only.*
Molecular Weight of S	32.07	lb/lbmol	
Molecular Weight of SO2	64.07	lb/lbmol	
Uncontrolled Emission Rate	5.63	lb/hr	= 0.5 lb/Cscf x 10,000 Cscf/MMscf / 7,000 gr/lb / 1,053 x 4,157 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	= 5.63 lb/hr / 3.948 MMscf/hr
Uncontrolled Emission Factor	0.0014	lb/MMBtu	= 5.63 lb/hr / 4,157 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 the following citation, "Pages 6-4 & 6-5 of Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: 2018 Update. EPRI, Palo Alto, CA: 2018. 3002012398", where the total conversion assumes 10% conversion for GT/DB + 3% for SCR + 10% for oxidation catalyst.

Molecular Weight of SO3	80.06	lb/lbmol	
Estimated SO2 to SO3 Conversation Rate	23%	10% conversion in GT/DB + 3% for SCR + 10% conversion across catalyst	
Estimated SO3 to H2SO4 Conversion Rate	100%	Conservative assumption	
Molecular Weight of H2SO4	98.08	lb/lbmol	
Uncontrolled Emission Rate of H2SO4	1.98	lb/hr	= 5.63 lb/hr SO2 * 23% SO2 to SO3 * 80.06 lb/lbmol SO3 / 64.07 lb/lbmol SO2 * 1 lbmole SO3 / 1 lbmole SO2 * 100% SO3 to H2SO4 * 98.08 lb/lbmol H2SO4 / 80.06 lb/lbmol SO3 * 1 lbmol H2SO4 / 1 lbmol SO3
Uncontrolled Emission Factor of H2SO4	0.503	lb/MMscf	= 1.98 lb/hr / 3.948 MMscf/hr

$PM/PM_{10}/PM_{2.5}$

> Steady-state generation of PM should be negligible from this NGCC system. For example, one prospective GT/DB vendor stated the following in their documentation, "PM-10 emissions from natural gas combustion are essentially zero (no emissions from the combustion process itself). The reported levels in the gathered data are due to non-combustion factors, which include test sampling and construction debris." When KU asked each vendor to provide PM estimates, all vendors 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 vendors 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 Factor	**5.684**	lb/MMscf	See Section 4.6 for derivation
Uncontrolled Emission Factor	0.0054	lb/MMBtu	= 5.684 lb/MMscf / 1,053 Btu/scf
Uncontrolled Emission Rate	22.44	lb/hr	= 5.684 lb/MMscf x 3.948 MMscf/hr

Greenhouse Gases

> Emission factors for CO2 are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Table C-1). AP-42 emission factors in Section 3.1 have been used for the CH4 and N2O emission factors.

> 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	123,177	lb/MMscf	= 116.98 lb/MMBtu * 1,053 MMBtu/MMscf
Uncontrolled Emission Rate	486,246	lb/hr	= 123,177 lb/MMscf x 3.948 MMscf/hr

CH_4

Uncontrolled Emission Factor	0.0086	lb/MMBtu	AP-42 Section 3.1 Stationary Gas Turbines, Table 3.1-2a
	8.772	lb/MMscf	= 0.0086 lb/MMBtu x 1,020 MMBtu/MMscf per AP-42

N_2O

Uncontrolled Emission Factor	0.0030	lb/MMBtu	AP-42 Section 3.1 Stationary Gas Turbines, Table 3.1-2a
	3.060	lb/MMscf	= 0.0030 lb/MMBtu x 1,020 MMBtu/MMscf per AP-42

CO_2e

Global Warming Potentials of GHGs per 40 CFR 98 Subpart A, Table A-1.

CO2	1
CH4	25
N2O	298

Uncontrolled Emission Factor	124,308	lb/MMscf	(CO2 EF) + (CH4 EF x CH4 GWP) + (N2O EF x N2O GWP)

5.3.2 Ammonia (from Ammonia Slip in SCR)

NH_3

Concentration in stack exhaust	5 ppmvd @ 15% O2		KU's vendor guarantee requirement for NGCC
Uncontrolled Emission Factor	**7.100** lb/MMscf	See Section 4.6 for derivation	
Uncontrolled Emission Rate	28.03 lb/hr	= 7.100 lb/MMscf x 3.948 MMscf/hr	

5.3.3 Hazardous Air Pollutants for GT

Formaldehyde

Concentration in stack exhaust	0.091 ppmvd @ 15% O2	KU's vendor guarantee 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 Vendor A's derived Fd at ~8638 dscf/MMBtu.
Uncontrolled Emission Rate	0.90 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 4,157 MMBtu/hr
Uncontrolled Emission Factor	0.229 lb/MMscf	= 0.90 lb/hr / 3.948 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 Uncontrld EF (lb/MMBtu)	GT Uncontrld 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%	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	68%	2.2E-04	2.3E-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.

5.3.4 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 Uncontrld EF (lb/MMBtu)	DB Uncontrld EF (lb/MMscf)	Oxidation Catalyst Control Efficiency[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	AP42 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.

5.4 NGCC Potential Emissions Summary - Steady State Operations

> The following represents the potential emissions assuming the GT+DB combust natural gas at 4,157 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. Also, the size of the NG-fired DBs are ≤ 296 MMBtu/hr, yet if there was an EF that had a greater lb/MMscf for DB operation, it was used in the PTE, which also adds conservatism to the estimated PTE values.

> The EFs used for HAPs represent the higher of GT or DB emission factors, even though it is unrealistic for a DB to be operational outside of brief summertime events. Thus, the HAP potential emission values are very conservative.

Process ID 1: Steady-State Operation with or without DBs

	Uncontrolled EF		Uncontrolled Emissions		~Control	Controlled Emissions	
	(lb/MMscf)	Basis	(lb/hr)	(tpy)	Efficiency	(lb/hr)	(tpy)
Regulated Pollutants							
NOX	85.406	KU Requirement	337.1	1476.7	90%	33.7	147.7
CO	51.963	KU Requirement	205.1	898.4	90%	20.5	89.8
VOC	3.628	KU Requirement	14.32	62.7	50%	7.16	31.4
PM	5.684	Vendor Estimate	22.4	98.3		22.4	98.3
PM10	5.684	Vendor Estimate	22.4	98.3		22.4	98.3
PM2.5	5.684	Vendor Estimate	22.4	98.3		22.4	98.3
SO2	1.427	Pipeline spec conversion	5.63	24.7		5.63	24.7
H2SO4	0.503	Pipeline spec conversion	1.98	8.7		1.98	8.7
NH3	7.100	KU Requirement	28.0	122.8		28.0	122.8
CO2	123,177	40 CFR 98, Table C-1	486,246	2,129,759		486,246	2,129,759
CH4	8.772	AP-42, Table 3.1-2a	34.6	151.7		34.6	151.7
N2O	3.060	AP-42, Table 3.1-2a	12.1	52.9		12.1	52.9
CO2e	124,308	40 CFR 98 Subpart A	490,712	2,149,318		490,712	2,149,318

		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	0.002	0.008	50%	0.001	0.004
Acetaldehyde	75-07-0	3.59E-01	AP-42 Table 3.1 & 3-4 of BID	1.417	6.208	50%	0.709	3.104
Acrolein	107-02-8	6.53E-03	AP-42 Table 3.1 & 3-4 of BID	0.026	0.113	43%	0.015	0.064
Benzene	71-43-2	1.22E-02	AP-42 Table 3.1 & 3-4 of BID	0.048	0.212	73%	0.013	0.057
Dichlorobenzene	25321-22-6	1.20E-03	AP-42 Table 1.4-3	0.005	0.021	50%	0.002	0.010
Ethylbenzene	100-41-4	3.26E-02	AP-42 Table 3.1	0.129	0.564	50%	0.064	0.282
Formaldehyde	50-00-0	7.24E-01	KU Requirement	2.859	12.522	68%	0.902	3.951
Hexane	110-54-3	1.80E+00	AP-42 Table 1.4-3	7.106	31.122	50%	3.553	15.561
Naphthalene	91-20-3	1.33E-03	AP-42 Table 3.1	0.005	0.023	50%	0.003	0.011
PAH		2.24E-03	AP-42 Table 3.1	0.009	0.039	50%	0.004	0.019
Propylene Oxide	75-56-9	2.96E-02	AP-42 Table 3.1	0.117	0.511	50%	0.058	0.256
Toluene	108-88-3	1.33E-01	AP-42 Table 3.1	0.523	2.29	50%	0.262	1.15
Xylenes	1330-20-7	6.53E-02	AP-42 Table 3.1	0.258	1.13	50%	0.129	0.56
Arsenic	7440-38-2	2.00E-04	AP-42 Table 1.4-4	7.90E-04	3.46E-03	0%	7.90E-04	3.46E-03
Beryllium	7440-41-7	1.20E-05	AP-42 Table 1.4-4	4.74E-05	2.07E-04	0%	4.74E-05	2.07E-04
Cadmium	7440-43-9	1.10E-03	AP-42 Table 1.4-4	4.34E-03	1.90E-02	0%	4.34E-03	1.90E-02
Chromium	7440-47-3	1.40E-03	AP-42 Table 1.4-4	5.53E-03	2.42E-02	0%	5.53E-03	2.42E-02
Cobalt	7440-48-4	8.40E-05	AP-42 Table 1.4-4	3.32E-04	1.45E-03	0%	3.32E-04	1.45E-03
Lead	7439-92-1	5.00E-04	AP-42 Table 1.4-4	1.97E-03	8.65E-03	0%	1.97E-03	8.65E-03
Manganese	7439-96-5	3.80E-04	AP-42 Table 1.4-4	1.50E-03	6.57E-03	0%	1.50E-03	6.57E-03
Mercury	7439-97-6	2.60E-04	AP-42 Table 1.4-4	1.03E-03	4.50E-03	0%	1.03E-03	4.50E-03
Nickel	7440-02-0	2.10E-03	AP-42 Table 1.4-4	8.29E-03	3.63E-02	0%	8.29E-03	3.63E-02
Selenium	7782-49-2	2.40E-05	AP-42 Table 1.4-4	9.47E-05	4.15E-04	0%	9.47E-05	4.15E-04
Total HAP		3.173		12.527	54.868		5.739	25.136

5.5 Capacity and Underlying Assumptions for Cold, Warm, Hot, and Shutdown Events

> The following are estimates provided by each vendor:

			Time in between event and SD
> Cold starts are preceded by over 72 hours of shutdown.			
Maximum Annual Cold Start Events	5 events/yr	40-70 min/C-SU	>72 hr of SD
> Warm start cool down duration ranges from >8 to <72 hours after shutdown. Assume 48 hours.			
Maximum Annual Warm Start Events	45 events/yr	30-60 min/W-SU	8-72 hr of SD
> Hot starts are defined as taking place within 8 hours of the previous shutdown.			
Maximum Annual Hot Start Events	100 events/yr	21-35 min/H-SU	0-8 hr of SD
> 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	150 events/yr	12-21 min/SD	

> There is not an SCC code for turbine SUSD events; therefore, KU used the generic not classified category for industrial processes on an "each" basis.

SCC Code:	39999993	Misc. Industrial Processes (3-99), Others Not Classified (3-99-999-93)
SCC Units:		Each Event (i.e., "lb per event")

5.5.1 Startup and Shutdown Event Emission Factors

> The EFs presented below for emissions of NSR-regulated pollutants from startup and shutdown events are based on the highest vendor-provided 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)
Cold Start	420	758	135	32
Warm Start	260	476	121	27
Hot Start	135	303	91	15
Shutdown	78	244	118	5

5.6 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)	(tpy)	Control Efficiency	Controlled Emissions (lb/yr)	(tpy)
Process ID 2: Cold Startups							
NOX	420	Vendor A Max	2,100	1.05	N/A	2,100	1.05
CO	758	Vendor C Max	3,790	1.90	N/A	3,790	1.90
VOC	135	Vendor B Max	675	0.34	N/A	675	0.34
PM	32	Vendor A Max	160	0.08	N/A	160	0.08
PM10	32	Vendor A Max	160	0.08	N/A	160	0.08
PM2.5	32	Vendor A Max	160	0.08	N/A	160	0.08
Process ID 3: Warm Startups							
NOX	260	Vendor A Max	11,700	5.85	N/A	11,700	5.85
CO	476	Vendor B Max	21,420	10.7	N/A	21,420	10.7
VOC	121	Vendor B Max	5,445	2.72	N/A	5,445	2.72
PM	27	Vendor A Max	1,215	0.61	N/A	1,215	0.61
PM10	27	Vendor A Max	1,215	0.61	N/A	1,215	0.61
PM2.5	27	Vendor A Max	1,215	0.61	N/A	1,215	0.61
Process ID 4: Hot Startups							
NOX	135	Vendor A Max	13,500	6.75	N/A	13,500	6.75
CO	303	Vendor B Max	30,300	15.2	N/A	30,300	15.2
VOC	91	Vendor B Max	9,100	4.55	N/A	9,100	4.55
PM	15	Vendor B Max	1,500	0.75	N/A	1,500	0.75
PM10	15	Vendor B Max	1,500	0.75	N/A	1,500	0.75
PM2.5	15	Vendor B Max	1,500	0.75	N/A	1,500	0.75
Process ID 5: Shutdowns							
NOX	78	Vendor B Max	11,700	5.85	N/A	11,700	5.85
CO	244	Vendor C Max	36,600	18.3	N/A	36,600	18.3
VOC	118	Vendor B Max	17,700	8.9	N/A	17,700	8.85
PM	5	Vendor B Max	750	0.38	N/A	750	0.38
PM10	5	Vendor B Max	750	0.38	N/A	750	0.38
PM2.5	5	Vendor B Max	750	0.38	N/A	750	0.38

5.7 NGCC Overall Combined PTE Summary - Steady State Operations + SUSD Events

> The table below summarizes the PTE from all Process IDs. The total emissions from the NGCC include 8,760 hours at "normal" or steady state operations plus (not minus) the total hours and emissions of events while the GT is emitting.

> The calculation of PTE is conservative since the hours in which SUSD events are occurring are not subtracted from the total steady state operational hours (8,760 hr/yr). In reality, based on the SUSD assumptions, could be as much as 127 hours of SUSD conditions each year.

> Additionally, if the GT/DB experienced all 150 events, there would be no emissions for up to 3,447 hr/yr if one accounted for the downtime in-between SUSD events (i.e., 5 C-SU * 72 avg hrs down + 45 W-SU * 48 avg hrs down + 100 H-SU * 8 avg hrs down).

> Combined Process ID potential emissions are only shown for NOX, CO, VOC, and PM/PM10/PM2.5 since these are the only pollutants for which incremental emissions during SUSD events are quantified. Potential emissions for other pollutants and HAPs are as shown in Section 5.4.

Pollutant	PTE (tpy)
NOX	167.2
CO	135.9
VOC	47.8
PM	100.1
PM10	100.1
PM2.5	100.1

6. Auxiliary Steam Boiler - Emission Calculations

> A new auxiliary steam boiler will be installed as part of the NGCC project. Potential emissions for the auxiliary steam boiler are documented in this section.

6.1 Aux Boiler Nomenclature and Specifications

> Proposed nomenclature for the new Aux Boiler associated with the NGCC Plant:

KyEIS Equipment, Source ID:	**COMB20, 59**
Emission Unit Description:	Auxiliary Steam Boiler
KyEIS Process ID/Description:	1 - Natural Gas Combustion w/ LNB & FGR
Control Device:	--
Stack ID:	S-59

> KU plans to provision a NG-fired auxiliary boiler for the NGCC project. While construction of the GT/DB is targeted to commence in March 2025, because the construction timeline for the Aux Boiler is much shorter, it may not start construction until later in the construction phase. As such, the specific make and model for the Aux Boiler will not be known until farther on in the project development. However, KU plans to procure a boiler with a maximum heat input capacity of 99.9 MMBtu/hr or less and the boiler will be equipped with low-NOX burners with a flue gas recirculation system. For permitting purposes and to calculate potential emissions, this maximum heat input capacity is assumed.

SCC Code	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

> Although the Aux Boiler will only operate periodically to assist with warm or cold startups of the gas turbine (U23) and to provide freeze protection during winter downtime hours, potential emissions are calculated based on 8,760 hr/yr of operation for simplicity and conservatism.

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**99.9**	**MMBtu/hr**	
Gross Steam Generation	82,745	lb/hr	
Net Steam Generation	69,645	lb/hr	
NG Heating Value	1,053	Btu/scf	Average for Brown Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0949	MMscf/hr	99.9 MMBtu/hr / 1,053 MMBtu/MMscf = 0.0949 MMscf/hr
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	

6.2 Derivation and Documentation of Emission Factors

6.2.1 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	%	

6.2.2 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 Low NOx Burners (LNB) and Flue Gas Recirculation (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%)

6.2.3 Regulated NSR Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	0.0364	38.339	KU requirement (Vendor Guarantee) 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	0.0369	38.900	KU requirement (Vendor Guarantee) 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 lb/MMscf
VOC	na	0.0054	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
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
PM/PM10/PM2.5 Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
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	0.109	5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4 1.427 lb SO2/MMscf x 5% x 100% x 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol = 0.109 lb/MMscf
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

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 Aux Boiler Potential Emissions Summary

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	38.339	KU Requirement	3.637	15.93
CO	38.900	KU Requirement	3.690	16.16
VOC	5.5	AP-42 Table 1.4-2	0.522	2.29
PM/PM10/PM2.5-Filt	1.9	AP-42 Table 1.4-2	0.180	0.79
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.149	0.65
PM/PM10/PM2.5 Total	3.47	AP-42 Table 1.4-2	0.329	1.44
SO2	1.43	Pipeline spec conversion	0.135	0.59
H2SO4	0.109	Pipeline spec conversion	0.010	0.05
Lead	0.0005	AP-42, Table 1.4-2	4.74E-05	2.08E-04
CO2	123,177	40 CFR 98, Table C-1	11,686	51,185
CH4	2.3215	40 CFR 98, Table C-2	0.220	0.96
N2O	0.2321	40 CFR 98, Table C-2	0.022	0.10
CO2e	123,304	40 CFR 98, Subpart A	11,698	51,238
Hazardous Air Pollutants	1.888	Sum of HAPs	0.179	0.78
Benzene	2.1E-03	AP-42, Table 1.4-3	1.99E-04	8.73E-04
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.14E-04	4.99E-04
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	7.12E-03	3.12E-02
Hexane	1.800	AP-42, Table 1.4-3	0.171	0.748
Naphthalene	6.1E-04	AP-42, Table 1.4-3	5.79E-05	2.53E-04
Toluene	3.4E-03	AP-42, Table 1.4-3	3.23E-04	1.41E-03
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.90E-05	8.31E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4	1.04E-04	4.57E-04
Chromium	1.4E-03	AP-42, Table 1.4-4	1.33E-04	5.82E-04
Manganese	3.8E-04	AP-42, Table 1.4-4	3.61E-05	1.58E-04
Mercury	2.6E-04	AP-42, Table 1.4-4	2.47E-05	1.08E-04
Nickel	2.1E-03	AP-42, Table 1.4-4	1.99E-04	8.73E-04

Sample Calculations:

NOx (lb/hr) = 38.339 lb/MMscf x 0.0949 MMscf/hr = 3.637 lb/hr NOx

NOx (tpy) = 3.637 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 15.93 tpy NOx

7. Fuel Gas (Dewpoint) Preheater - Emission Calculations

> A new fuel gas preheater will be installed as part of the NGCC project to provide supplemental heating when needed to the incoming natural gas feed stream. Potential emissions for the preheater are documented in this section.

7.1 Preheater Nomenclature and Specifications

> Proposed nomenclature for the new fuel gas (dewpoint) preheater associated with the NGCC Plant:

KyEIS Equipment, Source ID:	**COMB22, 61**
Emission Unit Description:	Fuel Gas (Dewpoint) Preheater
KyEIS Process ID/Description:	1 - NG Fuel Combustion (15 MMBtu/hr)
Control Device:	--
Stack ID:	S-61

> KU plans to provision a natural-gas fired preheater for the NGCC project. The specific make and model are will not be known until farther along in the project development phase. However, the maximum heat input capacity will be 15 MMBtu/hr or less and the preheater will be equipped with LNBs or LNBs with FGR. For permitting purposes and to calculate potential emissions, this maximum heat input capacity is assumed.

SCC Code	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**	**MMBtu/hr**	
NG Heating Value	1,053	Btu/scf	Average for Brown Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0142	MMscf/hr	15 MMBtu/hr / 1,053 MMBtu/MMscf = 0.0142 MMscf/hr
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	

7.2 Derivation and Documentation of Emission Factors

7.2.1 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	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

7.2.2 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	101	118	KU requirement at 100% load at 3% oxygen concentration, corrected to 0% oxygen concentration by multiplying by 20.9% / (20.9% - 3%)

7.2.3 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	0.036	38.339	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	0.075	78.578	KU's Vendor requirement 118 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 = 78.578 lb/MMscf
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
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
PM/PM10/PM2.5 Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
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
H2SO4	7664-93-9	1.04E-04	0.109	5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4 1.427 lb SO2/MMscf x 5% x 100% x 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol = 0.109 lb/MMscf
Lead		4.75E-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	2.32	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

7.2.4 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

7.3 Preheater Potential Emissions Summary

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	38.339	KU Requirement	0.546	2.392
CO	78.578	KU Requirement	1.119	4.903
VOC	5.5	AP-42 Table 1.4-2	0.078	0.343
PM/PM10/PM2.5-Filt	1.9	AP-42 Table 1.4-2	0.027	0.119
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.022	0.098
PM/PM10/PM2.5 Total	3.47	AP-42 Table 1.4-2	0.049	0.217
SO2	1.43	Pipeline spec conversion	0.020	0.089
H2SO4	0.109	Pipeline spec conversion	1.56E-03	6.82E-03
Lead	0.0005	AP-42, Table 1.4-2	7.12E-06	3.12E-05
CO2	123,177	40 CFR 98, Table C-1	1,755	7,685
CH4	2.3215	40 CFR 98, Table C-2	0.033	0.145
N2O	0.2321	40 CFR 98, Table C-2	0.003	0.014
CO2e	123,304	40 CFR 98, Subpart A	1,756	7,693
Hazardous Air Pollutants	1.888	Sum of HAPs	0.027	0.118
Benzene	2.1E-03	AP-42, Table 1.4-3	2.99E-05	1.31E-04
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.71E-05	7.49E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	1.07E-03	4.68E-03
Hexane	1.8E+00	AP-42, Table 1.4-3	2.56E-02	1.12E-01
Naphthalene	6.1E-04	AP-42, Table 1.4-3	8.69E-06	3.81E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	4.84E-05	2.12E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	2.85E-06	1.25E-05
Cadmium	1.1E-03	AP-42, Table 1.4-4	1.57E-05	6.86E-05
Chromium	1.4E-03	AP-42, Table 1.4-4	1.99E-05	8.74E-05
Manganese	3.8E-04	AP-42, Table 1.4-4	5.41E-06	2.37E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	3.70E-06	1.62E-05
Nickel	2.1E-03	AP-42, Table 1.4-4	2.99E-05	1.31E-04

Sample Calculations:

NOx (lb/hr) = 38.339 lb/MMscf x 0.0142 MMscf/hr = 0.546 lb/hr NOx

NOx (tpy) = 0.546 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 2.39 tpy NOx

8. Mechanical Draft Cooling Tower - Emission Calculations

> The NGCC Plant will be served by one re-circulating counterflow wet linear mechanical draft cooling tower. Potential emissions for the cooling tower are documented in this section.

