Kentucky Utilities Company

E. W. Brown Generating Station

Title V Permit Application Renewal
Submitted to Kentucky Division for Air Quality
July 2015

1.1 PURPOSE OF APPLICATION

Kentucky Utilities (KU) owns and operates the E.W. Brown Station in Burgin, Kentucky (near Harrodsburg, Kentucky). This electrical generating facility is classified as a major source under the Title V operating permit program and currently operates in accordance with permit V-10-004, issued by the Kentucky Division for Air Quality (KDAQ) on February 15, 2011. As the permit expires on February 15, 2016, a renewal application for the permit must be submitted at least six months prior to the permit expiration date, or by **August 15, 2015**. This application summary and associated forms constitutes the renewal application for the Brown Station required under Condition G (2) (a) of the existing permit.

1.2 SUMMARY OF APPLICATION CONTENTS

Following this introduction, a description of the operations at the Brown Station is provided in Section 2. Section 3 contains a summary of permit changes that have occurred since the last renewal permit was issued (Feb. 15, 2011).

A complete set of DEP7007 series application forms is provided in Appendix A. Supporting the application forms, a site plan and overview process flow diagram are provided in Appendix B and C, respectively. The basis of the emission factors and emission rates represented on the 7007N forms are fully documented in Appendix D.

2.1 FACILITY LOCATION

Brown Station is located approximately 25 miles southwest of Lexington and 9 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 B-1 in Appendix B shows the facility location and the surrounding area on a topographical map. The Universal Transverse Mercator (UTM) coordinates of the facility are (approximately) 701.2 kilometers (km) East and 4,184.9 km North (Zone 16, NAD83). Figure B-2 provides an overall site plan for Brown Station and Figure B-3 illustrates the locations of the major emission points. Figures B-4 and B-5 show aerial views of the main section of the facility where the three main utility boilers and combustion turbines are located.

2.2 FACILITY OPERATIONS SUMMARY

Brown Station is an electrical generating power plant that began operation in the 1950s. The primary emission units at the plant are three base load coal-fired utility boilers (Units 1, 2 & 3). Seven combustion turbines are also present that are used to provide peaking power. A process flow diagram depicting the defined emission units and air pollution control equipment is provided in Appendix C (Figure C-1).

2.2.1 UTILITY BOILERS

2.2.1.1 Generating Unit 1

Generating Units 1, 2, and 3 are each pulverized coal-fired utility boilers. Unit 1, which was constructed in 1957, is a dry bottom, wall-fired designed boiler with a heat input capacity of 1,260 MMBtu/hr and a net power output rating of approximately 102 MW. Unit 1 is equipped with low NO_X burners and an existing dry electrostatic precipitator (ESP). The Unit 1 exhaust stream combines with the exhaust from Units 2 and 3 before passing through the FGD system and out a combined stack (operational in 2010). (Refer to the process flow diagram in Appendix C.)

Because of the common ducting arrangement, should there be a malfunction that causes a trip of the Unit 1 ID fan, the exhaust duct from Unit 1 could be back-pressurized from Unit 2 and 3. To prevent this, in the event of a trip of the Unit 1 ID fan, the fuel feed to the boiler will be ceased, a damper will close in the Unit 1 exhaust duct, and an automated butterfly valve on a separate 36" diameter vent pipe installed between the Unit 1 ESP discharge and ID fan will open. This will allow for a natural draft of the atmosphere within the boiler to meet NFPA requirements.[1]

2.2.1.2 Generating Unit 2

Generating Unit 2 was constructed in 1963 and has a dry bottom, tangentially-fired boiler design with a heat input capacity of 1,733 MMBtu/hr and a net power output rating of approximately 169 MW. Similar to Unit 1, Unit 2 is equipped with low NO_X burners and a dry ESP. The exhaust from Unit 2 combines with Unit 1 and 3 and is routed to the FGD system and out the combined stack. After February 21, 2016, Unit 2 will not operate out of the existing Unit 2 bypass stack (MS002).

As is the case with Unit 1, in the event of a trip of the Unit 2 ID fan, a damper will close to isolate the Unit 2 exhaust duct from the combined duct to the common stack to prevent backpressure. The ductwork to the existing Unit 2/Unit 3 combined stack will be utilized to allow for the natural draft of the boiler to occur to meet NFPA requirements.[2]

2.2.1.3 Generating Unit 3

Generating Unit 3, constructed in 1971, is also a dry bottom, tangentially-fired boiler design but it much larger than either Unit 1 or 2. It has a heat input capacity of 5,300 MMBtu/hr and a net power output rating of approximately 433 MW. The exhaust passes through a Selective Catalytic Reduction (SCR) prior to the existing ESP (ESP will be replaced with a PJFF prior to Feb. 21, 2016). After passing through the ESP/PJFF, it combines with the exhaust from Units 1 and 2 before passing through the FGD system and out the single combined stack.

In the event of an ID fan trip, Unit 3 has two 48" diameter vent pipes with butterfly valves ran to provide an alternate vent path to allow natural drafting for Unit 3. The valves are located between the existing ESP/PJFF and the Unit 3 ID fans. In that instance, the discharge from these two valves will duct to the existing Unit 2/Unit 3 combined stack.

As noted in KU's Feb. 15, 2013 permit application, a pulse jet fabric filter system (PJFF) and a dry sorbent injection system using powered activated carbon (PAC), will be constructed and will replace the existing Unit 3 ESP. This project commenced in July of 2014 and will be completed prior to Feb. 21, 2016, the MATS extension date. The PJFF is needed to meet the new MATS requirements.

---

[1] National Fire Protection Association, Code 85, "Boiler and Combustion Systems Hazards", Paragraph 6.5.3.2.4.

[2] Ibid.

2.2.2 UTILITY BOILER SUPPORTING OPERATIONS

The supporting operations for the utility boilers at Brown Station include the (1) coal receiving, storage, conveying, and crushing operations, (2) bottom and fly ash handling systems, (3) a limestone receiving, storage, and processing system, (4) a gypsum dewatering system, and (5) three mechanical draft cooling towers.

2.2.2.1 Coal Handling and Processing System

Coal used as fuel in the Brown Station utility boilers is received at the site via rail car or trucks. The vast majority of the coal is received by rail car and is bottom loaded into one of two hoppers located under the railcar tracks– East Track Hopper or West Track Hopper. The coal is then conveyed to either an open storage pile or to a Crusher House. Coal delivered by truck can be dumped into one of the rail hoppers or directly to the outdoor storage pile. Coal is reclaimed from the pile via a screen over an underground hopper, from which the coal is conveyed to the Crusher House.

From the Crusher House, the coal is conveyed on a network of conveyors to the Traveling Tripper Conveyors located above the coal bunkers for each boiler. From the coal bunkers, the coal is fed into coal pulverizers and then into each boiler.

The use of enclosed conveyors minimizes the potential for fugitive dust emissions from the coal unloading, conveying, and transfer operations. The outdoor storage pile is also equipped with a wet suppression system that can be used when needed to control fugitive emissions. PM generated in the Crusher House is vented through a wet scrubbing system. PM emissions generated from the Traveling Tripper Conveyors serving the Unit 1 and 2 boilers are routed to a high efficiency cyclone, while PM emission streams from the two Traveling Tripper Conveyors serving Unit 3 are each routed individually to fabric filter systems.

2.2.2.2 Ash Handling System

Bottom ash generated in the utility boilers collects in boiler ash hoppers under each unit. Fly ash captured in the dry ESP & future PJFF, economizer, and air heaters is also collected in hoppers. The bottom and fly ash collected in these hoppers is currently sluiced (via water jet system) to the ash treatment basin on-site. Following installation of the new bottom ash and fly ash handling systems, bottom ash and fly ash will be collected in designated storage areas or silos. The material will then be transported to the to-be-built on-site landfill or distributed for beneficial reuse or off-site use.

2.2.2.3 Limestone Handling and Preparation

The forced oxidation FGD system is used to reduce SO_2 emissions from all three existing boilers. Limestone slurry is the reagent in the FGD system.

Limestone is received at the plant primarily by trucks and is unloaded at one of two truck dump stations. The limestone is conveyed from the truck dump hoppers up to a stacking tube located at the center of an outdoor storage pile. The stacking tube is a large diameter concrete column with openings at various heights to allow the limestone deposited to spill out of the stacking tube at the lowest opening just above the height of the storage pile. This design minimizes the fugitive emissions that would otherwise be created by dropping the limestone from a fixed height at the end of a conveyor.

Limestone is reclaimed from the outdoor storage pile via two screen openings, located on the bottom of the pile, which feed the limestone onto one of two conveyors. The reclaim conveyors transport the limestone to the top of the limestone processing building. Once transferred from the reclaim conveyors, the limestone is crushed in a wet grinding process and is mixed to the desired slurry consistency. The slurry is then stored in one of two tanks before being pumped as needed to the FGD system.