8.1 Cooling Tower Nomenclature and Specifications

> Proposed nomenclature for the new cooling tower associated with the NGCC plant:

KyEIS Equipment, Source ID:	**EQPT21, 62**
Emission Unit Description:	Mechanical Draft Cooling Tower (8 Cells)
KyEIS Process ID/Description:	1 - Gallons of Recirculating Water
Control Device:	--
Stack ID:	S-62

SCC Code	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

8.2 Methodology for Defining Potential PM Emissions from Cooling Tower

8.2.1 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	0.001	%	
Density of Circulating Water	8.34	lb/gal	

PM emission factor based on AP42 13.4 methodology:

PM Factor = 1.0E-05 gal drift/gal flow x 8.34 lb/gal x 990 ppm = 0.0826 lb/MMgal

8.2.2 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.

8.2.3 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

8.3 Cooling Tower Potential Emissions Summary

Pollutant	Emission Factor (lb/MMgal)	Emission Factor 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

9. Diesel-Fired Emergency Generator Engine - Emissions Calculations

> A new diesel-fired emergency generator will be installed as part of the NGCC project to supply power in the event of a power outage. Potential emissions for the emergency generator are documented in this section.

9.1 Emergency Generator Nomenclature and Specifications

> Proposed nomenclature for the new Emergency Generator associated with the NGCC Plant:

KyEIS Equipment, Source ID:	**COMB21, 60**
Emission Unit Description:	2 MW Diesel Emergency Generator
KyEIS Process ID/Description:	1 - Diesel Fuel Combustion
Control Device:	--
Stack ID:	S-60

> KU plans to provision a diesel-fired emergency generator for the NGCC project. The specific make and model will not be known until farther on in the project phase. However, the maximum engine rating will be 2 MW or less. For permitting purposes and to calculate potential emissions, this maximum rating is assumed.

SCC Code	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

Generator Rating	**2,000**	**kW**	Maximum required generator power output
Engine Rating	2,682	bhp	Converted
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
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	0.137	Mgal/hr	= 2,682 bhp x 7,000 Btu/hp-hr / 1E6 Btu/MMBtu / 137.03 MMBtu/Mgal

9.2 Derivation and Documentation of Emission Factors

> While the exact make and model of the emergency engine is not known, it is assumed that the engine will be compliant with the Tier 2 emission standards for generator output greater than 560 kW. Used a manufacturer datasheet for a similarly sized Tier 2 engine provides the emission factors for NO_X, VOC, CO, and $PM/PM_{10}/PM_{2.5}$. Engine will be a CAT 3516C Diesel GenSet with a 3516C, ATAAC, V-16,4-Stroke Water-Cooled Diesel or similar. 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:	6.56	g/hp-hr	Manufacturer Emissions Datasheet
NO_X emission factor in terms of SCC units:	283.110	lb/Mgal	= 6.56 g/hp-hr x 2,682 bhp / 0.137 Mgal/hr / 453.593 gm/lb

VOC

Emission factor for VOC:	0.14	g/hp-hr	Manufacturer Emissions Datasheet
VOC emission factor in terms of SCC units:	6.042	lb/Mgal	= 0.14 g/hp-hr x 2,682 bhp / 0.137 Mgal/hr / 453.593 gm/lb

CO

Emission factor for CO:	0.54 g/hp-hr	Manufacturer Emissions Datasheet
CO emission factor in terms of SCC units:	23.305 lb/Mgal	= 0.54 g/hp-hr x 2,682 bhp / 0.137 Mgal/hr / 453.593 gm/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.04 g/hp-hr	Manufacturer Emissions Datasheet
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	1.726 lb/Mgal	= 0.04 g/hp-hr x 2,682 bhp / 0.137 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	25
N_2O	298

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	74.21	22,420	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

9.2.1 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

9.3 Emergency Generator Potential Emissions Summary

Pollutant	Emission Factor (lb/Mgal)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NOx	283.110	Manufacturer Emissions Datasheet	38.789	9.70
CO	23.305	Manufacturer Emissions Datasheet	3.193	0.80
VOC	6.042	Manufacturer Emissions Datasheet	0.828	0.207
PM/PM10/PM2.5	1.726	Manufacturer Emissions Datasheet	0.237	0.059
SO2	0.208	AP-42 Table 3.4-1	0.028	0.007
CO2	22,343	40 CFR 98, Subpart C, Table C-1	3,061	765.30
CH4	0.906	40 CFR 98, Subpart C, Table C-2	0.124	0.031
N2O	0.181	40 CFR 98, Subpart C, Table C-2	0.025	0.006
CO2e	22,420	40 CFR 98, Subpart A	3,072	767.93
Hazardous Air Pollutants				
Acetaldehyde	0.0035	AP-42 Table 3.4-3	4.73E-04	1.18E-04
Acrolein	0.0011	AP-42 Table 3.4-3	1.48E-04	3.70E-05
Benzene	0.106	AP-42 Table 3.4-3	1.46E-02	3.64E-03
Formaldehyde	0.011	AP-42 Table 3.4-3	1.48E-03	3.70E-04
Naphthalene	0.018	AP-42 Table 3.4-4	2.44E-03	6.10E-04
PAH	0.029	AP-42 Table 3.4-4	3.98E-03	9.95E-04
Toluene	0.039	AP-42 Table 3.4-3	5.28E-03	1.32E-03
Xylenes	0.026	AP-42 Table 3.4-3	3.62E-03	9.06E-04
Total HAP	0.233	AP-42 Table 3.4-3	3.20E-02	8.00E-03

Sample Calculations:
NOx (lb/hr) = 283.110 lb/Mgal x 0.137 Mgal/hr = 38.789 lb/hr NOx
NOx (tpy) = 38.789 lb/hr x 500 hr/yr / 2,000 lb/ton = 9.70 tpy NOx

Example Spec Sheet

Cat® 3516C

Diesel Generator Sets

Image shown may not reflect actual configuration

Bore – mm (in)	170 (6.69)
Stroke – mm (in)	190 (7.48)
Displacement – L (in³)	69 (4210.64)
Compression Ratio	14.7:1
Aspiration	TA
Fuel System	EUI
Governor Type	ADEM™ A3

Standby 60 Hz ekW (kVA)	Mission Critical 60 Hz ekW (kVA)	Prime 60 Hz ekW (kVA)	Continuous 60 Hz ekW (kVA)	Emissions Performance
2000 (2500)	2000 (2500)	1825 (2281)	1650 (2063)	U.S. EPA Stationary Emergency Use Only (Tier 2)

Features

Cat® Diesel Engine
- Meets U.S. EPA Stationary Emergency Use Only (Tier 2) emission standards
- Reliable performance proven in thousands of applications worldwide

Generator Set Package
- Accepts 100% block load in one step and meets NFPA 110 loading requirements
- Conforms to ISO 8528-5 G3 load acceptance requirements
- Reliability verified through torsional vibration, fuel consumption, oil consumption, transient performance, and endurance testing

Alternators
- Superior motor starting capability minimizes need for oversizing generator
- Designed to match performance and output characteristics of Cat diesel engines

Cooling System
- Cooling systems available to operate in ambient temperatures up to 50°C (122°F)
- Tested to ensure proper generator set cooling

EMCP 4 Control Panels
- User-friendly interface and navigation
- Scalable system to meet a wide range of installation requirements
- Expansion modules and site specific programming for specific customer requirements

Warranty
- 24 months/1000-hour warranty for standby and mission critical ratings
- 12 months/unlimited hour warranty for prime and continuous ratings
- Extended service protection is available to provide extended coverage options

Worldwide Product Support
- Cat dealers have over 1,800 dealer branch stores operating in 200 countries
- Your local Cat dealer provides extensive post-sale support, including maintenance and repair agreements

Financing
- Caterpillar offers an array of financial products to help you succeed through financial service excellence
- Options include loans, finance lease, operating lease, working capital, and revolving line of credit
- Contact your local Cat dealer for availability in your region

3516C Diesel Generator Sets
Electric Power

CAT

Package Performance

Performance	Standby		Mission Critical		Prime		Continuous	
Frequency	60 Hz		60 Hz		60 Hz		60 Hz	
Gen set power rating with fan	2000 ekW		2000 ekW		1825 ekW		1650 ekW	
Gen set power rating with fan @ 0.8 power factor	2500 kVA		2500 kVA		2281 kVA		2063 kVA	
Emissions	EPA ESE (TIER 2)		EPA ESE (TIER 2)		EPA ESE (TIER 2)		EPA ESE (TIER 2)	
Performance number	EM1896-03		EM1897-03		DM8264-06		DM8265-05	
Fuel Consumption								
100% load with fan – L/hr (gal/hr)	505.8	(133.6)	505.8	(133.6)	465.6	(123.0)	427.9	(113.0)
75% load with fan – L/hr (gal/hr)	393.9	(104.1)	393.9	(104.1)	366.7	(96.9)	338.3	(89.4)
50% load with fan – L/hr (gal/hr)	284.2	(75.1)	284.2	(75.1)	261.3	(69.0)	238.3	(63.0)
25% load with fan – L/hr (gal/hr)	164.3	(43.4)	164.3	(43.4	154.2	(40.7)	144.1	(38.1)
Cooling System								
Radiator air flow restriction (system) – kPa (in. water)	0.12	(0.48)	0.12	(0.48)	0.12	(0.48)	0.12	(0.48)
Radiator air flow – m³/min (cfm)	2204	(77834)	2204	(77834)	2204	(77834)	2204	(77834)
Engine coolant capacity – L (gal)	233.2	(61.6)	233.2	(61.6)	233.2	(61.6)	233.2	(61.6)
Radiator coolant capacity – L (gal)	180.0	(47.6)	180.0	(47.6)	180.0	(47.6)	180.0	(47.6)
Total coolant capacity – L (gal)	413.2	(109.2)	413.2	(109.2)	413.2	(109.2)	413.2	(109.2)
Inlet Air								
Combustion air inlet flow rate – m³/min (cfm)	185.5	(6548.9)	185.5	(6548.9)	180.0	(6357.6)	174.3	(6155.8)
Exhaust System								
Exhaust stack gas temperature – °C (°F)	400.1	(752.1)	400.1	(752.1)	382.8	(721.1)	370.7	(699.3)
Exhaust gas flow rate – m³/min (cfm)	433.1	(15292.8)	433.1	(15292.8)	408.1	(14410.4)	385.3	(13605.7)
Exhaust system backpressure (maximum allowable) – kPa (in. water)	6.7	(27.0)	6.7	(27.0)	6.7	(27.0)	6.7	(27.0)
Heat Rejection								
Heat rejection to jacket water – kW (Btu/min)	759	(43150)	759	(43150)	715	(40666)	673	(38277)
Heat rejection to exhaust (total) – kW (Btu/min)	1788	(101696)	1788	(101696)	1645	(93554)	1522	(86577)
Heat rejection to aftercooler – kW (Btu/min)	672	(38240)	672	(38240)	612	(34784)	553	(31421)
Heat rejection to atmosphere from engine – kW (Btu/min)	133	(7564)	133	(7564)	127	(7230)	123	(6983)
Heat rejection from alternator – kW (Btu/min)	96	(5464)	96	(5464)	86	(4895)	76	(4326)
Emissions* (Nominal)								
NOx mg/Nm³ (g/hp-h)	2754.3	(5.46)	2754.3	(5.46)	2488.9	(5.05)	2202.3	(4.37)
CO mg/Nm³ (g/hp-h)	143.3	(0.30)	143.3	(0.30)	129.7	(0.27)	112.3	(0.24)
HC mg/Nm³ (g/hp-h)	44.7	(0.11)	44.7	(0.11)	55.6	(0.13)	67.4	(0.16)
PM mg/Nm³ (g/hp-h)	10.4	(0.03)	10.4	(0.03)	10.9	(0.03)	12.0	(0.03)
Emissions* (Potential Site Variation)								
NOx mg/Nm³ (g/hp-h)	3305.2	(6.56)	3305.2	(6.56)	2986.6	(6.06)	2642.7	(5.24)
CO mg/Nm³ (g/hp-h)	258.0	(0.54)	258.0	(0.54)	233.4	(0.49)	202.1	(0.43)
HC mg/Nm³ (g/hp-h)	59.5	(0.14)	59.5	(0.14)	73.9	(0.18)	89.6	(0.22)
PM mg/Nm³ (g/hp-h)	14.6	(0.04)	14.6	(0.04)	15.3	(0.04)	16.8	(0.04)

**mg/Nm³ levels are corrected to 5% O_2. Contact your local Cat dealer for further information.*

10. Diesel-Fired Emergency Fire Pump Engine - Emission Calculations

> A new diesel-fired emergency fire pump engine will be installed as part of the NGCC project to supply water in the event of a fire and/or power outage. Potential emissions for the emergency fire pump engine are documented in this section.

10.1 Emergency Generator Nomenclature and Specifications

> Proposed nomenclature for the new Emergency Fire Pump Engine associated with the NGCC Plant:

KyEIS Equipment, Source ID:	**COMB23, 63**
Emission Unit Description:	400 HP Diesel Driven Fire Pump
KyEIS Process ID/Description:	1 - Diesel Fuel Combustion
Control Device:	--
Stack ID:	S-63

> KU plans to provision a diesel-fired emergency fire pump engine for the NGCC project. The specific make and model will not be known until farther on in the project phase. However, the maximum engine rating will be 400 hp or less For permitting purposes and to calculate potential emissions, this maximum rating is assumed.

SCC Code	20200102
SCC Description	Internal Combustion Engines - Industrial (2-02) - Distillate Oil (Diesel) (2-02-001) - Reciprocating (2-02-001-02)
SCC Units	1000 Gallons Distillate Oil (Diesel) Burned

Engine Rating	**400**	**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	0.020	Mgal/hr	= 400 bhp x 7,000 Btu/hp-hr / 1E6 Btu/MMBtu / 137.03 MMBtu/Mgal

10.2 Derivation and Documentation of Emission Factors

> While the exact make and model of the fire pump engine is not known, it is assumed that the engine will be compliant with the NSPS IIII Table 4 emission standards for engine ratings greater than 300 HP, but less than 600 HP. A manufacturer datasheet for a similarly sized engine provides the emission factors for NOX, VOC, CO, and PM/PM10/PM2.5. 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).

NO_X

Emission factor for NO_X:	2.61	g/hp-hr	Manufacturer Emissions Datasheet
NO_X emission factor in terms of SCC units:	112.640	lb/Mgal	= 2.61 g/hp-hr x 400 bhp / 0.020 Mgal/hr / 453.593 gm/lb

VOC

Emission factor for VOC:	0.10	g/hp-hr	Manufacturer Emissions Datasheet
VOC emission factor in terms of SCC units:	4.316	lb/Mgal	= 0.10 g/hp-hr x 400 bhp / 0.020 Mgal/hr / 453.593 gm/lb

CO

Emission factor for CO:	0.80	g/hp-hr	Manufacturer Emissions Datasheet
CO emission factor in terms of SCC units:	34.526	lb/Mgal	= 0.80 g/hp-hr x 400 bhp / 0.020 Mgal/hr / 453.593 gm/lb

$PM/PM_{10}/PM_{2.5}$

Emission factor for $PM/PM_{10}/PM_{2.5}$:	0.10 g/hp-hr	Manufacturer Emissions Datasheet
$PM/PM_{10}/PM_{2.5}$ emission factor in terms of SCC units:	4.316 lb/Mgal	= 0.10 g/hp-hr x 400 bhp / 0.020 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	25
N_2O	298

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	74.21	22,420	= CO2 EF x CO2 GWP + CH4 EF x CH4 GWP + N2O EF x N2O GWP

10.2.1 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

10.3 Emergency Generator Potential Emissions Summary

Pollutant	Emission Factor (lb/Mgal)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NOx	112.640	Manufacturer Emissions Datasheet	2.302	0.575
CO	34.526	Manufacturer Emissions Datasheet	0.705	0.176
VOC	4.316	Manufacturer Emissions Datasheet	0.088	0.022
PM/PM10/PM2.5	4.316	Manufacturer Emissions Datasheet	0.088	0.022
SO2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %)	0.0042	0.0011
CO2	22,343	40 CFR 98, Subpart C, Table C-1	456.6	114.1
CH4	0.906	40 CFR 98, Subpart C, Table C-2	0.019	0.005
N2O	0.181	40 CFR 98, Subpart C, Table C-2	0.0037	0.0009
CO2e	22,420	40 CFR 98, Subpart A	458.1	114.5
Hazardous Air Pollutants				
1,3-Butadiene	0.0054	AP-42 Table 3.3-2	1.09E-04	2.74E-05
Acetaldehyde	0.105	AP-42 Table 3.3-2	2.15E-03	5.37E-04
Acrolein	0.013	AP-42 Table 3.3-2	2.59E-04	6.48E-05
Benzene	0.128	AP-42 Table 3.3-2	2.61E-03	6.53E-04
Formaldehyde	0.162	AP-42 Table 3.3-2	3.30E-03	8.26E-04
Naphthalene	0.012	AP-42 Table 3.3-2	2.37E-04	5.94E-05
PAH	0.023	AP-42 Table 3.3-2	4.71E-04	1.18E-04
Toluene	0.056	AP-42 Table 3.3-2	1.15E-03	2.86E-04
Xylenes	0.039	AP-42 Table 3.3-2	7.98E-04	2.00E-04
Total HAP	0.542	AP-42 Table 3.3-2	1.11E-02	2.77E-03

Sample Calculations:
NOx (lb/hr) = 112.640 lb/Mgal x 0.020 Mgal/hr = 2.302 lb/hr NOx
NOx (tpy) = 2.302 lb/hr x 500 hr/yr / 2,000 lb/ton = 0.575 tpy NOx

Example Spec Sheet

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.

Emissions Results by Rating run on Apr-05-2022

11. HVAC Heaters - Emissions Calculations

> KU expects to install several HVAC heaters for the new buildings that are associated with the NGCC project to provide heating in winter months as needed. Potential emissions for the HVAC heaters are documented in this section.

11.1 HVAC Heaters Nomenclature and Specifications

> The new HVAC heaters associated with the NGCC Plant will qualify to be classified as insignificant activities under the Title V permit.

Insignificant Activity #:	**IA-43**
Emission Unit Description:	HVAC Heaters (Total <10 MMBtu/hr)

> KU plans to provision multiple natural gas-fired HVAC units within building that support the NGCC project. The specific make and model are TBD. The total combined heat input capacity of all small HVAC heaters is assumed to be 10 MMBtu/hr or less. For permitting purposes and to calculate potential emissions, the maximum combined heat input capacity is assumed.

Max Annual Operating Hours	8,760	hr/yr	
Heat Input Capacity	**10**	**MMBtu/hr**	
NG Heating Value	1,053	Btu/scf	Average for Brown Station Inlet Gas
Max Gas Firing Rate at Average HHV	0.0095	MMscf/hr	10 MMBtu/hr / 1,053 MMBtu/MMscf = 0.0095 MMscf/hr
NG HHV used for AP-42 1.4 Emission Factors	1,020	Btu/scf	

11.2 Derivation and Documentation of Emission Factors

11.2.1 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	%	
Estimated SO_3 to H_2SO_4 Conversion Rate	100	%	

11.2.2 NSR-Regulated Pollutant Emission Factors

Pollutant	CAS #	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
NOx	10102-44-0	0.098	100	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
CO	00630-08-0	0.082	84	AP-42 Section 1.4 Table 1.4-1 for Uncontrolled Small Boilers (7/98)
VOC	na	0.005	5.5	AP-42 Section 1.4 Table 1.4-2 (7/98)
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
PM/PM10/PM2.5 Total		0.0034	3.47	AP-42 Table 1.4-2 + EPA Speciate Database
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
H2SO4	7664-93-9	1.04E-04	0.109	5% conversion of SO2 to SO3 and 100% conversion of SO3 to H2SO4 1.427 lb SO2/MMscf x 5% x 100% x 98.079 lb H2SO4/lbmol / 64.07 lb SO2/lbmol = 0.109 lb/MMscf
Lead		4.75E-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	2.32	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

11.2.3 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

11.3 HVAC Heaters Potential Emissions Summary

Pollutant	Emission Factor (lb/MMscf)	Basis	Potential Emissions (lb/hr)	Potential Emissions (tpy)
NO_X	100	AP-42 Table 1.4-1	0.950	4.160
CO	84	AP-42 Table 1.4-1	0.798	3.494
VOC	5.5	AP-42 Table 1.4-2	0.052	0.229
PM/PM10/PM2.5-Filt	1.9	AP-42 Table 1.4-2	0.018	0.079
PM-Condensable	1.57	AP-42 Table 1.4-2 + EPA Speciate Database	0.015	0.065
PM/PM10/PM2.5 Total	3.47	AP-42 Table 1.4-2	0.033	0.144
SO2	1.43	Pipeline spec conversion	0.014	0.059
H2SO4	0.109	Pipeline spec conversion	1.04E-03	4.54E-03
Lead	0.0005	AP-42, Table 1.4-2	4.75E-06	2.08E-05
CO2	123,177	40 CFR 98, Table C-1	1,170	5,124
CH4	2.3215	40 CFR 98, Table C-2	0.022	0.097
N2O	0.2321	40 CFR 98, Table C-2	0.002	0.010
CO2e	123,304	40 CFR 98, Subpart A	1,171	5,129
Hazardous Air Pollutants	1.888	Sum of HAPs	0.018	0.079
Benzene	2.1E-03	AP-42, Table 1.4-3	1.99E-05	8.74E-05
Dichlorobenzene	1.2E-03	AP-42, Table 1.4-3	1.14E-05	4.99E-05
Formaldehyde	7.5E-02	AP-42, Table 1.4-3	7.12E-04	3.12E-03
Hexane	1.8E+00	AP-42, Table 1.4-3	1.71E-02	7.49E-02
Naphthalene	6.1E-04	AP-42, Table 1.4-3	5.79E-06	2.54E-05
Toluene	3.4E-03	AP-42, Table 1.4-3	3.23E-05	1.41E-04
Arsenic	2.0E-04	AP-42, Table 1.4-4	1.90E-06	8.32E-06
Cadmium	1.1E-03	AP-42, Table 1.4-4	1.04E-05	4.58E-05
Chromium	1.4E-03	AP-42, Table 1.4-4	1.33E-05	5.82E-05
Manganese	3.8E-04	AP-42, Table 1.4-4	3.61E-06	1.58E-05
Mercury	2.6E-04	AP-42, Table 1.4-4	2.47E-06	1.08E-05
Nickel	2.1E-03	AP-42, Table 1.4-4	1.99E-05	8.74E-05

Sample Calculations:

NOx (lb/hr) = 100 lb/MMscf x 0.0095 MMscf/hr = 0.950 lb/hr NOx

NOx (tpy) = 0.950 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 4.160 tpy NOx

12. Lube Oil Demister Vents - Emission Calculations

> KU plans to provision multiple lube oil storage tanks for the NGCC project. The storage tanks will be equipped with demister vents which will be a source of fugitive VOC emissions. Potential VOC emissions from the demister vents are documented in this section.

12.1 Lube Oil Demister Vents Nomenclature and Specifications

> The lube oil tanks and demister vents associated with the NGCC Plant will qualify to be classified as insignificant activities under the Title V permit.

Insignificant Activity #:	**IA-41**
Emission Unit Description:	Lube Oil System with Demister Vents

> The working losses conservatively assume that all lube oil consumed/replaced will evaporate and contribute to VOC emissions. Similar to KU's Cane Run NGCC project, at most 110 and 73 gallons per year of lube oil will be added to the GT and STG, respectively.

Max Annual Operating Hours	8,760	hr/yr	
GT Lube Oil Consumption	0.3	gal/day	Process knowledge
	0.013	gal/hr	Unit Conversion: 0.3 gal/day / 24 hr/day
ST Lube Oil Consumption	0.2	gal/day	Process knowledge
	0.008	gal/hr	Unit Conversion: 0.2 gal/day / 24 hr/day
Total Lube Oil Consumption	**0.021**	**gal/hr**	0.013 gal/day from GT + 0.008 gal/day from ST = 0.021 gal/hr total

12.2 Lube Oil Demister Vents Potential Emissions Summary

	Emission Factor		Potential Emissions	
Pollutant	(lb/gal)	Basis	(lb/hr)	(tpy)
VOC	7.26	Lube oil density	0.151	0.662

Sample Calculations:
VOC (lb/hr) = 7.260 lb/gal x 0.021 gal/hr = 0.151 lb/hr VOC
VOC (tpy) = 0.151 lb/hr x 8,760 hr/yr / 2,000 lb/ton = 0.662 tpy VOC

13. Diesel Storage Tanks for NGCC Units - Emission Calculations

> KU plans to provision diesel storage tanks for the NGCC project to supply fuel to the emergency generator engine and fire pump engine. Potential emissions from the diesel storage tanks are documented in this section.

13.1 Diesel Storage Tanks Nomenclature and Specifications

> 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.

Insignificant Activity #: **IA-42**
Emission Unit Description: Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)

Tank Volume	**4,000**	**gal**	Design specifications
	534.76	ft^3	Unit Conversion: 4000 gal x 7.48 ft3/gal
Tank Diameter	6.98	ft	Design specifications
Tank Height	13.97	ft	Design specifications
Diesel Throughput	68,504	gal/yr	Emergency diesel engine annual fuel consumption (based on 500 hr/yr): 0.137 Mgal/hr x 500 operating hrs/yr x 1000 gal/Mgal
	7.82	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	17.13	turnovers/yr	68,504 gal/yr / 4000 gal = 17.13 turnovers/yr
True Vapor Pressure	0.0064	psia	Calculated by TankESP
Bulk Liquid Storage Temperature	59.00	°F	Calculated by TankESP
Average Liquid Surface Temperature	59.79	°F	Calculated by TankESP

Tank Volume	**440**	**gal**	Design specifications
	58.82	ft^3	Unit Conversion: 440 gal x 7.48 ft3/gal
Tank Diameter	3.35	ft	Design specifications
Tank Height	6.69	ft	Design specifications
Diesel Throughput	10,217	gal/yr	Fire pump diesel engine annual fuel consumption (based on 500 hr/yr): 0.020
	1.17	gal/hr	Assuming continuous operation (i.e., 8,760 hr/yr)
Turnovers	23.22	turnovers/yr	10,217 gal/yr / 440 gal = 23.22 turnovers/yr
True Vapor Pressure	0.0064	psia	Calculated by TankESP
Bulk Liquid Storage	59.00	°F	Calculated by TankESP
Average Liquid Surface	59.79	°F	Calculated by TankESP

13.2 Diesel Storage Tanks Potential Emissions Summary

Storage Tank	Pollutant	Emission Factor (lb/gal)	Basis	Annual Standing Losses (lb/yr)	Annual Working Losses (lb/yr)	Potential Emissions (lb/hr)	Potential Emissions (tpy)
Emergency Generator	VOC	2.89E-05	TankESP analysis using methodology presented in AP-42 Section 7.1	0.605	1.372	2.26E-04	9.89E-04
Fire Pump	VOC	1.81E-06	TankESP analysis using methodology presented in AP-42 Section 7.1	0.067	0.205	3.10E-05	1.36E-04

TankESP: https://www.trinityconsultants.com/software/tanks/tankesp

14. Brown Station Unit 3 Boiler - Emission Reductions from Shutdowns

> The project covered by this permit application encompasses the planned installation of a new NGCC unit in conjunction with the shutdown of the existing Unit 3 coal boiler and its associated upstream and downstream operations.

> The new NGCC unit is targeted to commence operation on April 1, 2028 following a 37-month construction and commissioning phase. Accordingly, the anticipated start of construction for the project is **March 1, 2025**.

> Based on this project schedule, the contemporaneous netting period for the project runs from March 1, 2020 (i.e., 5 years prior to start of construction) up to April 1, 2028 (anticipated date of operation).

> Since the Unit 3 Boiler is completely shutting down as part of the project, its creditable contemporaneous emission decreases will be equivalent to its baseline actual emissions.

> Pursuant to 40 CFR 52.21(b)(48)(i), for any existing electric utility steam generating unit, baseline actual emissions are the average rate in tons per year at which the unit actually emitted a pollutant during any consecutive 24-month period selected by the owner/operator within the 5-year period immediately preceding the time the owner/operator begins actual construction of the project. Thus, for this project, the earliest baseline period available is the 24-month period ending February 2022 (i.e., March 2020 to February 2022).

> A separate 24-month period may be selected for defining baseline actual emissions for each pollutant. The selected baseline period used along with documentation of the baseline actual emissions (and thus the equivalent emission reductions for the project) are provided in the following sub-sections for each relevant regulated NSR polluted emitted by the Unit 3 boiler.

14.1 Unit 3 Boiler Nomenclature

Title V Permit ID:	3
KyEIS Equipment, Source ID:	**COMB3, 003**
Emission Unit Description	Unit 3 Indirect Heat Exchanger
Control Devices	LowNOX; SCR; PJFF; FGD
Control Device IDs:	C03A, B, E, D
Emission Point ID:	17

Process ID	Process Description
1	Coal
2	#2 Fuel Oil

14.2 Unit 3 Boiler: NOX Baseline Actual Emissions

> KU has selected the 24-month period ending June 2022 for defining baseline actual emissions of NOX.

> Because the Unit 3 Boiler is equipped with a NOX CEMS, the baseline actual emissions are known directly from the CEMS data set. The monthly and overall 24-month annual average baseline actual NOX emissions are shown in the table below.

Month	NOX CEMS Emissions (tons)
7/2020	36.0
8/2020	32.3
9/2020	28.0
10/2020	29.2
11/2020	8.0
12/2020	21.1
1/2021	10.1
2/2021	34.2
3/2021	30.4
4/2021	27.1
5/2021	20.8
6/2021	27.8
7/2021	32.0
8/2021	27.3
9/2021	4.3
10/2021	29.2
11/2021	6.7
12/2021	6.1
1/2022	37.3
2/2022	28.7
3/2022	27.5
4/2022	27.2
5/2022	18.1
6/2022	34.4
24-month Total	583.6
Annual Avg	**291.8**

14.3 Unit 3 Boiler: SO2 Baseline Actual Emissions

> KU has selected the 24-month period ending August 2022 for defining baseline actual emissions of SO2.

> Because the Unit 3 Boiler has a SO2 CEMS, the baseline actual emissions are known directly from the CEMS data set. The monthly and overall 24-month annual average baseline actual SO2 emissions are shown in the table below.

Month	SO2 CEMS Emissions (tons)
9/2020	17.5
10/2020	16.1
11/2020	8.2
12/2020	17.5
1/2021	5.7
2/2021	42.1
3/2021	34.9
4/2021	38.6
5/2021	30.8
6/2021	39.6
7/2021	53.3
8/2021	26.5
9/2021	3.2
10/2021	39.7
11/2021	8.6
12/2021	7.7
1/2022	44.6
2/2022	32.5
3/2022	33.6
4/2022	39.6
5/2022	20.3
6/2022	44.6
7/2022	41.8
8/2022	27.0
24-month Total	674.1
Annual Avg	**337.0**

14.4 Unit 3 Boiler: H2SO4 Baseline Actual Emissions

> KU has selected the 24-month period ending February 2022 for defining baseline actual emissions of H2SO4.

> Sulfuric acid mist emissions (H2SO4) are calculated based on the results from annual emission tests conducted in accordance with the Title V permit. Testing is done while firing 100% coal and thus defines the coal combustion emission factor. To accurately estimate the baseline actual emissions, the H2SO4 emission factor used is updated in the months when new testing was completed. Thus, there are three different emission factors used within the 24-month baseline period as listed below.

H2SO4 EF for 3/2020 to 9/2020:	0.0118 lb/MMBtu	Stack test conducted 9/26/2019
H2SO4 EF for 10/2020 to 3/2021:	0.0031 lb/MMBtu	Stack test conducted 10/20/2020
H2SO4 EF for 4/2021 to 2/2022:	0.0016 lb/MMBtu	Stack test conducted 4/19/2021

> Additional H2SO4 emissions associated with combusting fuel oil could be calculated using a reference emission factor in AP-42 Section 1.3 (Fuel Oil Combustion). Specifically, the SO3 emission factor in Table 1.3-1 for No. 2 oil fired in "Boilers > 100 MMBtu/hr" of 5.7S is applicable (where S is the sulfur content of the oil). However, KU combusts ultra low sulfur diesel oil in the Unit 3 Boiler. With a typical sulfur content of 0.0015% for ULSD, the incremental H2SO4 emissions from fuel oil combustion are negligible and thus are not counted for purposes of defining the baseline

> The monthly calculated H2SO4 emissions from the stack test emission factors during the baseline period are tabulated below.

Month	Heat Input from Coal (MMBtu)	H2SO4 Emission Factor (lb/MMBtu)	H2SO4 Emissions (tons)
3/2020	506,832	0.0118	2.99
4/2020	1,372,379	0.0118	8.10
5/2020	1,476,618	0.0118	8.71
6/2020	1,027,139	0.0118	6.06
7/2020	1,631,218	0.0118	9.62
8/2020	1,535,110	0.0118	9.06
9/2020	1,386,254	0.0118	8.18
10/2020	1,180,282	0.0031	1.83
11/2020	370,553	0.0031	0.57
12/2020	561,190	0.0031	0.87
1/2021	231,194	0.0031	0.36
2/2021	1,814,925	0.0031	2.81
3/2021	1,344,704	0.0031	2.08
4/2021	1,290,384	0.0016	1.03
5/2021	983,947	0.0016	0.79
6/2021	1,225,069	0.0016	0.98
7/2021	1,566,542	0.0016	1.25
8/2021	1,173,545	0.0016	0.94
9/2021	148,282	0.0016	0.12
10/2021	1,501,599	0.0016	1.20
11/2021	328,448	0.0016	0.26
12/2021	230,661	0.0016	0.18
1/2022	1,544,138	0.0016	1.24
2/2022	1,096,391	0.0016	0.88
24-month Total			70.1
Annual Avg			**35.1**

<u>Sample Calculations</u>: (for 2/2022)

H2SO4 Emissions = 1,096,391 MMBtu/mo x 0.0016 lb/MMBtu / 2000 lb/ton = 0.88 ton/mo H2SO4

H2SO4 Annual Average Baseline Emissions = 70.1 tons/24-months / 2 years/24-month = 35.1 tpy H2SO4

14.5 Unit 3 Boiler: CO Baseline Actual Emissions

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of CO.

14.5.1 CO Emission Factors

> CO emissions from the Unit 3 Boiler can be attributed to both coal combustion and fuel oil combustion. Total emissions are based on the sum of emissions attributable to each fuel.
> KU has historically calculated actual CO emissions associated with coal combustion in the Unit 3 Boiler for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion), Table 1.1-3, of 0.5 lb/ton.
> Similarly, KU has historically calculated actual CO emissions associated with fuel oil combustion in the Unit 3 Boiler for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.3 (Fuel Oil Combustion), Table 1.3-1, of 5 lb/Mgal.

CO Coal Combustion EF:	0.5 lb/ton	AP-42 1.1 (9/98), Table 1.1-3, for any type of pulverized coal dry bottom furnace
CO Fuel Oil Combustion EF:	5 lb/Mgal	AP-42 1.3, Table 1.3-1, for boilers > 100 MMBtu/yr

> The monthly coal and fuel oil usage rates during the selected baseline period for Unit 3 along with the calculated CO baseline emissions using the factors cited are shown in the following table.

Month	Coal Usage (tons)	CO Emissions from Coal (tons)	Fuel Oil Usage (Mgal)	CO Emissions from Oil (tons)	Total CO Monthly Emissions (tons)
4/2020	57,837	14.46	24.007	0.060	14.52
5/2020	61,318	15.33	0.000	0.000	15.33
6/2020	43,058	10.76	0.000	0.000	10.76
7/2020	68,391	17.10	22.945	0.057	17.16
8/2020	63,243	15.81	3.277	0.008	15.82
9/2020	56,611	14.15	0.078	0.000	14.15
10/2020	49,257	12.31	21.192	0.053	12.37
11/2020	15,776	3.94	3.297	0.008	3.95
12/2020	24,104	6.03	88.343	0.221	6.25
1/2021	10,368	2.59	20.469	0.051	2.64
2/2021	71,162	17.79	0.000	0.000	17.79
3/2021	56,775	14.19	12.846	0.032	14.23
4/2021	54,275	13.57	17.611	0.044	13.61
5/2021	41,003	10.25	24.660	0.062	10.31
6/2021	51,744	12.94	35.963	0.090	13.03
7/2021	66,378	16.59	0.651	0.002	16.60
8/2021	49,460	12.37	40.245	0.101	12.47
9/2021	6,327	1.58	22.286	0.056	1.64
10/2021	63,581	15.90	0.000	0.000	15.90
11/2021	14,281	3.57	1.534	0.004	3.57
12/2021	10,049	2.51	28.090	0.070	2.58
1/2022	70,482	17.62	27.292	0.068	17.69
2/2022	48,607	12.15	31.075	0.078	12.23
3/2022	47,946	11.99	0.331	0.001	11.99
24-month Total	1,102,033	275.5	426.2	1.065	276.6
Annual Avg	551,017	137.8	213.1	0.533	**138.3**

<u>Sample Calculations</u>: (for 3/2022)
CO Emissions from Coal = 47,946 tons coal/mo x 0.5 lb/ton / 2000 lb/ton = 11.99 tons CO/mo
CO Emissions from Fuel Oil = 0.331 Mgal/mo x 5 lb/Mgal / 2000 lb/ton = 0.001 tons CO/mo
Total CO Monthly Emissions = 11.99 + 0.001 = 11.99 tons CO/mo
Annual Average Baseline Emissions = 276.6 tons/24-months / 2 years/24-month = 138.3 tpy CO

14.6 Unit 3 Boiler: VOC Baseline Actual Emissions

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of VOC.

14.6.1 VOC Emission Factors

> VOC emissions from the Unit 3 Boiler can be attributed to both coal combustion and fuel oil combustion. Total emissions are based on the sum of emissions attributable to each fuel.

> KU has historically calculated actual VOC emissions associated with coal combustion in the Unit 3 Boiler for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion), Table 1.1-19, of 0.06 lb/ton.

> Similarly, KU has historically calculated actual VOC emissions associated with fuel oil combustion in the Unit 3 Boiler for annual emission inventory purposes using the reference emission factor in AP-42 Section 1.3 (Fuel Oil Combustion), Table 1.3-3, of 0.2 lb/Mgal.

VOC Coal Combustion EF:	0.06 lb/ton	AP-42 1.1 (9/98), Table 1.1-19, TNMOC for pulverized coal dry bottom furnaces
VOC Fuel Oil Combustion EF:	0.2 lb/Mgal	AP-42 1.3, Table 1.3-3, NMTOC factor for distillate oil fired in industrial boilers

> The monthly coal and fuel oil usage rates during the selected baseline period for Unit 3 along with the calculated VOC baseline emissions using the factors cited are shown in the following table.

Month	Coal Usage (tons)	VOC Emissions from Coal (tons)	Fuel Oil Usage (Mgal)	VOC Emissions from NG (tons)	Total VOC Monthly Emissions (tons)
4/2020	57,837	1.74	24.007	0.0024	1.74
5/2020	61,318	1.84	0.000	0.0000	1.84
6/2020	43,058	1.29	0.000	0.0000	1.29
7/2020	68,391	2.05	22.945	0.0023	2.05
8/2020	63,243	1.90	3.277	0.0003	1.90
9/2020	56,611	1.70	0.078	0.0000	1.70
10/2020	49,257	1.48	21.192	0.0021	1.48
11/2020	15,776	0.47	3.297	0.0003	0.47
12/2020	24,104	0.72	88.343	0.0088	0.73
1/2021	10,368	0.31	20.469	0.0020	0.31
2/2021	71,162	2.13	0.000	0.0000	2.13
3/2021	56,775	1.70	12.846	0.0013	1.70
4/2021	54,275	1.63	17.611	0.0018	1.63
5/2021	41,003	1.23	24.660	0.0025	1.23
6/2021	51,744	1.55	35.963	0.0036	1.56
7/2021	66,378	1.99	0.651	0.0001	1.99
8/2021	49,460	1.48	40.245	0.0040	1.49
9/2021	6,327	0.19	22.286	0.0022	0.19
10/2021	63,581	1.91	0.000	0.0000	1.91
11/2021	14,281	0.43	1.534	0.0002	0.43
12/2021	10,049	0.30	28.090	0.0028	0.30
1/2022	70,482	2.11	27.292	0.0027	2.12
2/2022	48,607	1.46	31.075	0.0031	1.46
3/2022	47,946	1.44	0.331	0.0000	1.44
24-month Total	1,102,033	33.1	426.2	0.0426	33.1
Annual Avg	551,017	16.5	213.1	0.0213	**16.6**

Sample Calculations: (for 2/2022)
VOC Emissions from Coal = 48,607 tons coal/mo x 0.06 lb/ton / 2000 lb/ton = 1.46 tons VOC/mo
VOC Emissions from Fuel Oil = 31.075 Mgal/mo x 0.2 lb/Mgal / 2000 lb/ton = 0.0031 tons VOC/mo
Total VOC Monthly Emissions = 1.46 + 0.0031 = 1.46 tons VOC/mo
Annual Average Baseline Emissions = 33.1 tons/24-months / 2 years/24-month = 16.6 tpy VOC

14.7 Unit 3 Boiler: PM/PM10/PM2.5 Baseline Actual Emissions

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of PM, PM10, and PM2.5.

14.7.1 Coal Combustion PM Emission Factors

> KU conducts annual emission tests for filterable PM from the Unit 3 Boiler as required by the Title V permit. The emission factor from each year's test is used to calculate actual PM filterable emissions. To accurately estimate the baseline actual emissions, the PM emission factor used is updated in the months when new testing was completed. Thus, there are three different emission factors used within the 24-month baseline period as listed below.

> Note that for annually KyEIS emission inventories, the emission factors from the annual tests (lb/MMBtu) are converted to equivalent lb/ton emission factors based on that year's average coal heating value since the SCC code used has units of tons of coal burned. However, for these baseline actual emission calculations the emission are based directly on the test-derived emission factor (lb/MMBtu) and the actual monthly heat input in Unit 3 from coal to more accurately tally the monthly emission rates used in the 24-month baseline period. Mathematically, the annual emissions are roughly equivalent.

Coal Combustion Emission Factors

PM Filterable EF for 4/2020 to 9/2020:	0.018 lb/MMBtu	Annual PM emission test conducted 9/25/2019
PM Filterable EF for 10/2020 to 3/2021:	0.010 lb/MMBtu	Annual PM emission test conducted 10/20/2020
PM Filterable EF for 4/2021 to 3/2022:	0.0057 lb/MMBtu	Annual PM emission test conducted 4/27/2021

> KU has historically calculated actual PM10 and PM2.5 emissions from coal combustion for annual emission inventory purposes using the cumulative particle size distribution information for coal boilers in AP-42 Section 1.1 (Bituminous and Subbituminous Coal Combustion), Table 1.1-6.

> Specifically, as shown in AP-42 Table 1.1-6, for a baghouse controlled coal boiler, 92% of cumulative PM filterable mass can be expected to be PM10 and 53% of the cumulative PM filterable mass can be expected to be PM2.5.

> Condensable PM emissions from coal combustion are estimated based on the emission factor in AP-42 Section 1.1, Table 1.1-5, for "pulverized coal boilers with PM control combined with FGD control" of 0.02 lb/MMBtu.