The processing of the limestone occurs entirely under roof and is a wet process. Therefore, the actual crushing and grinding operations are not a source of quantifiable emissions. PM emissions that may be released at the truck unloading stations will be captured and controlled by two fabric filter systems. The transfer point at the top of the stacking tube and the top of the two reclaim conveyors are equipped with fabric filters which greatly minimize potential PM emissions from this process.

2.2.2.4 Gypsum Dewatering and Placement Operation

The primary by-product of the FGD system is gypsum, a material that can be beneficially reused on-site as structural fill.

Currently, the gypsum slurry generated in the FGD system is piped to an enclosed dewatering facility on the north side of the ash basin. In the dewatering building, a vacuum filter belt removes excess water to reach a target free moisture content of approximately 15%. No screening, crushing or grinding operations are associated with the gypsum dewatering operation.

The dewatered gypsum cake is transferred from the vacuum filter belt to a conveyor/radial stacker and is temporarily stockpiled, typically for a period of not more than 4 days. During periods where the gypsum is not stockpiled, the material is piped directly into the ash treatment basin.

Following installation of the new gypsum handling systems, gypsum will be collected in a new designated storage area. The material will then be transported to the to-be-built on-site landfill or could be distributed for beneficial reuse or off-site use.

Based on the entrained moisture in the gypsum, no quantifiable fugitive particulate matter emissions are anticipated to result from this process.

2.2.2.5 Cooling Towers

Three mechanical draft cooling towers are used to dissipate heat to the atmosphere and recycle cooling water to each of the utility boilers (the Unit 3 cooling tower contains two modules). The heat is dissipated when the circulating water is sprayed into the cooling tower as a coarse mist, which then cascades down a fill material contacting the air passing up through the tower cells. As the circulating water falls, there is a transfer of heat from the water to the cooler atmospheric air.

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. Each cooling tower is equipped with a set of drift eliminators to minimize the amount of PM released.

2.2.3 PEAKING COMBUSTION TURBINES

Seven combustion turbines are located at the Brown Station. They are operated to provide peaking power. Four original turbines installed in the rnid-1990's (CT8, 9, 10 & 11) each have a permitted maximum heat input of 1,368 MMBtu/hr and can be fired on either natural gas or fuel oil. Two additional turbines installed in 1999 (CT6 & 7) have a permitted maximum heat input of 1,678 MMBtu/hr and are also fired on either natural gas or fuel oil. A seventh combustion turbine equipped to fire only natural gas installed in 2001 (CT5) accepted a maximum heat input of 1,368 MMBtu/hr but has a capacity of 1438 MMBtu/hr.

Each combustion turbine employs water injection for nitrogen oxides control. Each turbine exhausts out its own dedicated stack.

Date Submitted	Description	Approval
5/14/2014	Notification/502(b)(10) change - Replacement of coal crusher wet scrubber for Unit 16 (Section G notifications were submitted 11/14/2014 and 11/17/2014)	5/21/2014(APE20140008)
3/28/2014	New dry ash and gypsum disposal system. This includes the landfill operations and associated material transport operations and the dry material disposal system. Submittal also included a revised DEP7007DD form.	4/29/2014 (APE20140006)
3/25/2014	Construction of slipstream-scale CO2 capture system/Research project with University of Kentucky/Center for Applied Energy Research and others (#43 on Insignificant Activities list)	3/31/2014 (APE20140005)
3/19/2014	Notification - Use of Temporary SO3 Sorbent Material Injection System - Needed so that the existing sorbent silos (insignificant activity #20) can be relocated in prepare for the PJFF installation	Notification/Insignificant Activity
2/20/2014	Request to add two new emergency diesel generators. The Units are ID as 50 and 51 in the 2014 application; however, they are now being ID as Units 51 & 52. Revision #2 noted the New Ash Landfill Operations and Haul Trucks as Unit 50.	3/6/2014(APE20014004)
3/26/2013	Minor Revision for new dry material landfill operations. Revision #2 noted the New Ash Landfill Operations and Haul Trucks as Unit 50.	Added in revision 2 (V-10-004-R2)/ August 23, 2013
2/15/2013	Minor Revision to remove the Unit 3 ESP and install a PJFF and DSI; reason MATs compliance. The Section G 4(b)(1) notification of initial construction for the PJFF/DSI was submitted 9/23/14 and was noted as late reporting in the 2014 Annual Certification Report. Construction commenced 7/24/14.	Added in revision 2 (V-10-004-R2)/ August 23, 2013 APE20130001
7/31/2012	Revised DEP7007DD to include tanks (points 21-36) and corrections for 2, 5-8	8/14/2012(APE20120002) Note, changes were not included in the R2 issues in 2013
7/1/2011	Administrative change request to correct typos for Units 47-49	8/11/2011 email sent to KDAQ. Please note that Unit 49 in R2 is still incorrectly noted as a non-emergency engine. Unit 49 is an emergency engine.
12/7/2010	Off permit change request for Units 33 and 34 to clarify that the two Units share the same control/fabric filter	12/14/2010 (APE20100003); please note that the printed date on the KDAQ letter was October 8, 2010 (typo, the correct date was 12/14/2010)
7/30/2010	Revision to the 7/9/2009 Title V Application for the addition of a SCR Control for Unit 3; PSD synthetic minor permit limit for sulfuric acid mist	Added in V-10-004
6/7/2010	Minor permit mod for emergency generator (Unit 49) Tier II certified diesel engine	Added in V-10-004
5/25/2010	Request to replace COMS with PM CEMS for Units 1-3	Added in V-10-004

APPENDIX A – DEP7007 FORMS

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, Kentucky 40601
(502) 564-3999
http://www.air.ky.gov

DEP7007AI

Administrative Information

Enter if known
AFS Plant ID# *Source ID 21-167-00001 (AI 3148)*
Agency Use Only
Date Received
Log#
Permit#

PERMIT APPLICATION

The completion of this form is required under Regulations 401 KAR 52:020, 52:030, and 52:040 pursuant to KRS 224. Applications are incomplete unless accompanied by copies of all plans, specifications, and drawings requested herein. Failure to supply information required or deemed necessary by the division to enable it to act upon the application shall result in denial of the permit and ensuing administrative and legal action. Applications shall be submitted in triplicate.

1) APPLICATION INFORMATION

Note: The applicant must be the owner or operator. (The owner/operator may be individual(s) or a corporation.)

Name: *Kentucky Utilities Company – E.W. Brown Generating Station*

Title: *N/A* **Phone:** *(502) 627-2343*
(If applicant is an individual)

Mailing Address: Company *Kentucky Utilities Company*

Street or P.O. Box: *P.O. Box 32010*

City: *Louisville* **State:** *KY* **Zip Code:** *40232*

Is the applicant (check one): ☐ **Owner** ☐ **Operator** ☒ **Owner & Operator** ☐ **Corporation/LLC*** ☐ **LP****

* If the applicant is a Corporation or a Limited Liability Corporation, submit a copy of the current Certificate of Authority from the Kentucky Secretary of State.
** If the applicant is a Limited Partnership, submit a copy of the current Certificate of Limited Partnership from the Kentucky Secretary of State.

Person to contact for technical information relating to application:

Name: *Marlene Zeckner Pardee*

Title: *Senior Environmental Scientist* Phone: *(502) 627-2343*

2) OPERATOR INFORMATION

Note: The applicant must be the owner or operator. (The owner/operator may be individual(s) or a corporation.)

Name: *Same as applicant*

Title: ______ **Phone:** ______

Mailing Address: Company ______

Street or P.O. Box: ______

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

DEP7007AI
(Continued)

3) TYPE OF PERMIT APPLICATION

For new sources that currently *do not* hold *any* air quality permits in Kentucky and are required to obtain a permit prior to construction pursuant to 401 KAR 52:020, 52:030, or 52:040.

☐ Initial Operating Permit (the permit will authorize both construction and operation of the new source)

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

For existing sources that do not have a source-wide Operating Permit required by 401 KAR 52:020, 52:030, or 52:040.

Type of Source (*Check all that apply*): ☐ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

(*Check one only)*
☐ Initial Source-wide Operating Permit ☐ Construction of New Facilities at Existing Plant
☐ Construction of New Facilities at Existing Plant ☐ Modification of Existing Facilities at Existing Plant
☐ Other (explain) ______

For existing sources that currently have a source-wide Operating Permit.