PM10/PM Filterable Size Ratio:	0.92	AP-42 1.1 (9/98), Table 1-1-6, Cumulative Mass % for baghouse controlled boiler
PM2.5/PM Filterable Size Ratio:	0.53	AP-42 1.1 (9/98), Table 1-1-6, Cumulative Mass % for baghouse controlled boiler
PM Condensable EF for Coal:	0.020 lb/MMBtu	AP-42 1.1 (9/98), Table 1-1-5, Coal boiler with PM controls combined with FGD

14.7.2 Fuel Oil Combustion PM Emission Factors

> Filterable PM emissions attributable to fuel oil combustion are estimated based on the emission factor in AP-42 Section 1.3, Table 1.3-1 for No. 2 oil fired in "Boilers > 100 MMBtu/hr" of 2 lb/Mgal. In the KyEIS, KU his historically used the same emission factor for filterable PM10 and PM2.5, consistent with the information on cumulative size distribution in AP-42 Table 1.3-4 for scrubber controlled utility boilers.

> Condensable PM emissions from fuel oil combustion are estimated based on the emission factor in AP-42 Section 1.3, Table 1.3-2 for No. 2 oil fired boilers of 1.3 lb/Mgal.

> Although condensable PM emissions are not tracked in the annual KyEIS inventory for the Unit 3 Boiler, they are included her for purposes of defining baseline actual emissions since PSD applicability is based on total PM (filterable + condensable).

PM/PM10/PM2.5 EF for Oil:	2 lb/Mgal	AP-42 1.3 (5/10), Table 1.3-1, "Boilers > 100 MMBtu/hr", No. 2 oil fired
PM Condensable EF for Oil:	1.3 lb/Mgal	AP-42 1.3 (5/10), Table 1.3-2, No. 2 oil fired CPM-TOT

14.7.3 Unit 3 Baseline Actual PM/PM10/PM2.5 Emissions from Coal

> The monthly heat input from coal during the selected baseline period along with the calculated filterable, condensable, and total PM, PM10, and PM2.5 emissions attributable to coal combustion are shown in the following table.

Month	Coal Heat Input (MMBtu)	PM Filterable Emissions from Coal (tons)	PM10 Filterable Emissions from Coal (tons)	PM2.5 Filterable Emissions from Coal (tons)	Condens. PM Emissions from Coal (tons)	Total PM Emissions from Coal (tons)	Total PM10 Emissions from Coal (tons)	Total PM2.5 Emissions from Coal (tons)
4/2020	1,372,379	12.35	11.36	6.55	13.72	26.08	25.09	20.27
5/2020	1,476,618	13.29	12.23	7.04	14.77	28.06	26.99	21.81
6/2020	1,027,139	9.24	8.50	4.90	10.27	19.52	18.78	15.17
7/2020	1,631,218	14.68	13.51	7.78	16.31	30.99	29.82	24.09
8/2020	1,535,110	13.82	12.71	7.32	15.35	29.17	28.06	22.67
9/2020	1,386,254	12.48	11.48	6.61	13.86	26.34	25.34	20.47
10/2020	1,180,282	5.90	5.43	3.13	11.80	17.70	17.23	14.93
11/2020	370,553	1.85	1.70	0.98	3.71	5.56	5.41	4.69
12/2020	561,190	2.81	2.58	1.49	5.61	8.42	8.19	7.10
1/2021	231,194	1.16	1.06	0.61	2.31	3.47	3.38	2.92
2/2021	1,814,925	9.07	8.35	4.81	18.15	27.22	26.50	22.96
3/2021	1,344,704	6.72	6.19	3.56	13.45	20.17	19.63	17.01
4/2021	1,290,384	3.68	3.38	1.95	12.90	16.58	16.29	14.85
5/2021	983,947	2.80	2.58	1.49	9.84	12.64	12.42	11.33
6/2021	1,225,069	3.49	3.21	1.85	12.25	15.74	15.46	14.10
7/2021	1,566,542	4.46	4.11	2.37	15.67	20.13	19.77	18.03
8/2021	1,173,545	3.34	3.08	1.77	11.74	15.08	14.81	13.51
9/2021	148,282	0.42	0.39	0.22	1.48	1.91	1.87	1.71
10/2021	1,501,599	4.28	3.94	2.27	15.02	19.30	18.95	17.28
11/2021	328,448	0.94	0.86	0.50	3.28	4.22	4.15	3.78
12/2021	230,661	0.66	0.60	0.35	2.31	2.96	2.91	2.66
1/2022	1,544,138	4.40	4.05	2.33	15.44	19.84	19.49	17.77
2/2022	1,096,391	3.12	2.87	1.66	10.96	14.09	13.84	12.62
3/2022	1,116,501	3.18	2.93	1.69	11.17	14.35	14.09	12.85
24-month Total	26,137,074	138.16	127.11	73.22	261.37	399.53	388.48	334.59
Annual Avg	13,068,537	69.08	63.55	36.61	130.69	199.76	194.24	167.30

<u>Sample Calculations</u>: (for 3/2022)
PM-Filterable Emissions = 1,116,501 MMBtu/mo x 0.0057 lb/MMBtu / 2000 lb/ton = 3.18 tons/mo PM-Filterable
PM10-Filterable Emissions = 3.18 tons PM-Filt/mo x 0.92 = 2.93 tons/mo PM10-Filterable
PM2.5-Filterable Emissions = 3.18 tons PM-Filt/mo x 0.53 = 1.69 tons/mo PM2.5-Filterable
Condensible PM Emissions = 1,116,501 MMBtu/mo x 0.02 lb/MMBtu / 2000 lb/ton = 11.17 tons/mo PM Condensible
Total PM Emissions = 3.18 tons PM-Filt/mo + 11.17 tons PM-Cond/mo = 14.35 tons/mo PM

14.7.4 Unit 3 Baseline Actual PM/PM10/PM2.5 Emissions from Fuel Oil

> The monthly fuel oil usage during the selected baseline period along with the calculated filterable, condensable, and total PM, PM10, and PM2.5 emissions attributable to fuel oil combustion are shown in the following table.

Month	Fuel Oil Usage (Mgal)	PM Filterable Emissions from Oil (tons)	Condens. PM Emissions from Oil (tons)	Total PM Emissions from Oil (tons)	Total PM10 Emissions from Oil (tons)	Total PM2.5 Emissions from Oil (tons)
4/2020	24.0	0.0240	0.0156	0.0396	0.0396	0.0396
5/2020	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
6/2020	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
7/2020	22.9	0.0229	0.0149	0.0379	0.0379	0.0379
8/2020	3.3	0.0033	0.0021	0.0054	0.0054	0.0054
9/2020	0.1	0.0001	0.0001	0.0001	0.0001	0.0001
10/2020	21.2	0.0212	0.0138	0.0350	0.0350	0.0350
11/2020	3.3	0.0033	0.0021	0.0054	0.0054	0.0054
12/2020	88.3	0.0883	0.0574	0.1458	0.1458	0.1458
1/2021	20.5	0.0205	0.0133	0.0338	0.0338	0.0338
2/2021	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
3/2021	12.8	0.0128	0.0083	0.0212	0.0212	0.0212
4/2021	17.6	0.0176	0.0114	0.0291	0.0291	0.0291
5/2021	24.7	0.0247	0.0160	0.0407	0.0407	0.0407
6/2021	36.0	0.0360	0.0234	0.0593	0.0593	0.0593
7/2021	0.7	0.0007	0.0004	0.0011	0.0011	0.0011
8/2021	40.2	0.0402	0.0262	0.0664	0.0664	0.0664
9/2021	22.3	0.0223	0.0145	0.0368	0.0368	0.0368
10/2021	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
11/2021	1.5	0.0015	0.0010	0.0025	0.0025	0.0025
12/2021	28.1	0.0281	0.0183	0.0463	0.0463	0.0463
1/2022	27.3	0.0273	0.0177	0.0450	0.0450	0.0450
2/2022	31.1	0.0311	0.0202	0.0513	0.0513	0.0513
3/2022	0.3	0.0003	0.0002	0.0005	0.0005	0.0005
24-month Total	426	0.43	0.28	0.70	0.70	0.70
Annual Avg	213	0.21	0.14	0.35	0.35	0.35

Sample Calculations: (for 3/2022)
PM-Filterable Emissions = 0.3 Mgal/mo x 2 lb/Mgal / 2000 lb/ton = 0.0003 tons/mo PM-Filterable
Condensible PM Emissions = 0.3 Mgal/mo x 1.3 lb/gal / 2000 lb/ton = 0.0002 tons/mo PM Condensible
Total PM Emissions = 0.0003 tons PM-Filt/mo + 0.0002 tons PM-Cond/mo = 0.0005 tons/mo PM

14.7.5 Unit 3 Baseline Actual PM/PM10/PM2.5 Emissions Total from Coal and Fuel Oil Combined

> Based on the separately tallied PM emissions from coal and fuel oil for each month in the selected baseline period, the total combined PM emissions are shown in the following table.

Month	Total PM Emissions (Coal+Oil) (tons)	Total PM10 Emissions (Coal+Oil) (tons)	Total PM2.5 Emissions (Coal+Oil) (tons)
4/2020	26.11	25.13	20.31
5/2020	28.06	26.99	21.81
6/2020	19.52	18.78	15.17
7/2020	31.03	29.86	24.13
8/2020	29.17	28.07	22.68
9/2020	26.34	25.34	20.48
10/2020	17.74	17.27	14.97
11/2020	5.56	5.42	4.69
12/2020	8.56	8.34	7.24
1/2021	3.50	3.41	2.96
2/2021	27.22	26.50	22.96
3/2021	20.19	19.65	17.03
4/2021	16.61	16.32	14.88
5/2021	12.68	12.46	11.37
6/2021	15.80	15.52	14.16
7/2021	20.13	19.77	18.03
8/2021	15.15	14.88	13.57
9/2021	1.94	1.91	1.74
10/2021	19.30	18.95	17.28
11/2021	4.22	4.15	3.78
12/2021	3.01	2.96	2.70
1/2022	19.89	19.54	17.82
2/2022	14.14	13.89	12.67
3/2022	14.35	14.09	12.85
24-month Total	400.23	389.18	335.30
Annual Avg	**200.1**	**194.6**	**167.6**

<u>Sample Calculations</u>: (for 3/2022)

Combined PM10 Total Emissions = 14.09 tons/mo from Coal + 0.0005 tons/mo from Oil = 14.09 tons/mo Total PM10

Annual Average Baseline PM10 Emissions = 389.18 tons/24-months / 2 years/24-month = 194.59 tpy Total PM10

14.8 Lead Baseline Actual Emissions

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of lead.

14.8.1 Lead Emission Factors

> For annual emission inventory purposes, uncontrolled lead emissions from coal combustion for the Unit 3 boiler have historically calculated based on the methodology specified in AP-42 Section 1.1, Table 1.1-16. Emissions under this methodology are calculated as a function of coal concentration, ash content, and the PM emission factor.

> The current emission factor in the KyEIS was previously documented in the July 2009 Title V permit renewal application based on nominal average coal properties at that time. Based on a 13.8% coal ash content, the uncontrolled PM emission factor in AP-42 Table 1.1-4 is 138 lb/ton, or 6.273 lb/MMBtu based on a nominal coal heating value of 22 MMBtu/ton.

> The AP-42 Table 1.1-16 emission factor equation for lead is 3.4*(C/A*PM)^0.8, where PM is the uncontrolled PM emission rate. Based on a nominal coal lead concentration of 10 ppmwt, the uncontrolled lead emission factor calculates to 454.407 lb/TBtu [i.e., 3.4*(10/0.138*6.273)^0.8], or 0.01 lb/ton at a nominal coal heating value of 22 MMBtu/ton. Using the same Table 1.1-16 equation with a controlled PM emission factor of 0.03 lb/MMBtu, the estimated controlled lead emission rate if 6.238 lb/TBtu, or 1.39E-4 lb/ton. This is equivalent to a control efficiency for lead of 98.6%, which is the value currently in the KyEIS for Unit 3.

> The amount of lead emissions attributable to fuel oil combustion are negligible and thus have not been quantified for the purposes of defining baseline actual emissions.

Lead EF for Coal (Uncontrolled):	0.01 lb/ton	AP-42 Table 1.1-16 methodology based on coal ash and lead content
KyEIS Control Efficiency	98.61%	Estimated based on controlled lead EF from AP-42 Table 1.1-16 methodology
Lead EF for Coal (Controlled):	1.39E-04 lb/ton	0.01 lb/ton x (1-0.9861) = 1.39E-04 lb/ton

> The monthly coal usage during the selected baseline period for the Unit 3 boiler and calculated baseline emissions for lead are shown in the following table.

Month	Coal Usage (tons)	Lead Emissions (tons)
4/2020	57,837	0.0040
5/2020	61,318	0.0043
6/2020	43,058	0.0030
7/2020	68,391	0.0048
8/2020	63,243	0.0044
9/2020	56,611	0.0039
10/2020	49,257	0.0034
11/2020	15,776	0.0011
12/2020	24,104	0.0017
1/2021	10,368	0.0007
2/2021	71,162	0.0050
3/2021	56,775	0.0040
4/2021	54,275	0.0038
5/2021	41,003	0.0029
6/2021	51,744	0.0036
7/2021	66,378	0.0046
8/2021	49,460	0.0034
9/2021	6,327	0.0004
10/2021	63,581	0.0044
11/2021	14,281	0.0010
12/2021	10,049	0.0007
1/2022	70,482	0.0049
2/2022	48,607	0.0034
3/2022	47,946	0.0033
24-month Total	1,102,033	0.077
Annual Avg	551,017	**0.038**

Sample Calculations: (for 3/2022)
Lead Emissions = 47,946 tons/mo x 1.39E-04 lb/ton / 2000 lb/ton = 0.0033 ton/mo lead
Annual Average Baseline Emissions = 0.077 tons/24-months / 2 years/24-month = 0.038 tpy lead

14.9 Unit 3 Boiler: CO2e Baseline Actual Emissions

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of CO2e.

14.9.1 GHG Emission Factors

> Because the Unit 3 Boiler has a CO2 CEMS, the baseline actual emissions for CO2 are known directly from the CEMS data set. The monthly and overall 24-month annual average baseline actual CO2 emissions are shown in the table below.

> Emission factors for methane and nitrous oxide from both coal and fuel oil combustion are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Table C-2).

> The global warming multiplying factors for CH4 and N2O are those specified in 40 CFR 98, Subpart A.

Coal CH4 Emission Factor:	1.10E-02	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Fuel Oil CH4 Emission Factor:	3.00E-03	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Coal N2O Emission Factor:	1.60E-03	kg/MMBtu	40 CFR 98 Subpart C, Table C-2
Fuel Oil N2O Emission Factor:	6.00E-04	kg/MMBtu	40 CFR 98 Subpart C, Table C-2

Global warming multiplying factors to calculate CO2e emissions:

GWP for CO2:	1	40 CFR 98 Subpart A, Table A-1
GWP for CH4:	25	40 CFR 98 Subpart A, Table A-1
GWP for N2O:	298	40 CFR 98 Subpart A, Table A-1

> The monthly coal and oil heat input rates during the selected baseline period for Unit 3 are shown in the following table. The baseline actual CO_2e emissions are calculated based on the directly measured CO_2 emissions and the calculated CH_4 and N_2O emissions as shown.

Month	Measured CO2 CEMS Emissions (tons)	Coal Heat Input (MMBtu)	Fuel Oil Heat Input (MMBtu)	CH4 Emissions (tons)	N2O Emissions (tons)	CO2e Emissions (tons)
4/2020	141,146	1,375,692	3,361	16.7	2.4	142,287
5/2020	151,502	1,476,618	0	17.9	2.6	152,725
6/2020	105,384	1,027,139	0	12.5	1.8	106,235
7/2020	167,687	1,634,384	3,212	19.8	2.9	169,043
8/2020	157,549	1,535,562	459	18.6	2.7	158,821
9/2020	142,230	1,386,265	11	16.8	2.4	143,378
10/2020	121,398	1,183,207	2,967	14.4	2.1	122,379
11/2020	38,066	371,008	461	4.5	0.7	38,374
12/2020	58,829	573,382	12,368	7.0	1.0	59,308
1/2021	24,010	234,019	2,866	2.8	0.4	24,205
2/2021	165,691	1,814,925	0	22.0	3.2	167,195
3/2021	138,149	1,346,477	2,588	16.3	2.4	139,265
4/2021	132,642	1,292,815	2,365	15.7	2.3	133,714
5/2021	101,303	987,350	3,452	12.0	1.7	102,122
6/2021	126,201	1,230,032	5,035	14.9	2.2	127,222
7/2021	160,737	1,566,632	91	19.0	2.8	162,036
8/2021	120,975	1,179,099	5,634	14.3	2.1	121,954
9/2021	15,529	151,357	3,120	1.8	0.3	15,655
10/2021	154,064	1,501,599	0	18.2	2.6	155,308
11/2021	33,720	328,659	215	4.0	0.6	33,993
12/2021	24,064	234,538	3,933	2.9	0.4	24,259
1/2022	158,815	1,547,904	3,821	18.8	2.7	160,099
2/2022	112,928	1,100,680	4,351	13.4	1.9	113,842
3/2022	114,558	1,116,547	46	13.5	2.0	115,483
24-month Total	2,667,176	26,195,888	60,356	317.8	46.2	2,688,901
Annual Avg	1,333,588	13,097,944	30,178	158.9	23.1	**1,344,451**

Sample Calculations: (for 1/2022)
CH_4 Emissions = 1,547,904 MMBtu/mo x 1.10E-02 kg/MMBtu x 2.20462 lb/kg / 2000 lb/ton + 3,821 MMBtu/mo x 3.00E-03 kg/MMBtu x 2.20462 lb/kg / 2000 lb/ton = 18.8 tons/mo CH_4

N_2O Emissions = 1,547,904 MMBtu/mo x 1.60E-03 kg/MMBtu x 2.20462 lb/kg / 2000 lb/ton + 3,821 MMBtu/mo x 6.00E-04 kg/MMBtu x 2.20462 lb/kg / 2000 lb/ton = 2.7 tons/mo N_2O

CO_2e Emissions = 158,815 tons/mo CO_2 + (18.8 tons/mo CH_4 x 25) + (2.7 tons/mo N_2O x 298) = 160,099 tons/mo CO_2e
Annual Average Baseline Emissions = 2,688,901 tons/24-months / 2 years/24-month = 1,344,451 tpy CO_2e

15. Coal Handling Operations - Emission Reductions from Shutdowns

> In conjunction with the new NGCC project, all coal handling operations at Brown Station will cease operation with the permanent shutdown of the Unit 3 Boiler, which will result in PM/PM10/PM2.5 emission reductions that are documented in this section.

> The coal handling operations associated with the Unit 3 Boiler being shutdown are covered by Emission Units 7, 9, 13, and 16 in the Title V permit.

15.1 PM/PM10/PM2.5 Emission Factors Used for Baseline Actual Emissions Calculations

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of PM, PM10, and PM2.5.

15.1.1 PM Emission Factors from Hopper and Conveyor Transfers

> KU has historically calculated actual PM, PM10 and PM2.5 emissions for the coal handling operations for annual emission inventory purposes using emission factors originally published by the Midwest Research Institute (MRI). These same emission factors, which have been used since the original Title V permit action for KyEIS purposes are also being used to document baseline actual emissions.

> One set of emission factors is used for transfers to coal receiving hoppers and another set is used for belt conveyor transfers. For these activities, PM10 is assumed to equal PM and PM2.5 has historically been set to 20% of PM/PM10. The same 90% control efficiency that has been historically applied to account for the enclosure of the transfer points is retained for the baseline actual emission calculations.

> For the tripper conveyor transfers, which occur inside the building and are controlled by small filter systems, a different set of MRI emission factors have historically been used for emission inventory purposes. Due to the use of a filter system, a higher control efficiency of 99.5% has historically been applied and PM2.5 is assumed to equal 80% of PM.

	PM EF (lb/ton)	PM10 EF (lb/ton)	PM2.5 EF (lb/ton)	Control Efficiency (%)	Basis
Receiving Hoppers (07-1 and 09-1)	0.0004	0.0004	0.00008	90%	MRI; Historical KyEIS
Conveyor Transfer Points	0.0003	0.0003	0.00006	90%	MRI; Historical KyEIS
Tripper Conveyor Transfers (13-2 and 13-3)	0.007	0.007	0.0056	99.5%	MRI; Historical KyEIS

15.1.2 PM Emission Factors from Coal Stockpile Operations

> PM emissions from the coal stockpile have historically been calculated taking into account emissions occurring through two mechanisms- (1) transfers of coal to the pile and (2) wind erosion. PM emissions are relatively low due to the natural characteristics of coal received at the plant, as well as additional measures employed, such as compaction and wet suppression.

Transfers to Coal Stockpile

> PM emission factors for transfers to the coal stockpile are calculated using Equation 1 from AP-42 Section 13.2.4, Aggregate Handling and Storage Piles. The mean wind speed used in this equation is based on historical from Lexington. The material moisture content used is based on AP-42 Table 13.2.4-1, which lists the mean value for coal at a coal-fired power plant at 4.5%. The uncontrolled emission factors are reduced by 70% due to the presence of dust suppression measures.

E (lb/ton) = 0.0032*k* * (*U* /5)^1.3 / (*M* /2)^1.4   where:

	PM	PM10	PM2.5
k: Particle Size Multiplier (lb/VMT)	0.74	0.35	0.053
M Material Moisture Content (%)	4.5	4.5	4.5
U Mean Wind Speed (mph)	8.4	8.4	8.4
E: Emission Factor (lb/ton)	1.49E-03	7.06E-04	1.07E-04

<u>Sample Calculation</u>: (for PM for Outdoor Transfer)
PM Outdoor Transfer EF = 0.0032 x 0.74 x (8.4 /5)^1.3 / (4.5 /2)^1.4 = 1.49E-03 lb/ton

Wind Erosion from Coal Stockpile

> Fugitive PM emissions can result from wind erosion of the coal storage pile when gusts of wind cause loose dust on the surface of the pile to become airborne. The annual quantity of emissions is dependent on the silt content of the coal stored, the moisture of the pile (predicted by the number of days per year with measurable precipitation), and the percentage of hours per year that the wind speed exceeds the threshold speed of 12 miles per hour. Emissions are calculated on a pounds per day per acre basis using the method from the EPA Document "Control of Open Fugitive Dust Sources".

> Emission rates are converted to mass per time unit (lb/hr) based on the maximum estimated surface area of the coal pile. The emission rate is then divided by the coal processing rate of the overall coal handling system to derive the emission factor used for baseline actual emission calculations.

Control of Open Fugitive Dust Sources; EPA-450/3-88-008, September 1988, Page 4-17, Equation 2:
E (lb/day/acre) = 1.7 * (*s*/1.5) * (365-*p*)/235 * *f*/15

where:

s	Silt content (%)	2.2	%	Silt content of coal from AP-42 Table 13.2.4-1.
p	Number of days with >0.01 in precipitation pe	130	days	AP-42 Figure 13.2.1-2.
f	% of time unobstructed wind speed > 12 mph	12		Lexington NWS surface data
E	PM/PM10 Emission Factor (lb/day/acre)	1.99	lb/day/acre	

Sample Calculation:
PM/PM10 Emission Factor = 1.7 x (2.2/1.5) x (365 - 130)/235 x 12/15 = 1.99 lb/day/acre

> Based on the dimensions of the coal storage area, the surface area of the coal pile is approximately 6 acres.

Coal surface area:	6	acre	
PM Emission Factor (lb/hr) (average)	0.50	lb/hr	6 acre x 1.99 lb/day/acre / 24 hr/day = 0.50 lb/hr
Coal handling area process rate:	1,640	ton/hr	As noted in V-17-030 R1
Wind Erosion PM Emission Factor (lb/ton)	3.04E-04	lb/ton	0.50 lb/hr / 1,640 ton/hr = 3.04E-04 lb/ton
Wind Erosion PM10 Emission Factor (lb/ton)	1.52E-04	lb/ton	Historically assumed to be 50% of PM
Wind Erosion PM2.5 Emission Factor (lb/hr)	6.08E-05	lb/ton	Historically assumed to be 20% of PM

Combined Coal Stockpile Emission Factor

	PM	PM10	PM2.5
Transfers to Coal Stockpile - Emission Factors (lb/ton)	1.49E-03	7.06E-04	1.07E-04
Wind Erosion from Coal Stockpile - Emission Factors (lb/ton)	3.04E-04	1.52E-04	6.08E-05
TOTAL (Uncontrolled, lb/ton)	**0.0018**	**0.00086**	**0.00017**
Control efficiency applied for dust suppression measures	70%	70%	70%
TOTAL (Controlled, lb/ton)	5.39E-04	2.58E-04	5.10E-05

15.1.3 PM Emission Factors from Coal Crusher

> KU has historically calculated actual PM, PM10 and PM2.5 emissions from the coal crusher operations for annual emission inventory purposes using emission factors originally published by the Midwest Research Institute (MRI). These same emission factors, which have been used since the original Title V permit action for KyEIS purposes are also being used to document baseline actual emissions.

> The coal crushers are controlled by a wet scrubber system. The same 99% control efficiency that has been historically applied is retained for the baseline actual emission calculations.

	PM EF (lb/ton)	PM10 EF (lb/ton)	PM2.5 EF (lb/ton)	Control Efficiency (%)	Basis
Coal Crusher (Routed to Wet Scrubber)	0.02	0.01	0.002	99%	MRI; Historical KyEIS

15.2 Coal Usage Associated with Brown Unit 3 Boiler During Baseline Period

> The monthly coal usage rates for the Unit 3 Boiler operations during the selected baseline period are shown in the following table.

Month	Brown Unit 3 Coal Usage (tons)
4/2020	57,837
5/2020	61,318
6/2020	43,058
7/2020	68,391
8/2020	63,243
9/2020	56,611
10/2020	49,257
11/2020	15,776
12/2020	24,104
1/2021	10,368
2/2021	71,162
3/2021	56,775
4/2021	54,275
5/2021	41,003
6/2021	51,744
7/2021	66,378
8/2021	49,460
9/2021	6,327
10/2021	63,581
11/2021	14,281
12/2021	10,049
1/2022	70,482
2/2022	48,607
3/2022	47,946
24-month Total	1,102,033
Annual Avg	551,017

15.3 Coal Handling Operations Baseline Actual PM/PM10/PM2.5 Emissions

> The baseline actual PM/PM10/PM2.5 emissions are calculated based on the 24-month annual average coal usage in the baseline period and the PM, PM10, and PM2.5 emission factors as shown in the tables below.

> Note that the conveyor transfer points with Emission Units 9-1 to 9-5 and 13-1 served the Unit 1 and 2 Boilers, which were shutdown in 2019. As there was no coal throughput/usage for the Units 1 and 2 Boilers in the selected baseline period, these emission units do not contribute to the baseline actual emissions total.

15.3.1 Baseline Actual Emissions - PM

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Coal Usage in Baseline Period (tpy)	PM Emission Factor (lb/ton)	Control Efficiency (%)	PM Filterable Emissions (tpy)
Coal Handling Operations 07							
7-1	EQPT14, 07	1	West Track Hopper	551,017	0.0004	90%	0.0110
7-2	EQPT14, 07	2	Conveyor A-1	551,017	0.0003	90%	0.0083
7-3	EQPT14, 07	3	Conveyor E	551,017	0.0003	90%	0.0083
7-4	EQPT14, 07	4	Conveyor F	551,017	0.0003	90%	0.0083
7-5	EQPT14, 07	5	Conveyor G	551,017	0.0003	90%	0.0083
7-6	EQPT14, 07	6	Conveyor H	551,017	0.0003	90%	0.0083
Subtotal							**0.0523**
Coal Handling Operations 09							
9-1	EQPT15, 09	1	East Track Hopper	--	--	--	--
9-2	EQPT15, 09	2	Conveyor A	--	--	--	--
9-3	EQPT15, 09	3	Conveyor B	--	--	--	--
9-4	EQPT15, 09	4	Conveyor C	--	--	--	--
9-5	EQPT15, 09	5	Conveyor J	--	--	--	--
9-6	EQPT15, 09	6	Coal Stockpile	551,017	0.0018	70%	0.1486
Subtotal							**0.1486**
Coal Handling Operations 13							
13-1	EQPT16, 13	1	Conveyor D [Tripper for Units 1 & 2]	--	--	--	--
13-2	EQPT16, 13	2	Conveyor K-1 [Upper Tripper for Unit 3]	551,017	0.007	99.5%	0.0096
13-3	EQPT16, 13	3	Conveyor K [Lower Tripper for Unit 3]	551,017	0.007	99.5%	0.0096
Subtotal							**0.0193**
Coal Crushing							
16	EQPT1, 16	1	Four Crushers and Crusher House	551,017	0.02	99%	0.0551
Total Baseline Emissions for PM							**0.2753**

Sample Calculations: (for EU 7-1)
PM Emissions = 551,017 tpy of coal x 0.0004 lb/ton x (1-0.9) / 2000 lb/ton = 0.0110 tpy PM

15.3.2 Baseline Actual Emissions - PM10

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Coal Usage in Baseline Period (tpy)	PM10 Emission Factor (lb/ton)	Control Efficiency (%)	PM10 Filterable Emissions (tpy)
Coal Handling Operations 07							
7-1	EQPT14, 07	1	West Track Hopper	551,017	0.0004	90%	0.0110
7-2	EQPT14, 07	2	Conveyor A-1	551,017	0.0003	90%	0.0083
7-3	EQPT14, 07	3	Conveyor E	551,017	0.0003	90%	0.0083
7-4	EQPT14, 07	4	Conveyor F	551,017	0.0003	90%	0.0083
7-5	EQPT14, 07	5	Conveyor G	551,017	0.0003	90%	0.0083
7-6	EQPT14, 07	6	Conveyor H	551,017	0.0003	90%	0.0083
Subtotal							**0.0523**
Coal Handling Operations 09							
9-1	EQPT15, 09	1	East Track Hopper	--	--	--	--
9-2	EQPT15, 09	2	Conveyor A	--	--	--	--
9-3	EQPT15, 09	3	Conveyor B	--	--	--	--
9-4	EQPT15, 09	4	Conveyor C	--	--	--	--
9-5	EQPT15, 09	5	Conveyor J	--	--	--	--
9-6	EQPT15, 09	6	Coal Stockpile	551,017	0.00086	70%	0.0711
Subtotal							**0.0711**
Coal Handling Operations 13							
13-1	EQPT16, 13	1	Conveyor D [Tripper for Units 1 & 2]	--	--	--	--
13-2	EQPT16, 13	2	Conveyor K-1 [Upper Tripper for Unit 3]	551,017	0.007	99.5%	0.0096
13-3	EQPT16, 13	3	Conveyor K [Lower Tripper for Unit 3]	551,017	0.007	99.5%	0.0096
Subtotal							**0.0193**
Coal Crushing							
16	EQPT1, 16	1	Four Crushers and Crusher House	551,017	0.01	99%	0.0276
Total Baseline Emissions for PM							**0.1703**

<u>Sample Calculations: (for EU 7-1)</u>
PM10 Emissions = 551,017 tpy of coal x 0.0004 lb/ton x (1-0.9) / 2000 lb/ton = 0.0110 tpy PM10

15.3.3 Baseline Actual Emissions - PM2.5

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Coal Usage in Baseline Period (tpy)	PM2.5 Emission Factor (lb/ton)	Control Efficiency (%)	PM2.5 Filterable Emissions (tpy)
Coal Handling Operations 07							
7-1	EQPT14, 07	1	West Track Hopper	551,017	0.00008	90%	0.0022
7-2	EQPT14, 07	2	Conveyor A-1	551,017	0.00006	90%	0.0017
7-3	EQPT14, 07	3	Conveyor E	551,017	0.00006	90%	0.0017
7-4	EQPT14, 07	4	Conveyor F	551,017	0.00006	90%	0.0017
7-5	EQPT14, 07	5	Conveyor G	551,017	0.00006	90%	0.0017
7-6	EQPT14, 07	6	Conveyor H	551,017	0.00006	90%	0.0017
Subtotal							**0.0105**
Coal Handling Operations 09							
9-1	EQPT15, 09	1	East Track Hopper	--	--	--	--
9-2	EQPT15, 09	2	Conveyor A	--	--	--	--
9-3	EQPT15, 09	3	Conveyor B	--	--	--	--
9-4	EQPT15, 09	4	Conveyor C	--	--	--	--
9-5	EQPT15, 09	5	Conveyor J	--	--	--	--
9-6	EQPT15, 09	6	Coal Stockpile	551,017	0.00017	70%	0.0141
Subtotal							**0.0141**
Coal Handling Operations 13							
13-1	EQPT16, 13	1	Conveyor D [Tripper for Units 1 & 2]	--	--	--	--
13-2	EQPT16, 13	2	Conveyor K-1 [Upper Tripper for Unit 3]	551,017	0.0056	99.5%	0.0077
13-3	EQPT16, 13	3	Conveyor K [Lower Tripper for Unit 3]	551,017	0.0056	99.5%	0.0077
Subtotal							**0.0154**
Coal Crushing							
16	EQPT1, 16	1	Four Crushers and Crusher House	551,017	0.002	99%	0.0055
Total Baseline Emissions for PM							**0.0455**

Sample Calculations: (for EU 7-1)
PM10 Emissions = 551,017 tpy of coal x 0.0001 lb/ton x (1-0.9) / 2000 lb/ton = 0.0022 tpy PM10

16. Limestone Handling Operations - Emission Reductions from Shutdowns

> In conjunction with the permanent shutdown of the Unit 3 Boiler and its associated flue-gas desulfurization (FGD) system, all the limestone receiving, handling, and processing operations at Brown Station will also shut down, which will result in PM/PM10/PM2.5 emission reductions that are documented in this section.

> The limestone handling system serving the FGD system at Brown Station consists of a truck unloading station, limestone conveying and storage, and limestone processing system. Once limestone is conveyed into the processing building, the milling of limestone occurs using a wet process. Therefore, the only emission sources associated with the limestone system are those upstream of the processing building.

16.1 PM/PM10/PM2.5 Emission Factors Used for Baseline Actual Emissions Calculations

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of PM, PM10, and PM2.5.

> PM that may be generated at the limestone transfer points are each captured and controlled in a fabric filter system. PM potential emissions have historically been estimated for emission inventory purposes using emission factors derived from filter vendor design specifications, or, for those systems for which site-specific performance testing has been conducted, the results of the performance tests. These same emission factors are also being used to document baseline actual emissions.

> For the Limestone Truck Dump Stations, the PM emission factor is derived from a 0.0044 gr/dscf (10 mg/m3) design specification. Based on the design flowrate and maximum process rate, the PM emission factor is 0.067 lb/ton, as shown in the current KyEIS. PM2.5 emissions from the limestone handling operations have historically been set at 20% of PM for emission inventory purposes.

> The PM emission factors for the Limestone Stacking Tube and Reclaim Conveyors are taken from the results of performance tests conducted January 13-14, 2011. However, because the KyEIS embeds a presumed control efficiency of 98% for the filter systems, the uncontrolled emission factor is back-calculated from the test results assuming 98% control.

> The PM emission factors for the Limestone Stacking Tube and Reclaim Conveyors are taken directly from the results of performance tests conducted January 13-14, 2011.

Emission Unit	PM/PM10 (lb/ton)	PM2.5 (lb/ton)	Control Efficiency (%)	Basis
Limestone Truck Dump Station Transfers	0.067	0.013	98%	Filter design specification (0.0044 gr/dscf)
Limestone Stacking Tube	0.00107	0.00107	98%	Jan 2011 Test (0.00014 lb/ton controlled)
Limestone Reclaim Conveyor Transfers	0.007	0.007	98%	Jan 2011 Test (2.1402E-05 lb/ton controlled)

16.2 Limestone Process Rates Associated with Brown Unit 3 Boiler FGD During Baseline Period

> The monthly limestone processed for the Unit 3 Boiler FGD operations during the selected baseline period are shown in the following table.

Month	FGD System Limestone Process Rate (tons)
4/2020	6,082
5/2020	5,921
6/2020	4,619
7/2020	6,608
8/2020	6,241
9/2020	6,046
10/2020	5,194
11/2020	1,392
12/2020	2,549
1/2021	1,124
2/2021	7,633
3/2021	5,230
4/2021	5,620
5/2021	3,628
6/2021	4,817
7/2021	7,372
8/2021	4,941
9/2021	831
10/2021	5,676
11/2021	1,298
12/2021	984
1/2022	7,020
2/2022	4,135
3/2022	4,321
24-month Total	109,282
Annual Avg	54,641

16.3 Limestone Handling Operations Baseline Actual PM/PM10/PM2.5 Emissions

> The baseline actual PM/PM10/PM2.5 emissions are calculated based on the 24-month annual average limestone process rate in the baseline period and the PM, PM10, and PM2.5 emission factors as shown in the tables below.

16.3.1 Baseline Actual Emissions - PM and PM10

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Limestone in Baseline Period (tpy)	Emission Factor (lb/ton)	Control Efficiency (%)	Emissions (tpy)
PM/PM10 Filterable							
30	EQPT17, 30-31	1	Limestone Truck Dump Station #1	54,641	0.067	98%	0.0366
31	EQPT17, 30-31	2	Limestone Truck Dump Station #2	54,641	0.067	98%	0.0366
Subtotal for EU 30-31							**0.0732**
32	EQPT18, 32-34	1	Limestone Stacking Tube	54,641	0.00107	98%	0.0006
33-34	EQPT18, 32-34	2	Limestone Reclaim Conveyor #1 & 2	54,641	0.007	98%	0.0038
Subtotal for EU 32-34							**0.0044**
Combined Total for EU 30-34							**0.0776**

Sample Calculations: (for EU 30)

PM Emissions = 54,641 tpy of limestone x 0.0670 lb/ton x (1-0.98) / 2000 lb/ton = 0.0366 tpy PM

16.3.2 Baseline Actual Emissions - PM2.5

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	Limestone in Baseline Period (tpy)	Emission Factor (lb/ton)	Control Efficiency (%)	Emissions (tpy)
30	EQPT17, 30-31	1	Limestone Truck Dump Station #1	54,641	0.013	98%	0.0071
31	EQPT17, 30-31	2	Limestone Truck Dump Station #2	54,641	0.013	98%	0.0071
Subtotal for EU 30-31							**0.0142**
32	EQPT18, 32-34	1	Limestone Stacking Tube	54,641	0.00107	98%	0.0006
33-34	EQPT18, 32-34	2	Limestone Reclaim Conveyor #1 & 2	54,641	0.007	98%	0.0038
Subtotal for EU 32-34							**0.0044**
Combined Total for EU 30-34							**0.0186**

Sample Calculations: (for EU 30)

PM Emissions = 54,641 tpy of limestone 0.0130 lb/ton x (1-0.98) / 2000 lb/ton = 0.0071 tpy PM

17. Unit 3 Cooling Tower - Emission Reductions from Shutdowns

> In conjunction with the permanent shutdown of the Unit 3 Boiler the Unit 3 Cooling Tower will also shut down, which will result in PM/PM10/PM2.5 emission reductions that are documented in this section.

17.1 Unit 3 Cooling Tower Nomenclature

Title V Permit ID:	38
KyEIS Equipment, Source ID:	**EQPT19, 36-38**
Emission Unit Description	Cooling Tower 3 (Forced Draft)
Control Devices	Drift Eliminators

17.2 PM/PM10/PM2.5 Emission Factors Used for Baseline Actual Emissions Calculations

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of PM, PM10, and PM2.5.

> Particulate matter emissions result from the operation of cooling towers due to the presence of dissolved solids in the cooling tower water that is released through the cooling tower vent fans. As the cooling tower water moves through the air away from the vent fans, the liquid water evaporates, leaving behind solid particles in the form of particulate matter. Particulate matter emissions from cooling towers have historically been calculated for emission inventory purposes using the procedures of AP-42 Section 13.4, 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 water.

> The TDS content of the cooling tower water is calculated by multiplying the nominal make-up water TDS content by the cooling tower "cycles of concentration", as noted in AP-42 Section 13.4 (1/1995). "Cycles of concentration" is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter in the make-up water.

> The design specifications for the drift eliminators on the Unit 3 Cooling Tower is a drift loss of 0.005%.

> An EPA Technical Report (600/7-79-251a, Nov 1979) noted that of the total amount of water emitted from a cooling tower vent, only 31.3% remains airborne a short distance from the vent. Therefore, the total liquid drift loss mass has historically been adjusted by this value.

> Based on the nature and origin of the particulate matter emitted from cooling towers, all PM is assumed to be PM2.5.

Nominal TDS in make-up water:	303	ppm	
Cycles of Concentration:	1.7		
TDS in Recirculation Water:	515.1	ppm	303 ppm x 1.7 = 515.1 ppm
Drift Loss Specification:	0.00005	gal drift/gal flow	
Drift mass governed by atmospheric dispersion:	31.3%		
PM emission factor:	0.067	lb/MMgal	

0.00005 gal/gal x 0.313 x 8.34 lb/gal x 515.1 lb/10^6 lb = 0.067 lb/10^6 gal

17.3 Unit 3 Cooling Tower Baseline Actual PM/PM10/PM2.5 Emissions

> The monthly water throughput in the Unit 3 Cooling Tower during the selected baseline period and the calculated PM/PM10/PM2.5 baseline emissions calculated using the documented emission factors are shown in the following table.

Month	Cooling Tower Process Rate (MMgal)	PM/PM10/ PM2.5 Factor (lb/MMgal)	PM/PM10 PM2.5 Emissions (tons)
4/2020	6,715	0.067	0.225
5/2020	7,715	0.067	0.258
6/2020	4,942	0.067	0.166
7/2020	7,516	0.067	0.252
8/2020	7,715	0.067	0.258
9/2020	7,466	0.067	0.250
10/2020	6,039	0.067	0.202
11/2020	1,847	0.067	0.062
12/2020	274	0.067	0.009
1/2021	1,005	0.067	0.034
2/2021	6,969	0.067	0.233
3/2021	7,204	0.067	0.241
4/2021	6,321	0.067	0.212
5/2021	4,950	0.067	0.166
6/2021	5,700	0.067	0.191
7/2021	7,549	0.067	0.253
8/2021	5,968	0.067	0.200
9/2021	705	0.067	0.024
10/2021	7,715	0.067	0.258
11/2021	1,369	0.067	0.046
12/2021	1,049	0.067	0.035
1/2022	5,838	0.067	0.196
2/2022	5,222	0.067	0.175
3/2022	5,734	0.067	0.192
24-month Total	123,527		4.14
Annual Avg	61,763		**2.07**

Sample Calculations: (for 12/2021)

PM/PM10/PM2.5 Emissions = 1,049 MMgal/mo x 0.067 lb/MMgal / 2000 lb/ton = 0.035 ton/mo

Annual Average Baseline PM Emissions = 4.14 tons/24-months / 2 years/24-month = 2.07 tpy

18. CCR Landfill Operations and Haul Trucks - Emission Reductions from Shutdowns

> In conjunction with the permanent shutdown of the Unit 3 Boiler, which is the last of the coal-fired boilers in operation at Brown Station, all transport of bottom ash, flyash, and gypsum to the landfill will cease, which will result in PM/PM10/PM2.5 emission reductions that are documented in this section.

18.1 PM/PM10/PM2.5 Emission Factors Used for Baseline Actual Emissions Calculations

> KU has selected the 24-month period ending March 2022 for defining baseline actual emissions of PM, PM10, and PM2.5.

> PM emissions due to truck travel on plant roads to and from the CCR Landfill have historically been estimated using methodologies of AP-42 Section 13.2.1 for paved roads and AP-42 Section 13.2.2 for unpaved roads. These emission factors are tied to the total vehicle miles traveled with full and empty trucks. A control efficiency is also applied to the derived AP-42 emission factors to account for dust suppression activities employed to mitigate fugitive dust from the haul roads. These same emission factors and control efficiencies, consistent with those used for the 2020-2022 KyEIS annual emission inventories, are used to define baseline actual emissions.