Type of Source (*Check all that apply*): ☒ Major ☐ Conditional Major ☐ Synthetic Minor ☐ Minor

Current Operating Permit # *V-10-004 R2*

☐ **Administrative Revision** (describe type of revision requested, e.g. name change): ______

☒ **Permit Renewal** ☐ **Significant Revision** ☐ Minor Revision

☐ Addition of New Facilities ☐ Modification of Existing Facilities

For all construction and modification requiring a permit pursuant to 401 KAR 52:020, 52:030, or 52:040.

Proposed Date for Start of Construction or Modification: ______ Proposed date for Operation Start-up: ______

4) SOURCE INFORMATION

Source Name: *Kentucky Utilities Company - E.W. Brown Generating Station*

Source Street Address: *815 Dix Dam Road*

City: *Harrodsburg* **Zip Code:** *40330* **County:** *Mercer*

Primary Standard Industrial Classification (SIC) Category: *Generation & Transmission of Electricity* **Primary SIC #:** *4911*

Property Area (Acres or Square Feet): *1222.1 acres* **Number of Employees:** *~148*

Description of Area Surrounding Source (*check one*):
☐ Commercial Area ☐ Residential Area ☐ Industrial Area ☐ Industrial Park ☒ Rural Area ☐ Urban Area

Approximate Distance to Nearest Residence or Commercial Property: *~200 feet*

UTM <u>or</u> Standard Location Coordinates: (*Include topographical map showing property boundaries*)

UTM Coordinates: Zone *16* Horizontal (km) *701.2* Vertical (km) *4184.9*

Standard Coordinates: Latitude ______ Degrees ______ Minutes ______ Seconds

Longitude ______ Degrees ______ Minutes ______ Seconds

DEP7007AI
(Continued)

4) SOURCE INFORMATION (CONTINUED)

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

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

KPDES Permit No. KY0002020,

Kentucky Division of Waste Management Certification of Registration – EPA ID No. KYD-000-622-951

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

5) OTHER REQUIRED INFORMATION

Indicate the type(s) and number of forms attached as part of this application.

10	DEP7007A	Indirect Heat Exchanger, Turbine, Internal Combustion Engine	___	DEP7007R	Emission Reduction Credit
1	DEP7007B	Manufacturing or Processing Operations	___	DEP7007S	Service Stations
___	DEP7007C	Incinerators & Waste Burners	___	DEP7007T	Metal Plating & Surface Treatment Operations
___	DEP7007F	Episode Standby Plan	1	DEP7007V	Applicable Requirements & Compliance Activities
___	DEP7007J	Volatile Liquid Storage	1	DEP7007Y	Good Engineering Practice (GEP) Stack Height Determination
___	DEP7007K	Surface Coating or Printing Operations	___	DEP7007AA	Compliance Schedule for Noncomplying Emission Units
?	DEP7007L	Concrete, Asphalt, Coal, Aggregate, Feed, Corn, Flour, Grain, & Fertilizer	___	DEP7007BB	Certified Progress Report
___	DEP7007M	Metal Cleaning Degreasers	*	DEP7007CC	Compliance Certification **See January 2015 Annual Compliance Certification for 2014*
1	DEP7007N	Emissions, Stacks, and Controls Information	1	DEP7007DD	Insignificant Activities
___	DEP7007P	Perchloroethylene Dry Cleaning Systems			

Check other attachments that are part of this application.

Required Data	Supplemental Data
☒ Map or Drawing Showing Location	☐ Stack Test Report
☒ Process Flow Diagram and Description	☐ Certificate of Authority from the Secretary of State (for Corporations and Limited Liability Companies)
☒ Site Plan Showing Stack Data and Locations	☐ Certificate of Limited Partnership from the Secretary of State (for Limited Partnerships)
☒ Emission Calculation Sheets	☐ Claim of Confidentiality (See 400 KAR 1:060)
☐ Material Safety Data Sheets (MSDS)	☐ Other (Specify) ____________

Indicate if you expect to emit, in any amount, hazardous or toxic materials or compounds or such materials into the atmosphere from any operation or process at this location.

☒ Pollutants regulated under 401 KAR 57:002 (NESHAP)   ☒ Pollutants listed in 401 KAR 63:060 (HAPS)

☒ Pollutants listed in 40 CFR 68 Subpart F [112(r) pollutants]   ☐ Other

Has your company filed an emergency response plan with local and/or state and federal officials outlining the measures that would be implemented to mitigate an emergency release?

☒ Yes ☐ No

Check whether your company is seeking coverage under a permit shield. If "Yes" is checked, applicable requirements must be identified on Form DEP7007V. Identify any non-applicable requirements for which you are seeking permit shield coverage on a separate attachment to the application.

☒ Yes ☐ No ☐ A list of non-applicable requirements is attached

DEP7007AI
(Continued)

6) OWNER INFORMATION

Note: If the applicant is the owner, write "same as applicant" on the name line.

Name: *Same as applicant*

Title: ______ **Phone:** ______

Mailing Address: ______
Company

Street or P.O. Box: ______

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

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

Name	Position (owner, partner, president, CEO, treasurer, etc.)
None	

(attach another sheet if necessary)

7) 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: Ralph Bowling (Authorized Signature) 7-10-15 (Date)

Ralph Bowling
(Typed or Printed Name of Signatory)

Vice President Power Production
(Title of Signatory)

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 017
Emission Unit # 01

1) **Type of Unit (Make, Model, Etc.):** Babcock & Wilcox Pulverized Coal Boiler

Date Installed: 5/1/1957 **Cost of Unit:** $2.7 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 1

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** X
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,260
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

X **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** _ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): No. 2 Fuel Oil (Startup and Stabilization Only)

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	20%	3.8%	11,000 Btu/lb	11,000 Btu/lb
Secondary	0.0001	0.0015%	NA	138 MMbtu/Mgal

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__ hours/day   _______ days/week   _______ weeks/year

9) If this unit is multipurpose, describe percent in each use category:

Space Heat _________%   Process Heat ____________ %   Power __________ %

10) Control options for turbine/IC engine (C*heck*)

- __ (1) Water Injection
- __ (2) Steam Injection
- __ (3) Selective Catalytic Reduction (SCR)
- __ (3) Non-Selective Catalytic Reduction (NSCR)
- __ (5) Combustion Modification)
- __ (5) Other (*Specify*) ____________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

__X______ Pulverized Coal Fired:

X Dry Bottom   X Wall Fired
__ Wet Bottom   __ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

__________ Cyclone Furnace

__________ Overfeed Stoker

__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

________ Spreader Stoker

________ Underfeed Stoker

________ Hand-fed

________ Other (*specify*) __________________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired   ________ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven   ________ Stoker   ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) Combustion Air **Draft:** ________ **Natural** ___X___ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) ___15-40___ **%**

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☒ **Yes** ☐ **No**
B. If yes, are they located in accordance with 40 CFR 60*? ☒ **Yes** ☐ **No**
C. List other units vented to this stack Units 2 & 3

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Coal Handling System – Coal is shipped to the site in unit trains and/or trucks. Coal is unloaded at a maximum rate of 1,640 tons per hour. The coal is either diverted to an open storage pile or it is transferred via conveyor to a crusher house. The crushed coal is then conveyed to coal storage bunkers for feed into the coal-fired unit's pulverizers. Coal can be reclaimed from the open storage pile into the crusher house, so it can then proceed through the coal handling system. The coal handling system is equipped with dust collectors and there is the capacity for wet suppression on the open coal pile necessary to control fugitive emissions.

Ash Handling System – Both bottom and fly ash residual are created from the combustion of coal. Bottom ash falls to the bottom of the boiler where it is collected in the boiler ash hoppers. Fly ash is captured in the ESP, the economizer and the air heater and is collected in each of these places through a hopper system. The ash (bottom and fly) collected in each of these hoppers is then sluiced (via water jet system) to the ash treatment basin on site (a surface impoundment with a KPDES permitted outfall). Fly ash captured in the ESP can be collected by a dry ash handling system for beneficial reuse.