	PM (lb/VMT)	PM10 (lb/VMT)	PM2.5 (lb/VMT)	Control Efficiency
Paved Routes - Empty Trucks	0.129	0.026	0.006	70%
Paved Routes - Full Trucks	0.157	0.031	0.008	70%
Unpaved Routes - Empty Trucks	1.103	0.270	0.027	70%
Unpaved Routes - Full Trucks	1.745	0.427	0.043	70%
Heavy Equipment Travel In/Around Landfill	1.285	0.314	0.031	70%

18.2 Vehicle Miles Traveled Associated with Each Landfill Material Transport Activity

> The monthly vehicle miles traveled values for each of the defined landfill transport haul truck routes during the selected baseline period are shown in

Month	Bottom Ash Trucks (VMT)	Fly Ash Trucks (VMT)	Gypsum Trucks (VMT)
4/2020	16.8	155.7	334.5
5/2020	20.2	188.2	331.4
6/2020	19.0	142.8	257.7
7/2020	21.3	202.2	362.9
8/2020	16.8	176.4	352.2
9/2020	19.0	188.2	304.9
10/2020	17.4	118.2	277.8
11/2020	5.0	70.0	131.0
12/2020	0.0	51.5	97.0
1/2021	6.7	12.9	20.8
2/2021	21.3	220.6	371.1
3/2021	11.8	184.2	324.5
4/2021	14.0	177.5	292.3
5/2021	15.7	127.1	226.2
6/2021	19.0	165.8	253.3
7/2021	17.9	203.3	357.2
8/2021	10.1	160.2	269.6
9/2021	7.8	19.0	57.3
10/2021	24.1	145.0	413.9
11/2021	9.0	85.7	109.0
12/2021	1.1	11.8	24.6
1/2022	24.1	202.7	351.5
2/2022	30.8	154.6	300.5
3/2022	18.5	201.6	275.9
24-mo Total	367.4	3,365.0	6,097.1
Annual Avg	183.7	1,682.5	3,048.6

18.3 CCR Landfill Operations Baseline Actual PM/PM10/PM2.5 Emissions

> The baseline actual PM/PM10/PM2.5 emissions are calculated based on the 24-month annual average VMT values and the PM, PM10, and PM2.5 emission factors as shown in the tables below.

> The total CCR Landfill emissions from truck load trips is based on the sum of emissions from the portion of the truck route VMTs on paved roads and the portion of the truck route VMTs on unpaved roads. However, the paved portion is relatively small and the emission factors are very small relative to the unpaved factors. To be conservative with respect to setting baseline actual emissions to calculate emission reductions, only the emissions associated with the unpaved truck route VMTs has been tabulated.

18.3.1 Baseline Actual Emissions - PM

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	VMT in Baseline Period (VMT)	PM Emission Factor (lb/VMT)	Control Efficiency (%)	PM Filterable Emissions (tpy)
50	AREA4, EU 50	7	Unpaved Empty Bottom Ash Transport	183.7	1.103	70%	0.030
50	AREA4, EU 50	8	Unpaved Full Bottom Ash Transport	183.7	1.745	70%	0.048
50	AREA4, EU 50	9	Unpaved Empty Fly Ash Transport	1,682.5	1.103	70%	0.278
50	AREA4, EU 50	10	Unpaved Full Fly Ash Transport	1,682.5	1.745	70%	0.440
50	AREA4, EU 50	11	Unpaved Empty Gypsum Transport	3,048.6	1.103	70%	0.504
50	AREA4, EU 50	12	Unpaved Full Gypsum Transport	3,048.6	1.745	70%	0.798
Total Baseline Emissions for PM							**2.100**

Sample Calculations: (for EU 50, Process ID 12)
PM Emissions = 3,048.6 VMT x 1.7450 lb/VMT x (1-0.7) / 2000 lb/ton = 0.798 tpy PM

18.3.2 Baseline Actual Emissions - PM10

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	VMT in Baseline Period (VMT)	PM10 Emission Factor (lb/VMT)	Control Efficiency (%)	PM10 Filterable Emissions (tpy)
50	AREA4, EU 50	7	Unpaved Empty Bottom Ash Transport	184	0.270	70%	0.007
50	AREA4, EU 50	8	Unpaved Full Bottom Ash Transport	184	0.427	70%	0.012
50	AREA4, EU 50	9	Unpaved Empty Fly Ash Transport	1,683	0.270	70%	0.068
50	AREA4, EU 50	10	Unpaved Full Fly Ash Transport	1,683	0.427	70%	0.108
50	AREA4, EU 50	11	Unpaved Empty Gypsum Transport	3,049	0.270	70%	0.123
50	AREA4, EU 50	12	Unpaved Full Gypsum Transport	3,049	0.427	70%	0.195
Total Baseline Emissions for PM							**0.514**

Sample Calculations: (for EU 50, Process ID 12)
PM Emissions = 3,048.6 VMT x 0.4270 lb/VMT x (1-0.7) / 2000 lb/ton = 0.195 tpy PM

18.3.3 Baseline Actual Emissions - PM2.5

Title V EU ID	KyEIS Equipment, Source ID	KyEIS Process ID	Process Description	VMT in Baseline Period (VMT)	PM2.5 Emission Factor (lb/VMT)	Control Efficiency (%)	PM2.5 Filterable Emissions (tpy)
50	AREA4, EU 50	7	Unpaved Empty Bottom Ash Transport	184	0.027	70%	0.001
50	AREA4, EU 50	8	Unpaved Full Bottom Ash Transport	184	0.043	70%	0.001
50	AREA4, EU 50	9	Unpaved Empty Fly Ash Transport	1,683	0.027	70%	0.007
50	AREA4, EU 50	10	Unpaved Full Fly Ash Transport	1,683	0.043	70%	0.011
50	AREA4, EU 50	11	Unpaved Empty Gypsum Transport	3,049	0.027	70%	0.012
50	AREA4, EU 50	12	Unpaved Full Gypsum Transport	3,049	0.043	70%	0.020
Total Baseline Emissions for PM							**0.052**

Sample Calculations: (for EU 50, Process ID 12)
PM Emissions = 3,048.6 VMT x 0.0430 lb/VMT x (1-0.7) / 2000 lb/ton = 0.020 tpy PM

APPENDIX C. AIR PERMIT APPLICATION FORMS

The following 7007 Series air permit application forms are included with this permit application:

1. DEP7007AI – Administrative Information
2. DEP7007A – Indirect Heat Exchangers and Turbines
3. DEP7007B – Manufacturing or Processing Operations
4. DEP7007N – Source Emissions Profile
5. DEP7007V – Applicable Requirements and Compliance Activities
6. DEP700DD – Insignificant Activities
7. DEP7007EE – Internal Combustion Engines
8. DEP7007GG – Control Equipment

The Acid Rain Program revision application covering the NGCC Project is also provided in this appendix following the application forms.

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: 12/13/2022

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. The new project covered by this application covers the installation of a new NGCC power block and associated support operations.

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)* 3/1/2025

Proposed Operation Start-Up Date: *(MM/YYYY)* 4/1/2028

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.

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
- [ ] 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
- [ ] DEP7007CC Compliance Certification See CY2021 ACC
- [x] DEP7007DD Insignificant Activities
- [x] DEP7007EE Internal Combustion Engines
- [ ] DEP7007FF Secondary Aluminum Processing
- [x] DEP7007GG Control Equipment
- [ ] 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...

Steven B. Turner	12/15/2022 | 8:18 AM EST
Authorized Signature	**Date**
Steven Turner	Vice President, Power Production
Type or Printed Name of Signatory	**Title of Signatory**

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

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

Imber

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: 12/13/2022

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	1	Natural Gas Firing in GT & DB	Gas Turbine and HRSG with Duct Burner	na	GE 7HA.03, Mitsubishi 501JAC, Siemens 9000HL, or Similar		03/2025	20100201	MMcf	C34, C35	58
		2	Cold Startup Events						39999993	Event	na	58
		3	Warm Startup Events						39999993	Event	na	58
		4	Hot Startup Events						39999993	Event	na	58
		5	Shutdown Events						39999993	Event	na	58
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	Indirect Heat Exchanger	Boiler	Generic, < 99.99 MMBtu/hr		03/2025	10200602	MMcf	na	59
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	Indirect Heat Exchanger	Process Heater	Generic, <= 15 MMBtu/hr		03/2025	39990003	MMcf	na	61

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	4,157	664	MW Net	Refer to Section 6 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	99.9	na	na	na	Primary	Natural Gas	1,053	Btu/scf	8,760	na	0.5 gr/Ccf
COMB22, 61	0	100	0	na	15	na	na	na	Primary	Natural Gas	1,053	Btu/scf	8,760	na	0.5 gr/Ccf

Section A.3: Notes, Comments, and Explanations
Refer to Sections 4 and 5 in Appendix B of the application for an explanation of the base load operating scenario as well as startup/shutdown events.

Division for Air Quality

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DEP7007B

Manufacturing or Processing Operations

___ Section B.1: Process Information
___ Section B.2: Materials and Fuel Information
___ 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: December 13, 2022

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 *(MM/YYYY)*	Is the Process Continuous or Batch?	Number of Batches per 24 Hours *(if applicable)*	Hours per Batch *(if applicable)*
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)		1	Gallons of Recirculating Water	na	na	03/2025	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, 62	Mechanical Draft Cooling Tower (8 Cells)	Cooling Water	5.70	MMgal/hr	na	na	na	na	na	na	na	na	na	na	na

Section B.3: Notes, Comments, and Explanations

Division for Air Quality

300 Sower Boulevard
Frankfort, KY 40601
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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: 12/13/2022

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)
COMB19, 58	Unit 12 Gas Turbine with HRSG															
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	NOX	85.406	LKE Requirement; See Section 5.3 in Appendix B	na	90%	337.1	33.7	1,476.7	147.7
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	CO	51.963	LKE Requirement; See Section 5.3 in Appendix B	na	90%	205.1	20.5	898.4	89.8
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	VOC	3.628	LKE Requirement; See Section 5.3 in Appendix B	na	50%	14.32	7.16	62.7	31.4
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	PT	5.684	Vendor Estimate; See Section 5.3 in Appendix B	na	na	22.4	22.4	98.3	98.3

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	PM10	5.684	Vendor Estimate; See Section 5.3 in Appendix B	na	na	22.4	22.4	98.3	98.3
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	PM2.5	5.684	Vendor Estimate; See Section 5.3 in Appendix B	na	na	22.4	22.4	98.3	98.3
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	SO2	1.427	Pipeline spec conversion; See Section 5.3 in Appendix B	na	na	5.63	5.63	24.7	24.7
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	H2SO4	0.503	Pipeline spec conversion; See Section 5.3 in Appendix B	na	na	1.98	1.98	8.69	8.69
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	NH3	7.100	LKE Requirement; See Section 5.3 in Appendix B	na	na	28.0	28.0	122.8	122.8
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	CO2	123,177	40 CFR 98, Table C-1	na	na	486,246	486,246	2,129,759	2,129,759
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	CH4	8.772	AP-42, Table 3.1-2a	na	na	34.6	34.6	151.7	151.7
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	N2O	3.060	AP-42, Table 3.1-2a	na	na	12.1	12.1	52.9	52.9
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	Acetaldehyde	0.359	AP-42 Table 3.1 & 3-4 of BID	na	50%	1.417	0.709	6.21	3.10
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	Formaldehyde	0.724	LKE Requirement; See Section 5.3 in Appendix B	na	68.44%	2.859	0.902	12.52	3.95
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	Hexane	1.8	AP-42 Table 1.4-3	na	50%	7.106	3.553	31.12	15.56
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	Toluene	0.133	AP-42 Table 3.1	na	50%	0.523	0.262	2.29	1.15
COMB19, 58	Unit 12 Gas Turbine with HRSG	1	Natural Gas Firing in GT & DB	Oxidation Catalyst; SCR	C34, C35	58	3.948	Xylenes	0.065	AP-42 Table 3.1	na	50%	0.258	0.129	1.13	0.56

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
COMB19, 58	Unit 12 Gas Turbine with HRSG	2	Cold Startup Events	na	na	58	1	NOX	420	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	420	420	1.05	1.05
COMB19, 58	Unit 12 Gas Turbine with HRSG	2	Cold Startup Events	na	na	58	1	CO	758	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	758	758	1.90	1.90
COMB19, 58	Unit 12 Gas Turbine with HRSG	2	Cold Startup Events	na	na	58	1	VOC	135	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	135	135	0.34	0.34
COMB19, 58	Unit 12 Gas Turbine with HRSG	2	Cold Startup Events	na	na	58	1	PT	32	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	32	32	0.08	0.08
COMB19, 58	Unit 12 Gas Turbine with HRSG	2	Cold Startup Events	na	na	58	1	PM10	32	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	32	32	0.08	0.08
COMB19, 58	Unit 12 Gas Turbine with HRSG	2	Cold Startup Events	na	na	58	1	PM2.5	32	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	32	32	0.08	0.08
COMB19, 58	Unit 12 Gas Turbine with HRSG	3	Warm Startup Events	na	na	58	1	NOX	260	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	260	260	5.85	5.85
COMB19, 58	Unit 12 Gas Turbine with HRSG	3	Warm Startup Events	na	na	58	1	CO	476	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	476	476	10.71	10.71
COMB19, 58	Unit 12 Gas Turbine with HRSG	3	Warm Startup Events	na	na	58	1	VOC	121	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	121	121	2.72	2.72
COMB19, 58	Unit 12 Gas Turbine with HRSG	3	Warm Startup Events	na	na	58	1	PT	27	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	27	27	0.61	0.61
COMB19, 58	Unit 12 Gas Turbine with HRSG	3	Warm Startup Events	na	na	58	1	PM10	27	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	27	27	0.61	0.61
COMB19, 58	Unit 12 Gas Turbine with HRSG	3	Warm Startup Events	na	na	58	1	PM2.5	27	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	27	27	0.61	0.61
COMB19, 58	Unit 12 Gas Turbine with HRSG	4	Hot Startup Events	na	na	58	1	NOX	135	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	135	135	6.75	6.75

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
COMB19, 58	Unit 12 Gas Turbine with HRSG	4	Hot Startup Events	na	na	58	1	CO	303	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	303	303	15.15	15.15
COMB19, 58	Unit 12 Gas Turbine with HRSG	4	Hot Startup Events	na	na	58	1	VOC	91	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	91	91	4.55	4.55
COMB19, 58	Unit 12 Gas Turbine with HRSG	4	Hot Startup Events	na	na	58	1	PT	15	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	15	15	0.75	0.75
COMB19, 58	Unit 12 Gas Turbine with HRSG	4	Hot Startup Events	na	na	58	1	PM10	15	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	15	15	0.75	0.75
COMB19, 58	Unit 12 Gas Turbine with HRSG	4	Hot Startup Events	na	na	58	1	PM2.5	15	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	15	15	0.75	0.75
COMB19, 58	Unit 12 Gas Turbine with HRSG	5	Shutdown Events	na	na	58	1	NOX	78	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	78	78	5.85	5.85
COMB19, 58	Unit 12 Gas Turbine with HRSG	5	Shutdown Events	na	na	58	1	CO	244	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	244	244	18.30	18.30
COMB19, 58	Unit 12 Gas Turbine with HRSG	5	Shutdown Events	na	na	58	1	VOC	118	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	118	118	8.85	8.85
COMB19, 58	Unit 12 Gas Turbine with HRSG	5	Shutdown Events	na	na	58	1	PT	5	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	5	5	0.38	0.38
COMB19, 58	Unit 12 Gas Turbine with HRSG	5	Shutdown Events	na	na	58	1	PM10	5	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	5	5	0.38	0.38
COMB19, 58	Unit 12 Gas Turbine with HRSG	5	Shutdown Events	na	na	58	1	PM2.5	5	LKE Requirement for Prospective Vendors; See Section 5.5 in Appendix B	na	na	5	5	0.38	0.38
COMB20, 59	Auxiliary Steam Boiler															
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	NOX	38.339	LKE Requirement; See Section 6.2 in Appendix B	na	na	3.637	3.637	15.93	15.93

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	CO	38.900	LKE Requirement; See Section 6.2 in Appendix B	na	na	3.690	3.690	16.16	16.16
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	VOC	5.5	AP-42 Table 1.4-2	na	na	0.522	0.522	2.29	2.29
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	PT	1.90	AP-42 Table 1.4-2	na	na	0.180	0.180	0.79	0.79
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	PM10	3.47	AP-42 Table 1.4-2	na	na	0.329	0.329	1.44	1.44
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	PM2.5	3.47	AP-42 Table 1.4-2	na	na	0.329	0.329	1.44	1.44
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	SO2	1.43	Pipeline spec conversion; See Section 6.2 in Appendix B	na	na	0.135	0.135	0.59	0.59
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	H2SO4	0.109	Pipeline spec conversion; See Section 6.2 in Appendix B	na	na	0.010	0.010	0.05	0.05
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	Lead	0.0005	AP-42, Table 1.4-2	na	na	4.74E-05	4.74E-05	2.08E-04	2.08E-04
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	CO2	123,177	40 CFR 98, Table C-1	na	na	11,686	11,686	51,185	51,185
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	CH4	2.32	40 CFR 98, Table C-2	na	na	0.220	0.220	0.96	0.96
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	N2O	0.232	40 CFR 98, Table C-2	na	na	0.022	0.022	0.10	0.10
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	Formaldehyde	0.075	AP-42, Table 1.4-3	na	na	0.007	0.007	0.031	0.031
COMB20, 59	Auxiliary Steam Boiler	1	Natural Gas Combustion w/ LNB & FGR	na	na	59	0.0949	Hexane	1.8	AP-42, Table 1.4-3	na	na	0.171	0.171	0.75	0.75

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
COMB21, 60	2 MW Diesel Emergency Generator															
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	NOX	283.110	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B	na	na	38.789	38.789	9.70	9.70
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	CO	23.305	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B	na	na	3.193	3.193	0.80	0.80
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	VOC	6.042	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B	na	na	0.828	0.828	0.207	0.207
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	PT	1.726	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B	na	na	0.237	0.237	0.059	0.059
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	PM10	1.726	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B	na	na	0.237	0.237	0.059	0.059
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	PM2.5	1.726	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B	na	na	0.237	0.237	0.059	0.059
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	SO2	0.208	AP-42 Table 3.4-1	na	na	0.028	0.028	0.007	0.007
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	CO2	22,343	40 CFR 98, Subpart C, Table C-1	na	na	3,061	3,061	765.30	765.30
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	CH4	0.906	40 CFR 98, Subpart C, Table C-2	na	na	0.124	0.124	0.031	0.031
COMB21, 60	2 MW Diesel Emergency Generator	1	Diesel Fuel Combustion	na	na	60	0.1370	N2O	0.181	40 CFR 98, Subpart C, Table C-2	na	na	0.025	0.025	0.006	0.006
COMB22, 61	Fuel Gas (Dewpoint) Preheater															
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	NOX	38.339	LKE Requirement; See Section 7.2 in Appendix B	na	na	0.546	0.546	2.39	2.39

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	CO	38.900	LKE Requirement; See Section 7.2 in Appendix B	na	na	0.554	0.554	2.43	2.43
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	VOC	5.5	AP-42 Table 1.4-2	na	na	0.078	0.078	0.34	0.34
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	PT	1.90	AP-42 Table 1.4-2	na	na	0.027	0.027	0.12	0.12
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	PM10	3.47	AP-42 Table 1.4-2	na	na	0.049	0.049	0.22	0.22
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	PM2.5	3.47	AP-42 Table 1.4-2	na	na	0.049	0.049	0.22	0.22
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	SO2	1.43	Pipeline spec conversion; See Section 7.2 in Appendix B	na	na	0.020	0.020	0.089	0.089
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	H2SO4	0.109	Pipeline spec conversion; See Section 7.2 in Appendix B	na	na	0.002	0.002	0.0068	0.0068
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	Lead	0.0005	AP-42, Table 1.4-2	na	na	7.12E-06	7.12E-06	3.12E-05	3.12E-05
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	CO2	123,177	40 CFR 98, Table C-1	na	na	1,755	1,755	7,685	7,685
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	CH4	2.32	40 CFR 98, Table C-2	na	na	0.033	0.033	0.14	0.14
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	N2O	0.232	40 CFR 98, Table C-2	na	na	0.003	0.003	0.014	0.014
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	Formaldehyde	0.075	AP-42, Table 1.4-3	na	na	0.001	0.001	0.005	0.005
COMB22, 61	Fuel Gas (Dewpoint) Preheater	1	NG Fuel Combustion (15 MMBtu/hr)	na	na	61	0.0142	Hexane	1.8	AP-42, Table 1.4-3	na	na	0.026	0.026	0.11	0.11

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
COMB23, 63	400 HP Diesel Driven Fire Pump															
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	NOX	112.640	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B	na	na	2.302	2.302	0.58	0.58
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	CO	34.526	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B	na	na	0.705	0.705	0.18	0.18
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	VOC	4.316	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B	na	na	0.088	0.088	0.022	0.022
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	PT	4.316	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B	na	na	0.088	0.088	0.022	0.022
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	PM10	4.316	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B	na	na	0.088	0.088	0.022	0.022
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	PM2.5	4.316	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B	na	na	0.088	0.088	0.022	0.022
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	SO2	0.208	AP-42 Table 3.4-1 (S is sulfur content in %)	na	na	0.004	0.004	0.0011	0.0011
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	CO2	22,343	40 CFR 98, Subpart C, Table C-1	na	na	456.6	456.6	114.14	114.14
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	CH4	0.906	40 CFR 98, Subpart C, Table C-2	na	na	0.019	0.019	0.0046	0.0046
COMB23, 63	400 HP Diesel Driven Fire Pump	1	Diesel Fuel Combustion	na	na	63	0.0204	N2O	0.181	40 CFR 98, Subpart C, Table C-2	na	na	0.0037	0.0037	0.0009	0.0009
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)															
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)	1	Gallons of Recirculating Water	Drift Eliminators	C36	62	5.7	PT	0.0826	990 ppm TDS in recirculating water and 0.001% drift; See Section 8.2 in Appendix B	na	na	0.47	0.47	2.06	2.06

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		Imber Annual Emissions	
													Uncontrolled Potential (lb/hr)	Controlled Potential (lb/hr)	Uncontrolled Potential (tons/yr)	Controlled Potential (tons/yr)
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)	1	Gallons of Recirculating Water	Drift Eliminators	C36	62	5.7	PM10	0.0388	EPRI PM10/PM ratio; See Section 8.2 in Appendix B	na	na	0.22	0.22	0.97	0.97
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)	1	Gallons of Recirculating Water	Drift Eliminators	C36	62	5.7	PM2.5	1.67E-04	EPRI PM2.5/PM ratio; See Section 8.2 in Appendix B	na	na	9.51E-04	9.51E-04	4.16E-03	4.16E-03

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			Emission Unit #
		Equivalent Diameter *(ft)*	Height *(ft)*	Base Elevation *(ft)*	Northing *(m)*	Easting *(m)*	Flowrate *(acfm)*	Temperature *(°F)*	Exit Velocity *(ft/sec)*	
58	Unit 12 Gas Turbine with HRSG, Control Devices: Oxidation Catalyst; SCR	24	185	881	4,184,858	701,594	1,600,000	171	59	COMB19, 58
59	Auxiliary Steam Boiler, Control Devices:	3	60	881	4,184,896	701,599	30,000	295	71	COMB20, 59
60	2 MW Diesel Emergency Generator, Control Devices:	1.5	16	881	4,184,911	701,575	16,200	900	59	COMB21, 60
61	Fuel Gas (Dewpoint) Preheater, Control Devices:	2	18	881	4,184,977	701,565	1,250	750	71	COMB22, 61
63	400 HP Diesel Driven Fire Pump, Control Devices:	0.67	13	881	4,184,914	701,664	1,875	960	90	COMB23, 63
62	Mechanical Draft Cooling Tower (8 Cells), Control Device: Drift Eliminators	155.54	55	881	4,184,800	701,677	1,350,000 per fan	88	30	EQPT21, 62

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)*
Not applicable. There are no exterior fugitive sources at the E.W. Brown Station being added or modified as part of the NGCC Project.								

Section N.4: Notes, Comments, and Explanations

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: 12/13/2022

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)
COMB3, 003	Unit 3 Indirect Heat Exchanger	40 CFR 60.4333(a); 40 CFR 63.6105(c)	na	na	na	Following its construction and commissioning, upon commencement of normal operation of EU58 (Unit 12 Combustion Turbine), the permittee shall cease operation of EU03 (Unit 3 Boiler).	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 for the six month period during which EU58 commenced normal 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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB19, 58	**Unit 12 Gas Turbine with HRSG**	40 CFR 60.4333(a); 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.
COMB19, 58	Unit 12 Gas Turbine with HRSG	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	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	40 CFR 60.5520(a)	CO_2	1,000 lb/MWh of gross energy output or 1,030 lb/MWh of net energy output on a 12-month rolling average basis	na	na	Combust only pipeline natural gas as fuel. Calculate and record emissions monthly on a 12-month rolling average basis
COMB19, 58	Unit 12 Gas Turbine with HRSG	40 CFR 63.6100	Formaldehyde	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.

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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
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)	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 63.7505(a)	na	na	na	The Permittee shall be in compliance with the work practice standards in 40 CFR 63, Subpart DDDDD.	Comply with the 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.

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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
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.
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.
COMB21, 60	**2 MW Diesel Emergency Generator**	NSPS IIII: 40 CFR 60.4205(b); 60.4206	NMHC + NOx	From 60.4202 referenced in 60.4205, NMHC + NOx shall not exceed 6.4 g/kW-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)).

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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB21, 60	2 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4205(b); 60.4206	CO	From 60.4202 referenced in 60.4205, CO shall not exceed 3.5 g/kW-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)).
COMB21, 60	2 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4205(b); 60.4206	PM	From 60.4202 referenced in 60.4205, PM shall not exceed 0.20 g/kW-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)).
COMB21, 60	2 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4205(b); 60.4206	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)).
COMB21, 60	2 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.	Use only nonroad diesel fuel via 40 CFR 1039.305
COMB21, 60	2 MW Diesel Emergency Generator	NSPS IIII: 40 CFR 60.4211(a)	na	na	na	Operate and maintain stationary CI internal combustion engine and control device according to manufacturer's instructions.	Only operate following manufacturer's instructions.
COMB21, 60	2 MW Diesel Emergency Generator	RICE MACT: 40 CFR 63.6605	na	na	na	Good air pollution control practices for minimizing emissions.	Good air pollution control practices for minimizing emissions.

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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB21, 60	2 MW Diesel Emergency Generator	RICE MACT: 40 CFR 63.6640(f); 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 any combination of the following purposes for a maximum of 100 hours per calendar year: maintenance checks and readiness testing, emergency demand response for periods authorized by NERC as Energy Emergency Alert Level 2, deviation of voltage/frequency of 5 percenter of greater below standard, up to 50 hours per calendar year in non-emergency situations (not for peak shaving or non-emergency demand response or generating income) as part of the 100 hours.	Operate generators according to hour limitations for maintenance, non-emergency, demand response, etc.
COMB21, 60	2 MW Diesel Emergency Generator	RICE MACT: 40 CFR 63.6590(c)	na	na	na	Meet the requirements of 40 CFR 63 Subpart ZZZZ by complying with 40 CFR 60 Subpart IIII.	Comply with NSPS IIII
COMB22, 61	**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.
COMB22, 61	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7500(a)(1)	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.
COMB22, 61	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.
COMB22, 61	Fuel Gas (Dewpoint) Preheater	Boiler MACT: 40 CFR 63.7505(a)	na	na	na	The Permittee shall be in compliance with the work practice standards in 40 CFR 63, Subpart DDDDD.	Comply with the 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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB22, 61	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.
COMB22, 61	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.
COMB22, 61	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.
COMB22, 61	Fuel Gas (Dewpoint) Preheater	401 KAR 59:015, Section 4(2)	Opacity	20%	na	na	Equipment design and use of natural gas as fuel.
COMB22, 61	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.

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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB22, 61	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.
COMB23, 63	**400 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, 63	400 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, 63	400 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, 63	400 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)).
COMB23, 63	400 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4207(b)	na	na	na	Use diesel fuel that meets requirements of 40 CFR 1090.305 for nonroad diesel fuel.	Purchase only compliant diesel fuel.

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)	Imber Method of Determining Compliance with the Emission and Operating Requirement(s)
COMB23, 63	400 HP Diesel Driven Fire Pump	NSPS IIII: 40 CFR 60.4211(a)	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, 63	400 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.
EQPT21, 62	**Mechanical Draft Cooling Tower (8 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.
EQPT21, 62	Mechanical Draft Cooling Tower (8 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.

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**	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	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	SO_2	40 CFR 60.4365(a)	Fuel sulfur content	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	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	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	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.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Monitored	Description of Monitoring
COMB20, 59	Auxiliary Steam Boiler	na	40 CFR 60.48c(g)(2)	NG Usage	The permittee shall monitor natural gas (MMscf) on a monthly basis.
COMB21, 60	2 MW Diesel Emergency Generator	na	NSPS IIII: 40 CFR 60.4209(a)	Operating Hours	Install a non-resettable hour meter prior to startup of the engine and monitor hours of operation.
COMB22, 61	Fuel Gas (Dewpoint) Preheater	na	40 CFR 60.48c(g)(2)	NG Usage	The permittee shall monitor natural gas (MMscf) on a monthly basis.
COMB23, 63	400 HP Diesel Driven Fire Pump	na	NSPS IIII: 40 CFR 60.4209(a)	Operating Hours	Install a non-resettable hour meter prior to startup of the engine and monitor hours of operation.
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)	VE	401 KAR 59:010	Processing Rate	The permittee shall monitor the processing rate (gallons/hr) on a monthly basis.
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)	PM	401 KAR 59:010	Processing Rate	The permittee shall monitor the processing rate (gallons/hr) 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	na	40 CFR 60.5525	Fuel Purchased	Maintain fuel purchase records for the permitted fuel(s).
COMB19, 58	Unit 12 Gas Turbine with HRSG	NOX	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	CO_2	40 CFR 60.5520(d)(1)	CO_2 Emission Rate	Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 160 lb CO2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.
COMB19, 58	Unit 12 Gas Turbine with HRSG	Formaldehyde	40 CFR 63.6155(a)	Notifications and Reports	Keep the records as described in 40 CFR 63.6155(a)(1) through (7).
COMB19, 58	Unit 12 Gas Turbine with HRSG	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.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
COMB19, 58	Unit 12 Gas Turbine with HRSG	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.
COMB19, 58	Unit 12 Gas Turbine with HRSG	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).
COMB20, 59	**Auxiliary Steam Boiler**	na	NSPS Dc: 40 CFR 60.48c(g)	Fuel Combusted	Maintain records of 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	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.

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 63.7560(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.
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.
COMB21, 60	**2 MW Diesel Emergency Generator**	na	NSPS IIII: 40 CFR 60.4214(b)	Operating Hours	Maintain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.
COMB22, 61	**Fuel Gas (Dewpoint) Preheater**	na	NSPS Dc: 40 CFR 60.48c(g)	Fuel Combusted	Maintain records of 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).
COMB22, 61	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).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
COMB22, 61	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.
COMB22, 61	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).
COMB22, 61	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.
COMB22, 61	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	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.
COMB23, 63	**400 HP Diesel Driven Fire Pump**	na	NSPS IIII: 40 CFR 60.4214(b)	Operating Hours	Maintain records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Recorded	Description of Recordkeeping
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)	VE	401 KAR 59:010	Processing Rate	Retain records of the processing rate (gallons/hr) on a monthly basis.
EQPT21, 62	Mechanical Draft Cooling Tower (8 Cells)	PM	401 KAR 59:010	Processing Rate	Retain records of the processing rate (gallons/hr) on a monthly basis.

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	NO_X	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	NO_X	40 CFR 60.4395	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	na	40 CFR 60.5550	Initial Notifications	Prepare and submit the notifications specified in 40 CFR 60.7(a)(1) and (3) and 60.19, as applicable.
COMB19, 58	Unit 12 Gas Turbine with HRSG	Formaldehyde	40 CFR 63.6140(b)	Emission/Operating Limits	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	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	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).
COMB19, 58	Unit 12 Gas Turbine with HRSG	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.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB19, 58	Unit 12 Gas Turbine with HRSG	Formaldehyde	40 CFR 63.6150(a)	Semiannual Compliance Report	Anyone who owns or operates a stationary combustion turbine which must meet the emission limitation for formaldehyde must 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	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	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	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).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB20, 59	**Auxiliary Steam Boiler**	na	NSPS Dc: 40 CFR 60.48c(a)	Initial Notifications	Submit notification of date of construction or reconstruction and actual startup as provided by 60.7. Notification shall include design heat input capacity and identification of fuels to be combusted, annual capacity factor anticipates operating based on each fuel fired and all fuels fired.
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).

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 63.7550(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	2 MW Diesel Emergency Generator	na	RICE MACT: 40 CFR 63.6645(f)	Initial Notifications	Submit initial notification in accordance with 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 63.6645(c), the initial notification should be submitted no later than 120 days after startup(since 63.6595(a)(3) states startup is when compliance begins).
COMB22, 61	Fuel Gas (Dewpoint) Preheater	na	NSPS Dc: 40 CFR 60.48c(a)	Initial Notifications	Submit notification of date of construction or reconstruction and actual startup as provided by 60.7. Notification shall include design heat input capacity and identification of fuels to be combusted, annual capacity factor anticipates operating based on each fuel fired and all fuels fired.
COMB22, 61	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.
COMB22, 61	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).
COMB22, 61	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.
COMB22, 61	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.
COMB22, 61	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.
COMB22, 61	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).

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Reported	Description of Reporting
COMB22, 61	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).
COMB22, 61	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.
COMB22, 61	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.
COMB22, 61	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).
COMB22, 61	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).
COMB22, 61	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).

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**	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	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	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	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	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	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	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	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.
COMB20, 59	**Auxiliary Steam Boiler**	na	Boiler MACT: 40 CFR 63.7510(g)	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7540(a)	na	The Permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	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.
COMB20, 59	Auxiliary Steam Boiler	na	Boiler MACT: 40 CFR 63.7540(a)(13)	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.
COMB22, 61	**Fuel Gas (Dewpoint) Preheater**	na	Boiler MACT: 40 CFR 63.7510(g)	na	Demonstrate initial compliance with applicable work practice standards in Table 3 annually as specified in 63.7515(d).
COMB22, 61	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7540(a)	na	The Permittee shall demonstrate continuous compliance with the work practice standards in Table 3 to 40 CFR 63, Subpart DDDDD that apply.

Emission Unit #	Emission Unit Description	Pollutant	Applicable Regulation or Requirement	Parameter Tested	Description of Testing
COMB22, 61	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7540(a)(10) or (12)	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.
COMB22, 61	Fuel Gas (Dewpoint) Preheater	na	Boiler MACT: 40 CFR 63.7540(a)(13)	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.

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.

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: 12/13/2022

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	
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	
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	
4	Unleaded gasoline storage tanks	T-25 (Coal Yard/Tractor Garage Area)	NA	

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	
6	Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons)	R8, R9, R10, R11	NA	
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	
9	Distillate Oil and/or Propane Coal Belt Heaters		NA	
10	Limestone Storage Pile		401 KAR 63.010	
11	Limestone Reclaim Maintenance Tunnel Exhaust Vent		401 KAR 59:010	
12	Sorbent Storage Silos (for SO3 mitigation)		401 KAR 59:010	
13	Natural Gas Distillate tank (2,000 gallons)	T-9 (CT area)	NA	
14	Diesel Fuel tanks for emergency generators (3 @ 391 gallons)	T3, T4, T5 (CT area/Emergency Generators)	NA	
15	Diesel Fuel tank for emergency fire pump (300 gallons)	T-8 (CT area/emergency fire pump AST)	NA	

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
16	Liquid Hg Control Additives		NA	
17	Diesel Fuel tank for emergency generator (837 gallons)	T-14 (Steam Plant/Unit 3 Emergency Generator)	NA	
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	
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	
20	Turbine oil reservoirs for Unit 3 feed pump (2 each @ 1,000 gallons)	R4, R44	NA	
21	Turbine oil reservoir for Unit 3 seal oil (150 gallons)	R14	NA	
22	Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons)	R18, R19 (Unit 3, outside out of service ESP)	NA	
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	
25	PAC Storage Silos		401 KAR 59:010	
26	Bottom Ash Transport		401 KAR 63.010	
27	Fly Ash Transport		401 KAR 63.010	

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
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 & Process Water System Solids (Wind Erosion)		401 KAR 63.010	
31	Slipstream Carbon Dioxide (CO2) 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 59.010	

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
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)		NA	
38	Diesel Fuel tanks for emergency generators (2 @ 900 gallons)	T-6, T-7 CT area/between CT7 & CT8(EU28 & EU25)	NA	
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	
40	Mobile Diesel Fuel Tank (251 gallons/square tank)	T-39 (Stored in CT Warehouse when not in use)	NA	
41	Lube Oil System with Demister Vents	TBD	NA	0.66 tpy (Refer to Section 12 in Appendix B of the application package.
42	Diesel Storage Tanks for NGCC Units (1@ 4,000 gal 1@ 440 gal)	TBD	401 KAR 59:050 (only for 4,000 gal tank)	0.6 tpy (Refer to Section 13 in Appendix B of the application package.

Insignificant Activity #	Description of Activity including Rated Capacity	Serial Number or Other Unique Identifier	Applicable Regulation(s)	Calculated Emissions
43	HVAC Heaters (Total <10 MMBtu/hr)	TBD	NA	4.2 tpy of NOX and 3.5 tpy of CO (Refer to Section 11 in Appendix B of the application package.
	NOTE: Blue font are existing IAs. New Insignificant Activities being added to Section C of the Title V permit via the NGCC Project permit action are shown in green font. Those IAs being shut down in conjunction with the commissioning of the NGCC project are shown above in an orange font. Storage vessels impacted by the Unit 3 closure will be removed after the IA's are physically removed or disconnected and empty. A future revised 7007DD form will be provided to KDAQ after the IA's are formally closed, signaling their removal from Section C of the Title V permit.			

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...	12/15/2022 | 8:18 AM EST
	Authorized Signature	**Date**
	Steven Turner	Vice President, Power Production
	Type/Print Name of Signatory	**Title of Signatory**

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 NGCC Project permit action are shown in green font. Those IAs being shut down in conjunction with the commissioning of the NGCC project are shown in orange font. Storage vessels impacted by the Unit 3 closure will be removed after the IA's are physically removed or disconnected and empty. A future revised 7007DD form will be provided to KDAQ after the IA's are formally closed, signaling their removal from Section C of the Title V permit.
Refer to prior applications for emission calculations for existing insignificant activities not affected by the NGCC Project.

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: 12/13/2022

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
COMB21, 60	2 MW Diesel Emergency	na	60	Caterpillar 3516C or Similar		Estimated 2024	Estimated 2024	03/2025		na	NSPS IIII; NESHAP ZZZZ
COMB23, 63	400 HP Diesel Driven Fire Pump	na	63	Clarke JW6H-UFAD80 or Similar		Estimated 2024	Estimated 2024	03/2025		na	NSPS IIII; NESHAP ZZZZ

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)
COMB21, 60	Emergency Electrical Generator Power	Estimated maximum of 500 hr/yr	No	na	na
COMB23, 63	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
COMB21, 60	Stationary	Compression	4-stroke	2,682	1,800	78.1	16
COMB23, 63	Stationary	Compression	4-stroke	400	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
COMB21, 60	Primary	Diesel	ULSD	100	0.137 Mgal/hr	137.03 MMBtu/Mgal	0.0015%	20100102	Mgal
COMB23, 63	Primary	Diesel	ULSD	100	0.020 Mgal/hr	137.03 MMBtu/Mgal	0.0015%	20200102	Mgal

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
COMB21, 60	Diesel	NOX	283.110	lb/Mgal	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B
COMB21, 60	Diesel	CO	23.305	lb/Mgal	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B
COMB21, 60	Diesel	VOC	6.042	lb/Mgal	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B
COMB21, 60	Diesel	PT	1.726	lb/Mgal	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B
COMB21, 60	Diesel	PM10	1.726	lb/Mgal	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B
COMB21, 60	Diesel	PM2.5	1.726	lb/Mgal	Manufacturer Emissions Datasheet; See Section 9.2 in Appendix B
COMB21, 60	Diesel	SO2	0.208	lb/Mgal	AP-42 Table 3.4-1
COMB21, 60	Diesel	CO	22,343	lb/Mgal	40 CFR 98, Subpart C, Table C-1
COMB21, 60	Diesel	CH4	0.906	lb/Mgal	40 CFR 98, Subpart C, Table C-2
COMB21, 60	Diesel	N2O	0.181	lb/Mgal	40 CFR 98, Subpart C, Table C-2

Imber

Emission Unit #	Fuel	Pollutant	Emission Factor	Emission Factor Units	Source of Emission Factor
COMB23, 63	Diesel	NOX	112.640	lb/Mgal	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B
COMB23, 63	Diesel	CO	34.526	lb/Mgal	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B
COMB23, 63	Diesel	VOC	4.316	lb/Mgal	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B
COMB23, 63	Diesel	PT	4.316	lb/Mgal	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B
COMB23, 63	Diesel	PM10	4.316	lb/Mgal	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B
COMB23, 63	Diesel	PM2.5	4.316	lb/Mgal	Manufacturer Emissions Datasheet; See Section 10.2 in Appendix B
COMB23, 63	Diesel	SO2	0.208	lb/Mgal	40 CFR 98, Subpart C, Table C-1
COMB23, 63	Diesel	CO	22,343	lb/Mgal	40 CFR 98, Subpart C, Table C-2
COMB23, 63	Diesel	CH4	0.906	lb/Mgal	40 CFR 98, Subpart C, Table C-2
COMB23, 63	Diesel	N2O	0.181	lb/Mgal	40 CFR 98, Subpart A

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.

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)

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

Permit #: V-17-030 R1

Agency Interest (AI) ID: 3148

Date: 12/13/2022

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: Temperature (°F)	Flowrate (scfm @ 68°F)	Average Particle Diameter (μm)	Particle Density (lb/ft^3) or Specific	Gas Density (lb/ft^3)	Inlet Gas Stream Data For Condensers, Adsorbers, Afterburners, Incinerators, Oxidizers Only: Gas Moisture Content (%)	Gas Composition	Fan Type	Equipment Operational Data For All Control Devices: Pressure Drop Range (in. H_2O)	Pollutants Collected/ Controlled	Pollutant Removal (%)
C34	Oxidation Catalyst	na	See GG.12		03/2025	600-1,200	na	na	na	na	na	na	na	0.5-1.0	CO VOC	90% 50%
C35	SCR	na	See GG.12		03/2025	575-625	na	na	na	na	na	na	na	0.6-1.0	NOX	90%
C36	Drift Eliminators	na	See GG.12		03/2025	na	na	na	na	na	na	na	na	na	PM	Drift Loss = 0.0010%

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			
							Type	Injection Rate			Catalyst			
					Min (°F)	Max (°F)		Min (lb/hr)	Max (lb/hr)		Composition	Volume (ft^3)	Weight (lb)	Replacement Schedule
C35	COMB19, 58 - Unit 12 Gas Turbine with HRSG; Refer to Process Flow Diagram in Appendix B	SCR	Refer to Section 5 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; Refer to Process Flow Diagram in Appendix B	Oxidation Catalyst - Refer to Process Flow Diagram in Appendix A
C36	EQPT21, 62 - Mechanical Draft Cooling Tower (8 Cells); Refer to Process Flow Diagram in Appendix B	Integrated Mist Eliminator with Drift Loss Specification of no greater than 0.0010%

Section GG.12: Notes, Comments, and Explanations
Construction of equipment associated with the NGCC Project is not targeted to commence until March 2025. The specific vendors and model numbers of air pollution control equipment planned will not be known until farther in the project schedule.

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
Unit 12 (Emissions Unit 58)	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

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).

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

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

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	Steve Turner		
Signature	DocuSigned by: Steven B. Turner 8AD647306F3F4A0...	Date	12/15/2022 | 8:18 AM EST

Instructions for the Acid Rain Program Permit Application

Imber

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy=s (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Acid Rain Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

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 operating permit, sample suggested edits to Brown Generating Station's existing Title V permit (V-17-030 R1) (shown in blue font) that reflect the new and modified regulatory and permitting requirements impacted by the NGCC Project are provided in this appendix.

The suggested provisions for new emission units encompass the operating limits, emission standards, and associated compliance assurance monitoring provisions that are derived from applicable regulations and/or are believed to be appropriate to address the permitting requirements triggered by the NGCC Project. KU understands that the Division retains the authority and responsibility for developing an amended Title V permit that the agency believes is appropriate for the project. These suggested provisions are only being provided to promote efficiency and timeliness in the agency's review.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality
300 Sower Boulevard, 2nd Floor
Frankfort, Kentucky 40601
(502) 564-3999

Final

AIR QUALITY PERMIT
Issued under 401 KAR 52:020

Permittee Name:	**Kentucky Utilities Company**
Mailing Address:	**P.O. Box 32010, Louisville, KY 40232**
Source Name:	**Kentucky Utilities Company - E.W. Brown Generating Station**
Mailing Address:	**815 Dix Dam Road, Harrodsburg, KY 40330**
Source Location:	**815 Dix Dam Road**
Permit:	**V-17-030 R1**
Agency Interest:	**3148**
Activity:	**APE20200004**
Review Type:	**Title V, Operating**
Source ID:	**21-167-00001**
Regional Office:	**Frankfort Regional Office 300 Sower Boulevard, 1st Floor Frankfort, KY 40601 (502) 564-3358**
County:	**Mercer**
Application Complete Date:	**December 10, 2015**
Issuance Date:	**June 8, 2019**
Revision Date:	**July 16, 2021**
Expiration Date:	**June 8, 2024**

X Rick Shewekah

For Melissa Duff, Director
Division for Air Quality

Version 10/16/13

TABLE OF CONTENTS

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

Version 1/26/2021

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.