Gypsum Handling System - The primary byproduct of the FGD system will be gypsum. Gypsum can be a saleable product if it meets certain quality characteristics. It is anticipated that the gypsum will meet these quality standards; hence a new gypsum dewatering facility will be constructed at Brown. The gypsum slurry will be pumped from the FGD to the dewatering facility to be processed for off-site users. It will then be conveyed to a new exterior storage pile. A portion of the gypsum product may serve as beneficial re-use for the construction of the Brown ash pond. From the storage pile, the gypsum will be conveyed to a new truck loading station or onto an adjacent rail car loading station. In event the gypsum cannot be marketed, the gypsum will be conveyed to the on-site ash pond. Based on the entrained moisture in the gypsum, fugitive dust emissions from this process are anticipated to be nonexistent.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DEP7007A

INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

Emission Point # 017

Emission Unit # 02

1) **Type of Unit (Make, Model, Etc.):** Combustion Engineering Pulverized Coal Boiler

Date Installed: 6/1/1963 **Cost of Unit:** $4.6 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 2

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** X
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,733
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

X **A. Coal** ____ **B. Fuel Oil #** ***(C****heck one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** _ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): No. 2 Fuel Oil (Startup and Stabilization Only)

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	20%	3.8%	11,000 Btu/lb	11,000 Btu/lb
Secondary	**0.0001**	**0.0015%**	**NA**	**138Mmbtu/Mgal**

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

_ hours/day _______ days/week _______ weeks/year

9) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% Process Heat ____________ % Power __________ %

10) Control options for turbine/IC engine (Check)

__ (1) Water Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (5) Combustion Modification)
__ (2) Steam Injection
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Other (Specify) ____________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

X Pulverized Coal Fired:

X Dry Bottom __ Wall Fired
__ Wet Bottom X Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

__________ Cyclone Furnace

__________ Overfeed Stoker

__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

________ Spreader Stoker

________ Underfeed Stoker

________ Hand-fed

________ Other (*specify*) __________________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired ________ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven ________ Stoker ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** Draft: ________ Natural ___X___ Induced

Forced Pressure __________ lbs/sq. in.

Percent excess air (air supplied in excess of theoretical air) ___15-40___ %

SECTION III

16) **Additional Stack Data**

A. Are sampling ports provided? ☒ Yes ☐ No
B. If yes, are they located in accordance with 40 CFR 60*? ☒ Yes ☐ No
C. List other units vented to this stack ___Units 1 & 3___

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Coal Handling System – Coal is shipped to the site in unit trains and/or trucks. Coal is unloaded at a maximum rate of 1,640 tons per hour. The coal is either diverted to an open storage pile or it is transferred via conveyor to a crusher house. The crushed coal is then conveyed to coal storage bunkers for feed into the coal-fired unit's pulverizers. Coal can be reclaimed from the open storage pile into the crusher house, so it can then proceed through the coal handling system. The coal handling system is equipped with dust collectors and there is the capacity for wet suppression on the open coal pile necessary to control fugitive emissions.

Ash Handling System – Both bottom and fly ash residual are created from the combustion of coal. Bottom ash falls to the bottom of the boiler where it is collected in the boiler ash hoppers. Fly ash is captured in the ESP, the economizer and the air heater and is collected in each of these places through a hopper system. The ash (bottom and fly) collected in each of these hoppers is then sluiced (via water jet system) to the ash treatment basin on site (a surface impoundment with a KPDES permitted outfall). Fly ash captured in the ESP can be collected by a dry ash handling system for beneficial reuse.

Gypsum Handling System - The primary byproduct of the FGD system will be gypsum. Gypsum can be a saleable product if it meets certain quality characteristics. It is anticipated that the gypsum will meet these quality standards; hence a new gypsum dewatering facility will be constructed at Brown. The gypsum slurry will be pumped from the FGD to the dewatering facility to be processed for off-site users. It will then be conveyed to a new exterior storage pile. A portion of the gypsum product may serve as beneficial re-use for the construction of the Brown ash pond. From the storage pile, the gypsum will be conveyed to a new truck loading station or onto an adjacent rail car loading station. In event the gypsum cannot be marketed, the gypsum will be conveyed to the on-site ash pond. Based on the entrained moisture in the gypsum, fugitive dust emissions from this process are anticipated to be nonexistent.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 017
Emission Unit # 03

1) **Type of Unit (Make, Model, Etc.):** Combustion Engineering Pulverized Coal Boiler

Date Installed: 7/19/1971 **Cost of Unit:** $16.5 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 3

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** X
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 5,300
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

X **A. Coal** ____ **B. Fuel Oil #** ***(****Check one***)** ____ 1 ____ **2** ____ **3** ____ **4** ____ **5** ____ **6**

____ **C. Natural Gas** _ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): No. 2 Fuel Oil (Startup and Stabilization Only)

5) **Fuel Composition**

Type	Percent Ash[a] Maximum	Percent Sulfur[b] Maximum	Heat Content Corresponding to: [c, d] Maximum Ash	Maximum Sulfur
Primary	20%	3.8%	11,000 Btu/lb	11,000 Btu/lb
Secondary	**0.0001**	**0.0015%**	**NA**	**138 MMbtu/Mgal**

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__ hours/day ________ days/week ________ weeks/year

9) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% Process Heat ____________ % Power __________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (5) Combustion Modification)
__ (2) Steam Injection
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Other (*Specify*) ____________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

__X__ Pulverized Coal Fired:

X Dry Bottom
__ Wet Bottom
__ Wall Fired
X Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

__________ Cyclone Furnace
__________ Overfeed Stoker
__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed
________ Spreader Stoker
________ Underfeed Stoker
________ Hand-fed
________ Other (*specify*) __________________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired ________ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven ________ Stoker ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) Combustion Air **Draft:** ________ **Natural** __X__ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __15-40__ **%**

SECTION III

16) Additional Stack Data

A. **Are sampling ports provided?** ☒ **Yes** ☐ **No**
B. **If yes, are they located in accordance with 40 CFR 60*?** ☒ **Yes** ☐ **No**
C. **List other units vented to this stack** __Units 1 & 2__

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Coal Handling System – Coal is shipped to the site in unit trains and/or trucks. Coal is unloaded at a maximum rate of 1,640 tons per hour. The coal is either diverted to an open storage pile or it is transferred via conveyor to a crusher house. The crushed coal is then conveyed to coal storage bunkers for feed into the coal-fired unit's pulverizers. Coal can be reclaimed from the open storage pile into the crusher house, so it can then proceed through the coal handling system. The coal handling system is equipped with dust collectors and there is the capacity for wet suppression on the open coal pile necessary to control fugitive emissions.

Ash Handling System – Both bottom and fly ash residual are created from the combustion of coal. Bottom ash falls to the bottom of the boiler where it is collected in the boiler ash hoppers. Fly ash is captured in the ESP, the economizer and the air heater and is collected in each of these places through a hopper system. The ash (bottom and fly) collected in each of these hoppers is then sluiced (via water jet system) to the ash treatment basin on site (a surface impoundment with a KPDES permitted outfall). Fly ash captured in the ESP can be collected by a dry ash handling system for beneficial reuse.

Gypsum Handling System - The primary byproduct of the FGD system will be gypsum. Gypsum can be a saleable product if it meets certain quality characteristics. It is anticipated that the gypsum will meet these quality standards; hence a new gypsum dewatering facility will be constructed at Brown. The gypsum slurry will be pumped from the FGD to the dewatering facility to be processed for off-site users. It will then be conveyed to a new exterior storage pile. A portion of the gypsum product may serve as beneficial re-use for the construction of the Brown ash pond. From the storage pile, the gypsum will be conveyed to a new truck loading station or onto an adjacent rail car loading station. In event the gypsum cannot be marketed, the gypsum will be conveyed to the on-site ash pond. Based on the entrained moisture in the gypsum, fugitive dust emissions from this process are anticipated to be nonexistent.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 23
Emission Unit # 23

1) **Type of Unit (Make, Model, Etc.):** Asea Brown Boveria model GT11N2

Date Installed: 11/28/1995 **Cost of Unit:** $18.7 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Combustion Turbine #9 (CT9)

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** X
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) **2-cycle lean burn** ____
   (b) **4-cycle lean burn** ____
   (c) **4-cycle rich burn** ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,368 @ ISO Standard Conditions
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** X **B. Fuel Oil #** *(Check one)* ____ 1 X 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** __ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): Natural Gas

5) **Fuel Composition**

Type	Percent Ash[a] Maximum	Percent Sulfur[b] Maximum	Heat Content Corresponding to:[c, d] Maximum Ash	Heat Content Corresponding to:[c, d] Maximum Sulfur
Primary	<0.01%	0.05%	138 MMBtu/Mgal	138 MMBtu/Mgal
Secondary	Trace	0.05 gr/100 ft³	1,020 Btu/scf	1,020 Btu/scf

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day __*__ days/week __*__ weeks/year

* The maximum operating hours for each CT shall not exceed 2,500 hours per year based on a twelve-month rolling total **when combusting fuel oil** (please see **Appendix G)**

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat ___________ % Power _________ %

10) Control options for turbine/IC engine (*Check*)

_X_ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ___________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

_________ Pulverized Coal Fired:

__ Dry Bottom **__ Wall Fired**
__ Wet Bottom **__ Tangentially Fired**

Fly Ash Rejection: ☐ **Yes** ☐ **No**

_________ Cyclone Furnace

_______ Spreader Stoker

_________ Overfeed Stoker

_______ Underfeed Stoker

_________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

_______ Hand-fed

_______ Other (*specify*) _______________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired

_______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ **Yes** ☐ **No**

_______ Dutch Oven/Fuel Cell Oven **_______ Stoker** **_______ Suspension Firing**

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ **Yes** ☐ **No**

__ Flue Gas Recirculation: ☐ **Yes** ☐ **No**

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

**DEP7007A
(Continued)**

15) Combustion Air Draft: ________ Natural ________ Induced

Forced Pressure __________ lbs/sq. in.