SECTION B - EMISSION UNITS, EMISSION POINTS, 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)(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, *CSAPR NO_x Ozone Season Group 3 Trading Program*

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").

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

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.

   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)].

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

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)].

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)].

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

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. [40 CFR 63.10021(e)(9)]

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).

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (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). The permittee shall provide reports concerning activities and startup periods, as specified in 40 CFR 63.10011(g), 63.10021(i), and 63.10031.
[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.

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (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). [Preclude 401 KAR 51:017]

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:

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

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.

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

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

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**. If the dispatch 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 permittee shall use SCR operational data, as required by **5. <u>Specific Recordkeeping Requirements</u>(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:

$$SAM_{\text{Fuel Oil}}\left(\frac{\text{tons}}{\text{month}}\right) = \frac{\mathit{Fuel\ Oil\ Usage}\left(\frac{10^3\ \text{gal}}{\text{month}}\right) \times EF\left(\frac{\text{lb SO}_3}{10^3\ \text{gal}}\right)}{2000\left(\frac{\text{lb}}{\text{ton}}\right)} \times 1.225\left(\frac{\text{lb H}_2\text{SO}_4}{\text{lb SO}_3}\right)$$

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:

$$SAM_{FGD} = \frac{\mathit{Heat\ Input}_{FGD}\left(\frac{\text{MMBtu}}{\text{month}}\right) \times EF_{FGD}\left(\frac{\text{lb SO}_3}{\text{MMBtu}}\right)}{2000\left(\frac{\text{lb}}{\text{ton}}\right)} \times 1.225\left(\frac{\text{lb H}_2\text{SO}_4}{\text{lb SO}_3}\right)$$

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (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. <u>Testing Requirements</u>(c)**.

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

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 **OR** 0.040 lb/GWh	
Selenium	5.0 lb/TBtu	

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

Pollutant	Emission Limit	Compliance Demonstration
	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]

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

SECTION B - EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (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 4^{th} 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)].

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

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 [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)].

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

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, 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. <u>Testing Requirements</u> (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. <u>Testing Requirements</u>(d)**. An excursion shall be any hourly average that is outside the indicator range established during the performance test.

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

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. <u>Testing Requirements</u>** (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. 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)]

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 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 zero and span adjustments, failure to collect required data is a deviation from the monitoring system requirements [40 CFR 63.10020(d)].

5. <u>Specific Recordkeeping Requirements:</u>

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].

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

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].

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. [40 CFR 63.10032(a)]

   i. A copy of each notification and report submitted to comply with 40 CFR 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report 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)].

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

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)].

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)]

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

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)];

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)].

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

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;

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;

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

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. <u>Specific Monitoring Requirements</u>(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)]

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].

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

e. The permittee shall submit a compliance report which shall contain: [40 CFR 63.10031(a) referencing Item 1. 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).

      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)]

         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)].

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

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)].

ii. 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) referencing Item 1.b. of Table 8 to Subpart UUUUU of Part 63]

iii. 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) 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 [40 CFR 63.10031(g)].

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

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

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.

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(g)]

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

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

Emission Units 45-46 & 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)	April 2007	375	Diesel	None
63	NGCC Emergency Fire Pump Engine	Planned 2025	400	Diesel	None

<u>APPLICABLE REGULATIONS</u>:

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

<u>Note</u>: D.C. Circuit Court [*Delaware v. EPA*, 785 F. 3d 1 (D.C. Cir. 2015)] has vacated the provisions in 40 CFR 60, Subpart IIII that contain the 100-hour exemption for operation of emergency engines for purposes of emergency demand response under 40 CFR 60.4211(f)(2)(ii)-(iii). The D.C. Circuit Court issued the mandate for the vacatur on May 4, 2016.

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. **<u>Operating Limitations</u>:**
   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 ~~80.510(b)~~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.

   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)

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

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)].

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

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

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)]

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

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 EU63:

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 Parts 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)].

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

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.

SECTION B - EMISSION UNITS, EMISSION POINTS, 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)	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)	Diesel	None
49	Generac Make: Doosan; Model: 390; 10 cylinder, 18.3 L total displacement –Tier 2, emergency engine	2010	752 HP (561 kW)	Diesel	None
51 & 52	2 Cummins QSK23-G7 NR2, Tier 2 certified emergency engines	2014	1220 HP each	Diesel	None
60	NGCC Plant Tier 2 certified emergency engine	Planned 2025	2,682 HP (2 MW)	Diesel	None

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*

Note: D.C. Circuit Court [*Delaware v. EPA*, 785 F. 3d 1 (D.C. Cir. 2015)] has vacated the provisions in 40 CFR 60, Subpart IIII that contain the 100-hour exemption for operation of emergency engines for purposes of emergency demand response under 40 CFR 60.4211(f)(2)(ii)-(iii). The D.C. Circuit Court issued the mandate for the vacatur on May 4, 2016.

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)].

   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)].

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

c. The permittee shall use diesel fuel certified to the standards in 40 CFR ~~80.510(b)~~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.

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

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

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)].

SECTION B - EMISSION UNITS, EMISSION POINTS, 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. <u>Emission Limitations</u>:

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 ~~89.112~~1039, Appendix I~~ and 40 CFR 89.113~~, for all pollutants, and the smoke standards as specified in 40 CFR 1039.105 beginning in model year 2007~~for the appropriate Tier~~ [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. <u>Testing Requirements</u>**. [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 Parts 89, 94, and/or 1068, as they apply. [40 CFR 60.4211(a) and 40 CFR 60.4206]

3. <u>Testing Requirements</u>:

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. <u>Specific Monitoring Requirements</u>:

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

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

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

Emission Unit 58 Gas Turbine with HRSG (664 MW Net)

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel	Control Equipment
58	Combustion Turbine Combined Cycle (KU Unit 12)	Proposed 2025	4,157 MMBtu/hr	Natural Gas	Ammonia injection, SCR catalyst, CO oxidation catalyst

Applicable Regulations:
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), implementing **40 CFR 60, Subpart KKKK**, *Standards of Performance for Stationary Combustion Turbines*;
401 KAR 60:005, Section 2(2)(jjjj), implementing **40 CFR 60, Subpart TTTT,** *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units;*
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*.
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, *CSAPR NO_x Ozone Season Group 3 Trading Program*
40 CFR 75, Appendix E, *Optional NO_x Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units*

Precluded Regulations:
401 KAR 51:017, *Prevention of significant deterioration of air quality*

1. Operating Limitations:

a. At all times, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether 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); 40 CFR 60.4333(a)]

b. Stationary combustion turbines subject to a heat input-based standard in Table 2 of NSPS TTTT that are only permitted to burn one or more uniform fuels, as described in 40 CFR 60.5520(d)(1), are only subject to the monitoring requirements in 40 CFR 60.5520(d)(1).

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

All other stationary combustion turbines subject to a heat input based standard in Table 2 are subject to the requirements in 40 CFR 60.5520(d)(2). [40 CFR 60.5520(d)]

i. Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (i.e., uniform fuels) that result in a consistent emission rate of 160 lb CO_2/MMBtu or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

c. Combustion turbines qualifying under 40 CFR 60.5520(d)(1) are not subject to any requirements in 40 CFR 60.5525(a) through (c) other than the requirement to maintain fuel purchase records for permitted fuel(s). [40 CFR 60.5525]

d. 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 simple cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less. 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]

e. The permittee must 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 NESHAP YYYY]

f. Duct burners and waste heat recovery units are considered steam generating units and are not covered under NESHAP 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]

g. The permittee must comply with the emissions limitations and operating limitations of NESHAP YYYY upon startup of the affected source. [40 CFR 63.6095(a)(4)]

2. **Emission Limitations:**

a. EU58 (Combustion Turbine), which fires natural gas and has a combustion turbine heat input at peak load (HHV) greater than 850 MMBtu/hr, shall meet an emission limit of 15 parts per million (ppm) at 15% oxygen (O_2); or 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour (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,

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

Table 1]

b. Turbines operating at less than 75 percent peak load that have a combustion turbine heat input at peak load (HHV) greater than 30 MW output 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]

c. The owner or operator shall not burn in the subject stationary combustion turbine (EU58) 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)]

d. The CO_2 emissions of each affected turbine (EU58) on a 12-month rolling average basis shall not exceed one of the following limits, consistent with 40 CFR 60.5520(b), (c), and (d), as applicable: [40 CFR 60.5520(a) and 60.5525(a) and Table 2 of NSPS TTTT]

   i. 1,000 lb/MWh of gross energy output; or
   ii. 1,030 lb/MWh of net energy output.

e. EU58, which is a lean premix gas-fired stationary combustion turbine 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 NESHAP YYYY]

Compliance Demonstration:
Compliance shall be demonstrated according to **3. Testing Requirements(a-f), 4. Specific Monitoring Requirements(a-h), 5. Specific Recordkeeping Requirements(a-d)** and **6. Specific Reporting Requirements(a-o)**.

3. Testing Requirements:

a. If the owner or operator elects to install and certify a NO_X-diluent CEMS under 40 CFR 60.4345, then 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

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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 owner or operator may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The owner or operator must 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 must 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 must be demonstrated at each tested load level. Compliance is achieved if the three-run 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 owner or operator 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 must 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)]

d. The permittee 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). [40 CFR 63.6110(b)]

i. The test must have been conducted using the same methods specified in NESHAP YYYY, and these methods must have been followed correctly. [40 CFR 63.6110(b)(1)]

ii. The test must not be older than 2 years. [40 CFR 63.6110(b)(2)]

iii. The test must be reviewed and accepted by the Division. [40 CFR 63.6110(b)(3)]

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iv. Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes. [40 CFR 63.6110(b)(4)]

v. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load. [40 CFR 63.6110(b)(5)]

e. Subsequent performance tests for formaldehyde must be performed on an annual basis as specified in Table 3 of NESHAP YYYY. [40 CFR 63.6115]

f. The permittee must conduct each performance test in Table 3 of 40 CFR 63 Subpart YYYY that applies. [40 CFR 63.6120(a)]

i. Each performance test must be conducted according to the requirements in Table 3 of 40 CFR 63 Subpart YYYY. Before September 8, 2020, each performance test must be conducted according to the requirements of the General Provisions at 40 CFR 63.7(e)(1). [40 CFR 63.6120(b)]

ii. 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. [40 CFR 63.6120(c)]

iii. You must conduct three separate test runs for each formaldehyde performance test, and each test run must last at least 1 hour. [40 CFR 63.6120(d)]

4. Specific Monitoring Requirements:

a. As an alternative to performing annual performance tests, the owner or operator 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 owner or operator may install, certify, maintain, and operate a CEMS

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consisting of a NO_X monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_X emission rate in ppm or lb/MMBtu; and [40 CFR 60.4335(b)(1)]

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

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

manufacturer's instructions. [40 CFR 60.4345(d)]

v. The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs 40 CFR 60.4345(a), (c), and (d). For the CEMS and fuel flow meters, the owner or operator may, with Division approval, satisfy the 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 owner or operator shall identify excess emissions using the following guidelines: [40 CFR 60.4350]

i. All CEMS data must 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 must 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 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 owner or operator has installed and certified a NO_X diluent CEMS to meet the requirements of 40 CFR 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 must 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

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

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)]

$$E = \frac{(NO_X)_h * (HI)_h}{P} \qquad \text{(Eq. 1)}$$

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

$$P = (PE)_t + (PE)_c + Ps + Po \qquad \text{(Eq. 2)}$$

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)

$$Ps = \frac{Q * H}{3.413 \text{ x } 10^6 \text{ Btu/MWh}} \qquad \text{(Eq. 3)}$$

Where:
Ps = 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,
H = enthalpy of steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and
3.413 x 10^6 = conversion from Btu/hr to MW.
Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

d. The owner or operator 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 owner or operator must use one of the following sources of information to make the required demonstration: [40 CFR 60.4365]

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

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 SO2/MMBtu) heat input for continental areas. [40 CFR 60.4365(a)]

e. Pursuant to 40 CFR §60.5535, combustion turbines qualifying under 40 CFR 60.5520(d)(1) are not subject to any requirements for monitoring and recordkeeping other than the requirement to maintain fuel purchase records for permitted fuel(s). [40 CFR 60.5535]

f. The permittee must 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 must 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 NESHAP YYYY]

ii. Initial compliance is demonstrated if the average formaldehyde concentration meets the emission limitations specified in Table 1 of NESHAP YYYY. [40 CFR 63.6110, 63.6125, 63.6130, and Table 4 NESHAP 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 of NESHAP YYYY]

iv. The permittee must report each instance in which they did not meet each emission imitation or operating limitation. The permittee must also report each instance in which they did not meet the requirements in Table 7 of NESHAP YYYY that apply to U23/49a. 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)]

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 must conduct all parametric monitoring at all times the stationary combustion turbine is operating. [40 CFR 63.6135(a)]

h. 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,

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

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. [40 CFR 63.6135(b)]

5. Specific Recordkeeping Requirements:

a. Since the temperature monitoring system is a continuous monitoring system (CMS), the permittee must develop and implement a CMS quality control program that includes written procedures for CMS according to §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 §63.8(d)(2). [40 CFR 63.6125(e)]

b. The owner or operator must keep the records as described in 40 CFR 63.6155(a)(1) through (7). [40 CFR 63.6155(a)]

c. The owner or operator must 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)]

6. Specific Reporting Requirements:

a. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, the permittee must submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction. [40 CFR 60.4375(a)]

b. Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form 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)]

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

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 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.

c. All reports required under 40 CFR 60.7(c) shall be postmarked by the 30^{th} 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 this subpart, 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 this subpart, 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 owner or operator will use this information for compliance purposes. [40 CFR 60.4380(b)(2)]

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

e. For the affected turbines, the permittee shall comply with the notification notifications in 40 CFR 60.7(a)(1) and (3) and the reporting requirements of 40 CFR 60.19, as applicable. [40 CFR 60, Subpart A, 40 CFR 60.5550(a) and Table 3 of 40 CFR 60 Subpart TTTT]

f. The permittee must submit all of the notifications in §§ 63.7(b) Notification of Performance Testing and (c) Quality Assurance/Test Plan, 63.8(e) CMS Performance Evaluation (Except for §63.8(e)(5)(ii), which applies to COMS), 63.8(f)(4) Alternative Monitoring, and 63.9(b) Initial Notifications and (h) Notice of Compliance Status that apply to the GT by the dates specified. [40 CFR 60, Subpart A, 40 CFR 63.6145(a) and Table 7 of NESHAP YYYY]

g. If the permittee is required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with §63.6090(b), the notification must include the information in §63.9(b)(2)(i) through (v) and a statement that the new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine). [40 CFR 63.6145(d)]

h. If the permittee is required to comply with the emission limitation for formaldehyde, the permittee must submit a Notification of Compliance Status according to §63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, the permittee must 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)]

i. **Compliance report.** The owner or operator of a stationary combustion turbine which must meet the emission limitation for formaldehyde must submit a semiannual compliance report according to Table 6 of NESHAP YYYY. The semiannual compliance report must contain the information described in §63.6150(a)(1) through (5). The semiannual compliance report, including the excess emissions and monitoring system performance reports of §63.10(e)(3), must be submitted by the dates specified in §63.6150(b)(1) through (5), 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, the permittee must 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.

   ii. Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

   iii. Date of report and beginning and ending dates of the reporting period.

   iv. After September 8, 2020, report each deviation in the semiannual compliance report.

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

Report the information specified in 40 CFR 63.6150(a)(5)(i) through (iv). [40 CFR 60.4380(b)(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.

2. For each deviation, the report must 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.

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.

4. Report the total operating time of the affected source during the reporting period.

j. The first semiannual compliance report must cover the period beginning on the compliance date specified in §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 §63.6095. [40 CFR 63.6150(b)(1)]

k. The first semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified in § 63.6095 [40 CFR 63.6150(b)(2)]

l. Each subsequent semiannual 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 63.6150(b)(3)]

m. Each subsequent semiannual compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. [40 CFR 63.6150(b)(4)]

n. 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 paragraphs (b)(1) through (4) of this section. [40 CFR 63.6150(b)(5)]

o. ***Performance test report.*** After September 8, 2020, within 60 days after the date of completing each performance test required by this subpart, the owner or operator must 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)]

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

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-reporting-air-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, you 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 you claim some of the information submitted under 40 CFR 63.6150(f)(1) is CBI, you 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)]

7. Specific Control Equipment Operating Conditions:

a. The ammonia 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.

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

Emission Unit 59 and 61 Natural Gas Combustion Units Supporting NGCC System

Emission Unit	Description	Construction Commenced	Maximum Continuous Rating	Fuel
59	Auxiliary Boiler	Planned 2025	99.9 MMBtu/hr	Natural Gas
61	Fuel Gas (Dewpoint) Heater	Planned 2025	15 MMBtu/hr	Natural Gas

APPLICABLE REGULATIONS:
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 Emission Units 59 and 61, 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 Division 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 the Auxiliary Boiler (EU59) and Fuel Gas (Dewpoint) Heater (EU61) 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 13, 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)]

SECTION B - EMISSION UNITS, EMISSION POINTS, 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) 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)]

  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 (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

SECTION B - EMISSION UNITS, EMISSION POINTS, 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 63.7450(a)(12)]

h. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup. [40 CFR 63.7540(a)(13)]

i. 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)]

2. <u>Emissions Limitations:</u>

a. An affected facility shall not cause emissions of particulate matter in excess of 0.10 lb/MMBtu [401 KAR 59:015, Section 4(1)(b)]

b. An affected facility 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)]

c. An affected facility shall not cause emissions of sulfur dioxide in excess of 0.8 lb/MMBtu

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

[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.]

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 natural gas usage (MMscf) for Emission Units 59 and 61, on a monthly basis [401 KAR 52:020, Section 10; 40 CFR 60.48c(g)(2)].

5. Specific Recordkeeping Requirements:

a. The permittee shall maintain records of natural gas usage (MMscf) for Emission Units 59 and 61 on a monthly basis. [401 KAR 52:030, Section 10; 40 CFR 60.48c(g)(2)]

b. 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)]

c. 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)]

d. 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)]

e. 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)]

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

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 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. [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

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

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 this 40 CFR 63, 40 CFR 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). [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. The permittee shall submit each report in 40 CFR 63, Subpart DDDDD, Table 9 that applies. [40 CFR 63.7550(a)]

i. 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)]

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

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)]

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)]

j. 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)]

k. 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

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

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)]

l. The permittee shall submit notification of the date of construction or reconstruction and actual startup, as provided by 40 CFR 60.7. This notification shall include: [40 CFR 60.48c(a)]

   i. The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility. [40 CFR 60.48c(a)(1)]

m. See **Section F - Monitoring, Recordkeeping, and Reporting Requirements**

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

Emission Unit 62 NGCC Plant Cooling Tower

Emission Unit	Description	Construction Commenced	Maximum Operating Rate	Control Equipment
62	Mechanical Draft Cooling Tower (8 Cells)	Planned 2025	5.7 MMgal/hr	N/A (integrated drift eliminators)

APPLICABLE REGULATIONS:
401 KAR 59:010, *New process operations*.

1. **Operating Limitations:**
   a. The cooling towers shall be operated and maintained according to the manufacturer's specifications and recommendations at all times.

   b. The cooling tower shall be certified by the manufacturer to have a drift rate of 0.0005% or less.

   c. The use of chromium based water treatment chemicals in the cooling tower (EU62) is prohibited [To preclude 40 CFR 63, Subpart Q].

   Compliance Demonstration Method:
   Refer to subsections 5. Specific Recordkeeping Requirements

2. **Emission Limitations:**
   a. The opacity of visible emissions from each stack shall not equal or exceed 20 percent [401 KAR 59:010, Section 3(1)(a)].

   b. The following emission limitations for particulate matter are pursuant to 401 KAR 59:010, Section 3(2):

Process Rate (tons/hr)	Emission Limit (lbs/hr)
$P \leq 0.5$	$E = 2.34$
$0.5 < P \leq 30$	$E = 3.59P^{0.62}$
$P > 30$	$E = 17.31P^{0.16}$

   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.

3. **Testing Requirements:**
   Testing shall be conducted as required by the Cabinet. [401 KAR 50:045, Section 4]

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

4. Specific Monitoring Requirements:

a. 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]

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:

a. See **Section F – Monitoring, Recordkeeping, and Reporting Requirements**

7. Specific Control Equipment Operating Conditions:

a. The drift eliminators for the cooling tower 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.

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.[1]

	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 ~~Addittives~~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

[1] Certain insignificant activities will be shut down in conjunction with the shut down of the Unit 3 Boiler. However, they are being retained in Section C until after that event and will be reconciled as part of a subsequent permit renewal permit action.

SECTION C - INSIGNIFICANT ACTIVITIES

27. Fly Ash Transport	401 KAR 63:010
28. Gypsum Transport & Process Water System Solids	401 KAR 63:010

SECTION C - INSIGNIFICANT ACTIVITIES (CONTINUED)

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
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, 500 gallons~~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))	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 52:050
43. HVAC Heaters (Total Heat Input <10 MMBtu/hr)	None

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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)].

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.].

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.

SECTION G - GENERAL PROVISIONS (CONTINUED)

4. Construction, Start-Up, and Initial Compliance Demonstration Requirements

~~No construction authorized by this permit (V-17-030 R1).~~

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): EU58 (Unit 12 Gas Turbine with HRSG); EU60 (2 MW Diesel Emergency Generator); EU61 (Fuel Gas Dewpoint Heater); EU62 (Mechanical Draft Cooling Tower); EU63 (400 hp Diesel Driven Fire Pump), and associated insignificant activities.

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, with a copy to the Division's Frankfort Central Office, 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(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, 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.

SECTION G - GENERAL PROVISIONS (CONTINUED)

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 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;

SECTION G - GENERAL PROVISIONS (CONTINUED)

(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 82.166
(5) Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.
(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*.

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.

SECTION H - ALTERNATE OPERATING SCENARIOS

N/A

SECTION I - COMPLIANCE SCHEDULE

N/A

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].

SECTION J - ACID RAIN PERMIT (CONTINUED)

(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]

(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.

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].

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

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 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	
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**			

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