Percent excess air (air supplied in excess of theoretical air) __________ %

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☒ **Yes** ☐ **No**
B. If yes, are they located in accordance with 40 CFR 60*? ☒ **Yes** ☐ **No**
C. List other units vented to this stack *None*

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Fuel Oil Handling System –Fuel oil is primarily received by tanker trucks, although rail tanker cars can also be accommodated at the site. Dual-duty (truck/rail) transfer stations unload the fuel oil to one of two 1.1 million gallon storage tanks. There are six rail/truck fuel oil unloading stations, each equipped with 400 gpm transfer pumps. All connections are sealed to prevent vapor release. Next, a recirculating fuel oil pumping system forwards fuel from the storage tanks to the combustion turbine fuel oil delivery blocks for metering and injection into the turbines.

Natural Gas Handling System – Natural gas is supplied from either of two natural gas transmission companies' line taps to separate metering stations that feed a 20 inch diameter pipeline extending approximately 11 miles to the site. In addition, a compressor station at the supply tabs provides additional gas storage within the pipeline to accommodate high demand flowrates. A regulator station located at the site distributes gas to the fuel delivery block for each turbine.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

*(Submit copies of this form for each individual unit.
Make additional copies as needed)*

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 24
Emission Unit # 24

1) **Type of Unit (Make, Model, Etc.):** Asea Brown Boveria Model GT11N2

Date Installed: 12/22/1995 **Cost of Unit:** $18.2 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Combustion Turbine #10 (CT10)

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** X
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,368 @ ISO Standard Conditions
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** X **B. Fuel Oil #** (*Check one*) ____ 1 X 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): Natural Gas

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	<0.01%	0.05%	138 MMbtu/Mgal	138 MMbtu/Mgal
Secondary	Trace	0.05 gr/100 ft^3	1,020 Btu/scf	1,020 Btu/scf

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ **hours/day** __*__ **days/week** __*__ **weeks/year**

* The maximum operating hours for each CT shall not exceed 2,500 hours per year based on a twelve-month rolling total **when combusting fuel oil** (please see **Appendix G)**

9) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% Process Heat ____________ % Power __________ %

10) Control options for turbine/IC engine (C*heck*)

_X_ (1) Water Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (5) Combustion Modification)
__ (2) Steam Injection
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Other (*Specify*) ____________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

__________ Pulverized Coal Fired:

__ Dry Bottom __ Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection:

☐ Yes ☐ No

__________ Cyclone Furnace

________ Spreader Stoker

__________ Overfeed Stoker

________ Underfeed Stoker

__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

________ Hand-fed

________ Other (*specify*) __________________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired

________ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven ________ Stoker ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

A. **Are sampling ports provided?** ☒ **Yes** ☐ **No**

B. **If yes, are they located in accordance with 40 CFR 60*?** ☒ **Yes** ☐ **No**

C. **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Fuel Oil Handling System –Fuel oil is primarily received by tanker trucks, although rail tanker cars can also be accommodated at the site. Dual-duty (truck/rail) transfer stations unload the fuel oil to one of two 1.1 million gallon storage tanks. There are six rail/truck fuel oil unloading stations, each equipped with 400 gpm transfer pumps. All connections are sealed to prevent vapor release. Next, a recirculating fuel oil pumping system forwards fuel from the storage tanks to the combustion turbine fuel oil delivery blocks for metering and injection into the turbines.

Natural Gas Handling System – Natural gas is supplied from either of two natural gas transmission companies' line taps to separate metering stations that feed a 20 inch diameter pipeline extending approximately 11 miles to the site. In addition, a compressor station at the supply tabs provides additional gas storage within the pipeline to accommodate high demand flowrates. A regulator station located at the site distributes gas to the fuel delivery block for each turbine.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit.
Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 25
Emission Unit # 25

1) **Type of Unit (Make, Model, Etc.):** Asea Brown Boveria Model GT11N2

Date Installed: 3/1/1996 **Cost of Unit:** $18.3 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Combustion Turbine #8 (CT8)

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** X
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,368 @ ISO Standard Conditions
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** X **B. Fuel Oil #** (*Check one*) ____ 1 X 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): Natural Gas

5) **Fuel Composition**

Type	Percent Ash[a] Maximum	Percent Sulfur[b] Maximum	Heat Content Corresponding to:[c, d] Maximum Ash	Maximum Sulfur
Primary	<0.01%	0.05%	138 MMBtu/Mgal	138 MMBtu/Mgal
Secondary	Trace	0.05 gr/100 ft³	1,020 Btu/scf	1,020 Btu/scf

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units***)*: N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ **hours/day** __*__ **days/week** __*__ **weeks/year**

* The maximum operating hours for each CT shall not exceed 2,500 hours per year based on a twelve-month rolling total **when combusting fuel oil** (please see **Appendix G)**

9) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% **Process Heat ____________ %** **Power __________ %**

10) Control options for turbine/IC engine (*Check*)

_X_ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ____________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

__________ Pulverized Coal Fired:

__ Dry Bottom **__ Wall Fired**
__ Wet Bottom **__ Tangentially Fired**

Fly Ash Rejection:

☐ **Yes** ☐ **No**

__________ Cyclone Furnace

________ Spreader Stoker

__________ Overfeed Stoker

________ Underfeed Stoker

__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

________ Hand-fed

________ Other (*specify*) __________________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired **________ Horizontally Opposed (Normal) Fired**

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ **Yes** ☐ **No**

_______ Dutch Oven/Fuel Cell Oven **________ Stoker** **________ Suspension Firing**

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ **Yes** ☐ **No**

__ Flue Gas Recirculation: ☐ **Yes** ☐ **No**

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) Combustion Air **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☒ **Yes** ☐ **No**
B. If yes, are they located in accordance with 40 CFR 60*? ☒ **Yes** ☐ **No**
C. List other units vented to this stack *None*

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Fuel Oil Handling System –Fuel oil is primarily received by tanker trucks, although rail tanker cars can also be accommodated at the site. Dual-duty (truck/rail) transfer stations unload the fuel oil to one of two 1.1 million gallon storage tanks. There are six rail/truck fuel oil unloading stations, each equipped with 400 gpm transfer pumps. All connections are sealed to prevent vapor release. Next, a recirculating fuel oil pumping system forwards fuel from the storage tanks to the combustion turbine fuel oil delivery blocks for metering and injection into the turbines.

Natural Gas Handling System – Natural gas is supplied from either of two natural gas transmission companies' line taps to separate metering stations that feed a 20 inch diameter pipeline extending approximately 11 miles to the site. In addition, a compressor station at the supply tabs provides additional gas storage within the pipeline to accommodate high demand flowrates. A regulator station located at the site distributes gas to the fuel delivery block for each turbine.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(*Submit copies of this form for each individual unit. Make additional copies as needed)*

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 26
Emission Unit # 26

1) **Type of Unit (Make, Model, Etc.):** Asea Brown Boveria Model GT11N2

Date Installed: 5/8/96 **Cost of Unit:** $18.4 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Combustion Turbine #11 (CT11)

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** X
3. **Pipe Line Compressor Engines:**
   - ____ **Gas Turbine**
   - ____ **Reciprocating engines**
     - **(a) 2-cycle lean burn** ____
     - **(b) 4-cycle lean burn** ____
     - **(c) 4-cycle rich burn** ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,368 @ ISO Standard Conditions
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** X **B. Fuel Oil #** (*Check one*) ____ 1 X 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** __ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): Natural Gas

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	<0.01%	0.05%	138 MMBtu/Mgal	138 MMBtu/Mgal
Secondary	Trace	0.05 gr/100 ft^3	1,020 Btu/scf	1,020 Btu/scf

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units)*:*** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ **hours/day** __*__ **days/week** __*__ **weeks/year**

* The maximum operating hours for each CT shall not exceed 2,500 hours per year based on a twelve-month rolling total **when combusting fuel oil** (please see **Appendix G)**

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% **Process Heat** ___________ % **Power** _________ %

10) Control options for turbine/IC engine (*Check*)

_X_ **(1) Water Injection**
__ **(2) Steam Injection**
__ **(3) Selective Catalytic Reduction (SCR)**
__ **(3) Non-Selective Catalytic Reduction (NSCR)**
__ **(5) Combustion Modification)**
__ **(5) Other (*Specify*)** ___________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

_________ **Pulverized Coal Fired:**

__ **Dry Bottom** __ **Wall Fired**
__ **Wet Bottom** __ **Tangentially Fired**

Fly Ash Rejection: ☐ **Yes** ☐ **No**

_________ **Cyclone Furnace**
_______ **Spreader Stoker**
_________ **Overfeed Stoker**
_______ **Underfeed Stoker**
_________ **Fluidized Bed Combustor:**
_______ **Circulating Bed**
_______ **Bubbling Bed**
_______ **Hand-fed**
_______ **Other (*specify*)** _______________________

12) Oil-Fired Unit

_______ **Tangentially (Corner) Fired** _______ **Horizontally Opposed (Normal) Fired**

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ **Yes** ☐ **No**

_______ **Dutch Oven/Fuel Cell Oven** _______ **Stoker** _______ **Suspension Firing**

_______ **Fluidized Bed Combustion (FBC)**

14) Natural Gas-Fired Units

__ **Low NO_x Burners:** ☐ **Yes** ☐ **No**

__ **Flue Gas Recirculation:** ☐ **Yes** ☐ **No**

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

A. **Are sampling ports provided?** ☒ **Yes** ☐ **No**
B. **If yes, are they located in accordance with 40 CFR 60*?** ☒ **Yes** ☐ **No**
C. **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Fuel Oil Handling System –Fuel oil is primarily received by tanker trucks, although rail tanker cars can also be accommodated at the site. Dual-duty (truck/rail) transfer stations unload the fuel oil to one of two 1.1 million gallon storage tanks. There are six rail/truck fuel oil unloading stations, each equipped with 400 gpm transfer pumps. All connections are sealed to prevent vapor release. Next, a recirculating fuel oil pumping system forwards fuel from the storage tanks to the combustion turbine fuel oil delivery blocks for metering and injection into the turbines.

Natural Gas Handling System – Natural gas is supplied from either of two natural gas transmission companies' line taps to separate metering stations that feed a 20 inch diameter pipeline extending approximately 11 miles to the site. In addition, a compressor station at the supply tabs provides additional gas storage within the pipeline to accommodate high demand flowrates. A regulator station located at the site distributes gas to the fuel delivery block for each turbine.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

Emission Point # 27
Emission Unit # 27

1) **Type of Unit (Make, Model, Etc.):** Asea Brown Boveria Model GT24AB

Date Installed: 8/11/1999 **Cost of Unit:** $60.561 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Combustion Turbine #6 (CT6)

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** X
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) **2-cycle lean burn** ____
   (b) **4-cycle lean burn** ____
   (c) **4-cycle rich burn** ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,678 @ ISO Standard Conditions
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** X **B. Fuel Oil #** (*Check one*) ____ 1 X 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** __ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): Natural Gas

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	<0.01%	0.05%	138 MMBtu/Mgal	138 MMBtu/Mgal
Secondary	Trace	0.05 gr/100 ft³	1,020 Btu/scf	1,020 Btu/scf

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units***)***:** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ **hours/day** __*__ **days/week** __*__ **weeks/year**

* The maximum operating hours for each CT shall not exceed 2,500 hours per year based on a twelve-month rolling total **when combusting fuel oil** (please see **Appendix G)**

9) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% **Process Heat** ____________ % **Power** __________ %

10) Control options for turbine/IC engine (*Check*)

_X_ **(1) Water Injection**
__ **(2) Steam Injection**
__ **(3) Selective Catalytic Reduction (SCR)**
__ **(3) Non-Selective Catalytic Reduction (NSCR)**
__ **(5) Combustion Modification)**
__ **(5) Other (*Specify*)** ____________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

__________ **Pulverized Coal Fired:**

__ **Dry Bottom** __ **Wall Fired**
__ **Wet Bottom** __ **Tangentially Fired**

Fly Ash Rejection: ☐ **Yes** ☐ **No**

__________ **Cyclone Furnace**

________ **Spreader Stoker**

__________ **Overfeed Stoker**

________ **Underfeed Stoker**

__________ **Fluidized Bed Combustor:**
_______ **Circulating Bed**
_______ **Bubbling Bed**

________ **Hand-fed**

________ **Other (*specify*)** __________________________

12) Oil-Fired Unit

_______ **Tangentially (Corner) Fired** ________ **Horizontally Opposed (Normal) Fired**

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ **Yes** ☐ **No**

_______ **Dutch Oven/Fuel Cell Oven** ________ **Stoker** ________ **Suspension Firing**

_______ **Fluidized Bed Combustion (FBC)**

14) Natural Gas-Fired Units

__ **Low NO_x Burners:** ☐ **Yes** ☐ **No**

__ **Flue Gas Recirculation:** ☐ **Yes** ☐ **No**

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) Combustion Air **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☒ **Yes** ☐ **No**
B. If yes, are they located in accordance with 40 CFR 60*? ☒ **Yes** ☐ **No**
C. List other units vented to this stack *None*

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Fuel Oil Handling System –Fuel oil is primarily received by tanker trucks, although rail tanker cars can also be accommodated at the site. Dual-duty (truck/rail) transfer stations unload the fuel oil to one of two 1.1 million gallon storage tanks. There are six rail/truck fuel oil unloading stations, each equipped with 400 gpm transfer pumps. All connections are sealed to prevent vapor release. Next, a recirculating fuel oil pumping system forwards fuel from the storage tanks to the combustion turbine fuel oil delivery blocks for metering and injection into the turbines.

Natural Gas Handling System – Natural gas is supplied from either of two natural gas transmission companies' line taps to separate metering stations that feed a 20 inch diameter pipeline extending approximately 11 miles to the site. In addition, a compressor station at the supply tabs provides additional gas storage within the pipeline to accommodate high demand flowrates. A regulator station located at the site distributes gas to the fuel delivery block for each turbine.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 28
Emission Unit # 28

1) **Type of Unit (Make, Model, Etc.):** Asea Brown Boveria Model GT24AB

Date Installed: 8/8/1999 **Cost of Unit:** $60.138 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Combustion Turbine #7 (CT7)

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** X
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** 1,678 @ ISO Standard Conditions
2. **Power output (hp):** ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** X **B. Fuel Oil #** (*Check one*) ____ 1 X 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): Natural Gas

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	<0.01%	0.05%	138 MMBtu/Mgal	138 MMBtu/Mgal
Secondary	Trace	0.05 gr/100 ft^3	1,020 Btu/scf	1,020 Btu/scf

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*	
__*__ **hours/day** __*__ **days/week** __*__ **weeks/year**	
* The maximum operating hours for each CT shall not exceed 2,500 hours per year based on a twelve-month rolling total **when combusting fuel oil** (please see **Appendix G)**	
9) If this unit is multipurpose, describe percent in each use category:	
Space Heat ____% **Process Heat** ____ % **Power** ____ %	
10) Control options for turbine/IC engine (*Check*)	
_X_ **(1) Water Injection**	__ **(2) Steam Injection**
__ **(3) Selective Catalytic Reduction (SCR)**	__ **(3) Non-Selective Catalytic Reduction (NSCR)**
__ **(5) Combustion Modification)**	__ **(5) Other (*Specify*)** ____
IMPORTANT: Form DEP7007N must also be completed for this unit.	
SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS	
11) Coal-Fired Units	
____ **Pulverized Coal Fired:**	**Fly Ash Rejection:**
__ **Dry Bottom** __ **Wall Fired**	☐ **Yes** ☐ **No**
__ **Wet Bottom** __ **Tangentially Fired**	
____ **Cyclone Furnace**	____ **Spreader Stoker**
____ **Overfeed Stoker**	____ **Underfeed Stoker**
____ **Fluidized Bed Combustor:**	____ **Hand-fed**
____ **Circulating Bed**	
____ **Bubbling Bed**	____ **Other (*specify*)** ____
12) Oil-Fired Unit	
____ **Tangentially (Corner) Fired**	____ **Horizontally Opposed (Normal) Fired**
13) Wood-Fired Unit	
Fly-Ash Reinjection: ☐ **Yes** ☐ **No**	
____ **Dutch Oven/Fuel Cell Oven** ____ **Stoker**	____ **Suspension Firing**
____ **Fluidized Bed Combustion (FBC)**	
14) Natural Gas-Fired Units	
__ **Low NO_x Burners:** ☐ **Yes** ☐ **No**	
__ **Flue Gas Recirculation:** ☐ **Yes** ☐ **No**	

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) Combustion Air **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☒ **Yes** ☐ **No**
B. If yes, are they located in accordance with 40 CFR 60*? ☒ **Yes** ☐ **No**
C. List other units vented to this stack *None*

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Fuel Oil Handling System –Fuel oil is primarily received by tanker trucks, although rail tanker cars can also be accommodated at the site. Dual-duty (truck/rail) transfer stations unload the fuel oil to one of two 1.1 million gallon storage tanks. There are six rail/truck fuel oil unloading stations, each equipped with 400 gpm transfer pumps. All connections are sealed to prevent vapor release. Next, a recirculating fuel oil pumping system forwards fuel from the storage tanks to the combustion turbine fuel oil delivery blocks for metering and injection into the turbines.

Natural Gas Handling System – Natural gas is supplied from either of two natural gas transmission companies' line taps to separate metering stations that feed a 20 inch diameter pipeline extending approximately 11 miles to the site. In addition, a compressor station at the supply tabs provides additional gas storage within the pipeline to accommodate high demand flowrates. A regulator station located at the site distributes gas to the fuel delivery block for each turbine.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 29
Emission Unit # 29

1) **Type of Unit (Make, Model, Etc.):** Asea Brown Boveria Model 11N2

Date Installed: 6/8/2001 **Cost of Unit:** $45.0 million
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Combustion Turbine #5 (CT5)

2a) **Kind of Unit (Check one):**
1. Indirect Heat Exchanger ____
2. Gas Turbine for Electricity Generation X
3. Pipe Line Compressor Engines:
   ____ Gas Turbine
   ____ Reciprocating engines
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. Industrial Engine ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. Fuel input (mmBTU/hr): 1,368 @ ISO Standard Conditions
2. Power output (hp): ____
   Power output (MW): ____

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

X **C. Natural Gas** _ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	Trace	0.05 gr/100 ft^3	1,020 Btu/scf	1,020 Btu/scf
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units)**:*** N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ **hours/day** __*__ **days/week** __*__ **weeks/year**

* The maximum operating hours for each CT shall not exceed 2,500 hours per year based on a twelve-month rolling total **when combusting fuel oil** (please see **Appendix G)**

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% **Process Heat __________ %** **Power ________ %**

10) Control options for turbine/IC engine (*Check*)

_X_ **(1) Water Injection**
__ **(2) Steam Injection**
__ **(3) Selective Catalytic Reduction (SCR)**
__ **(3) Non-Selective Catalytic Reduction (NSCR)**
__ **(5) Combustion Modification)**
__ **(5) Other (*Specify*) __________**

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

________ **Pulverized Coal Fired:**

__ **Dry Bottom** __ **Wall Fired**
__ **Wet Bottom** __ **Tangentially Fired**

Fly Ash Rejection:

☐ **Yes** ☐ **No**

________ **Cyclone Furnace**

________ **Spreader Stoker**

________ **Overfeed Stoker**

________ **Underfeed Stoker**

________ **Fluidized Bed Combustor:**
______ **Circulating Bed**
______ **Bubbling Bed**

________ **Hand-fed**

________ **Other (*specify*)** ____________________

12) Oil-Fired Unit

______ **Tangentially (Corner) Fired** ______ **Horizontally Opposed (Normal) Fired**

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ **Yes** ☐ **No**

______ **Dutch Oven/Fuel Cell Oven** ______ **Stoker** ______ **Suspension Firing**

______ **Fluidized Bed Combustion (FBC)**

14) Natural Gas-Fired Units

__ **Low NO_x Burners:** ☐ **Yes** ☐ **No**

__ **Flue Gas Recirculation:** ☐ **Yes** ☐ **No**

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

A. **Are sampling ports provided?** ☒ **Yes** ☐ **No**
B. **If yes, are they located in accordance with 40 CFR 60*?** ☒ **Yes** ☐ **No**
C. **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Natural Gas Handling System – Natural gas is supplied from either of two natural gas transmission companies' line taps to separate metering stations that feed a 20 inch diameter pipeline extending approximately 11 miles to the site. In addition, a compressor station at the supply tabs provides additional gas storage within the pipeline to accommodate high demand flowrates. A regulator station located at the site distributes gas to the fuel delivery block for each turbine.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DEP7007A

INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

Emission Point # 39

Emission Unit # 39

1) **Type of Unit (Make, Model, Etc.):** WINCO Generator, Model B35CS-17R1D

Date Installed: Before 1970 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Dix Dam Crest Gate Emergency Generator Engine

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 40
   Power output (MW): 0.03

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** X **G. Gasoline**

____ **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to:[c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	< 30 ppb	N/A	~ 89,000 Btu/gal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day   __*__ days/week   __*__ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat __________ % Power ________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (5) Combustion Modification)
__ (2) Steam Injection
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Other (*Specify*) __________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

________ Pulverized Coal Fired:

__ Dry Bottom   __ Wall Fired
__ Wet Bottom   __ Tangentially Fired

Fly Ash Rejection:

☐ Yes   ☐ No

________ Cyclone Furnace

________ Overfeed Stoker

________ Fluidized Bed Combustor:
______ Circulating Bed
______ Bubbling Bed

_______ Spreader Stoker

_______ Underfeed Stoker

_______ Hand-fed

_______ Other (*specify*) ____________________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired   _______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven   _______ Stoker   _______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) Combustion Air **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☐ **Yes** ☒ **No**
B. If yes, are they located in accordance with 40 CFR 60*? ☐ **Yes** ☐ **No**
C. List other units vented to this stack *None*

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

The Dix Dam Crest Gate Generator has a fuel storage capacity of about 30 gallons. Refueling is done via portable containers as needed.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DEP7007A

INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

Emission Point # 40
Emission Unit # 40

1) **Type of Unit (Make, Model, Etc.):** Caterpillar, Model 3304

Date Installed: Before 2000 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Dix Dam Station Emergency Generator
(Previously noted as Brown Station Emergency Generator engine/Cummins engine. It's a CAT and has been moved to Dix Dam)

2a) **Kind of Unit (Check one):**
1. Indirect Heat Exchanger ____
2. Gas Turbine for Electricity Generation ____
3. Pipe Line Compressor Engines:
   ____ Gas Turbine
   ____ Reciprocating engines
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. Industrial Engine X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. Fuel input (mmBTU/hr): ____
2. Power output (hp): 135
   Power output (MW): 0.10

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

_*_ hours/day _*_ days/week _*_ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ______% Process Heat ______ % Power ______ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ______

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

______ Pulverized Coal Fired:

__ Dry Bottom __ Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

______ Cyclone Furnace
______ Spreader Stoker
______ Overfeed Stoker
______ Underfeed Stoker
______ Fluidized Bed Combustor:
______ Circulating Bed
______ Bubbling Bed
______ Hand-fed
______ Other (*specify*) ____________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired ______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven ______ Stoker ______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

A. **Are sampling ports provided?** ☐ **Yes** ☒ **No**
B. **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**
C. **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Diesel fuel is stored in a 1,000 gal above-ground storage tank that serves the emergency generator. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the generator engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

Emission Point # 41
Emission Unit # 41

1) **Type of Unit (Make, Model, Etc.):** Caterpillar, Model 3306

Date Installed: 2000 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
CT5 Emergency Generator Engine

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   - ____ **Gas Turbine**
   - ____ **Reciprocating engines**
     - **(a) 2-cycle lean burn** ____
     - **(b) 4-cycle lean burn** ____
     - **(c) 4-cycle rich burn** ____
4. **Industrial Engine** X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 308
   Power output (MW): 0.23

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units)*:*** N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day __*__ days/week __*__ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat ___________ % Power _________ %

10) Control options for turbine/IC engine (*Check*)

- **__ (1) Water Injection**
- **__ (3) Selective Catalytic Reduction (SCR)**
- **__ (5) Combustion Modification)**
- **__ (2) Steam Injection**
- **__ (3) Non-Selective Catalytic Reduction (NSCR)**
- **__ (5) Other (*Specify*) ___________**

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

_________ Pulverized Coal Fired:

__ Dry Bottom __ Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection: ☐ **Yes** ☐ **No**

_________ Cyclone Furnace

_________ Overfeed Stoker

_________ Fluidized Bed Combustor:
______ Circulating Bed
______ Bubbling Bed

_______ Spreader Stoker

_______ Underfeed Stoker

_______ Hand-fed

_______ Other (*specify*) _______________________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired _______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ **Yes** ☐ **No**

______ Dutch Oven/Fuel Cell Oven _______ Stoker _______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ **Yes** ☐ **No**

__ Flue Gas Recirculation: ☐ **Yes** ☐ **No**

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

- **A.** **Are sampling ports provided?** ☐ **Yes** ☒ **No**
- **B.** **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**
- **C.** **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Diesel fuel used in the CT5 emergency generator is stored in a 200 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the generator engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 42
Emission Unit # 42

1) **Type of Unit (Make, Model, Etc.):** Perkins Engine, Model DP150P3

Date Installed: 1999 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
CT6 Emergency Generator Engine

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) **2-cycle lean burn** ____
   (b) **4-cycle lean burn** ____
   (c) **4-cycle rich burn** ____
4. **Industrial Engine** X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 230
   Power output (MW): 0.17

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units)****: N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day   __*__ days/week   __*__ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________%   Process Heat __________ %   Power ________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) __________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

________ Pulverized Coal Fired:

__ Dry Bottom   __ Wall Fired
__ Wet Bottom   __ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

________ Cyclone Furnace
________ Spreader Stoker
________ Overfeed Stoker
________ Underfeed Stoker
________ Fluidized Bed Combustor:
  ______ Circulating Bed
  ______ Bubbling Bed
________ Hand-fed
________ Other (*specify*) ____________________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired   ______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven   ______ Stoker   ______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) Combustion Air **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) Additional Stack Data

A. **Are sampling ports provided?** ☐ **Yes** ☒ **No**
B. **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**
C. **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Diesel fuel used in the CT6 emergency generator is stored in a 200 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the generator engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DEP7007A

INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

Emission Point # 43
Emission Unit # 43

1) **Type of Unit (Make, Model, Etc.):** Perkins Engine, Model DP150P3

Date Installed: 1999 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
CT7 Emergency Generator Engine

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 230
   Power output (MW): 0.17

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units)****: N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day   __*__ days/week   __*__ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% Process Heat ____________ % Power __________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ____________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

__________ Pulverized Coal Fired:

__ Dry Bottom   __ Wall Fired
__ Wet Bottom   __ Tangentially Fired

Fly Ash Rejection:

☐ Yes   ☐ No

__________ Cyclone Furnace

________ Spreader Stoker

__________ Overfeed Stoker

________ Underfeed Stoker

__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

________ Hand-fed

________ Other (*specify*) __________________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired   ________ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven   ________ Stoker   ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) Combustion Air **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☐ **Yes** ☒ **No**
B. If yes, are they located in accordance with 40 CFR 60*? ☐ **Yes** ☐ **No**
C. List other units vented to this stack *None*

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Diesel fuel used in the CT7 emergency generator is stored in a 200 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the generator engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

Emission Point # 44
Emission Unit # 44

1) **Type of Unit (Make, Model, Etc.):** Cummins, Model 681A5.9-F1

Date Installed: 1994 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit: CT Area Fire Pump Engine

2a) **Kind of Unit (Check one):**
1. Indirect Heat Exchanger ____
2. Gas Turbine for Electricity Generation ____
3. Pipe Line Compressor Engines:
   ____ Gas Turbine
   ____ Reciprocating engines
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. Industrial Engine X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. Fuel input (mmBTU/hr): ____
2. Power output (hp): 208
   Power output (MW): 0.16

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ A. Coal ____ B. Fuel Oil # (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ C. Natural Gas ____ D. Propane ____ E. Butane ____ F. Wood ____ G. Gasoline

X H. Diesel ____ I. Other (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a] Maximum	Percent Sulfur[b] Maximum	Heat Content Corresponding to:[c, d] Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day __*__ days/week __*__ weeks/year

** The fire pump engine's primary purpose is to provide power to pump water in case of a fire emergency. Once per year, it is also used to fill ice tanks with water via the fire hydrant at the ice plant. The pump is also used to clean out the oil water separators and to wash the fuel unloading area on the main road once per year. Combined hours for maintenance, testing, and periodic use is still expected to be less than 100 hours per year.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat __________ % Power ________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) __________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

________ Pulverized Coal Fired:

_ Dry Bottom _ Wall Fired
_ Wet Bottom _ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

________ Cyclone Furnace
________ Spreader Stoker
________ Overfeed Stoker
________ Underfeed Stoker
________ Fluidized Bed Combustor:
______ Circulating Bed
______ Bubbling Bed
________ Hand-fed
________ Other (*specify*) ____________________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired ______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven ______ Stoker ______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

A. **Are sampling ports provided?** ☐ **Yes** ☒ **No**
B. **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**
C. **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Diesel fuel used in the CT Area Fire Pump Engine is stored in a 300 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 45
Emission Unit # 45

1) **Type of Unit (Make, Model, Etc.):** John Deere, Model 6081HF001, 8.1 L Displacement

Date Installed: Manufactured 4/17/2007, installed 2007, startup in 2/2008 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Steam Plant Emergency Fire Pump Engine #1

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   - ____ **Gas Turbine**
   - ____ **Reciprocating engines**
     - **(a) 2-cycle lean burn** ____
     - **(b) 4-cycle lean burn** ____
     - **(c) 4-cycle rich burn** ____
4. **Industrial Engine** X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 375 (@2,100 rpm)
   Power output (MW): 0.28

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to:[c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units***)*: N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

___*___ hours/day ___*___ days/week ___*___ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat ___________ % Power _________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ___________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

_________ Pulverized Coal Fired:

__ Dry Bottom __ Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

_________ Cyclone Furnace
_______ Spreader Stoker

_________ Overfeed Stoker
_______ Underfeed Stoker

_________ Fluidized Bed Combustor:
______ Circulating Bed
______ Bubbling Bed

_______ Hand-fed

_______ Other (*specify*) ________________________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired
_______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven _______ Stoker _______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

A. **Are sampling ports provided?** ☐ **Yes** ☐ **No** *Ports will be added as necessary.*

B. **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**

C. **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Diesel fuel used in Steam Plant Emergency Fire Pump Engine #1 is stored in a dedicated 440 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

*(Submit copies of this form for each individual unit.
Make additional copies as needed)*

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 46
Emission Unit # 46

1) **Type of Unit (Make, Model, Etc.):** John Deere, Model 6081HF001, 8.1 L Displacement

Date Installed: Manufactured 4/20/2007, installed 2007, startup in 2/2008 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Steam Plant Emergency Fire Pump Engine #2

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 375 (@2,100 rpm)
   Power output (MW): 0.28

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to:[c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate** (***please specify units)*:*** N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

___*___ hours/day ___*___ days/week ___*___ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat __________ % Power _________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (5) Combustion Modification)
__ (2) Steam Injection
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Other (*Specify*) __________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

________ Pulverized Coal Fired:
__ Dry Bottom __ Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

________ Cyclone Furnace
________ Overfeed Stoker
________ Fluidized Bed Combustor:
_____ Circulating Bed
_____ Bubbling Bed

________ Spreader Stoker
________ Underfeed Stoker
________ Hand-fed
________ Other (*specify*) ____________________

12) Oil-Fired Unit

______ Tangentially (Corner) Fired ______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven ______ Stoker ______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

16) **Additional Stack Data**

- **A.** **Are sampling ports provided?** ☐ **Yes** ☐ **No** *Ports will be added as necessary.*
- **B.** **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**
- **C.** **List other units vented to this stack** *None*

17) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

18) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Diesel fuel used in the Steam Plant Emergency Fire Pump Engine #2 is stored in a dedicated 440 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

*(Submit copies of this form for each individual unit.
Make additional copies as needed)*

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 47
Emission Unit # 47

1) **Type of Unit (Make, Model, Etc.):** John Deere, Model 6125HF070, 12.5 L Displacement

Date Installed: Manufactured 4/25/2007, installed 2008, startup expected in 2010 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Emergency Quench Water Pump Engine #1

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   ____ **Reciprocating engines**
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. **Industrial Engine** X

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 485 (@1,760 rpm)
   Power output (MW): 0.36

SECTION 1. FUEL

3) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) **Secondary Fuel** (*if any, specify type*): None

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to:[c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

a. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
b. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
c. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
d. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** N/A

7) **Fuel Source or supplier:** Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

8) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day   __*__ days/week   __*__ weeks/year

** Emergency use only.*

9) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat ___________ % Power _________ %

10) Control options for turbine/IC engine (*Check*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (*Specify*) ___________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

11) Coal-Fired Units

_________ Pulverized Coal Fired:

__ Dry Bottom   __ Wall Fired
__ Wet Bottom   __ Tangentially Fired

Fly Ash Rejection:

☐ Yes ☐ No

_________ Cyclone Furnace
_________ Overfeed Stoker
_________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

_______ Spreader Stoker
_______ Underfeed Stoker
_______ Hand-fed
_______ Other (*specify*) ________________________

12) Oil-Fired Unit

_______ Tangentially (Corner) Fired   _______ Horizontally Opposed (Normal) Fired

13) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven   _______ Stoker   _______ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

14) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) Combustion Air **Draft: ________ Natural ________ Induced**

Forced Pressure __________ lbs/sq. in.

Percent excess air (air supplied in excess of theoretical air) __________ %

SECTION III

16) Additional Stack Data

A. Are sampling ports provided? ☐ **Yes** ☐ **No** *Ports will be added as necessary.*

B. If yes, are they located in accordance with 40 CFR 60*? ☐ **Yes** ☐ **No**

C. List other units vented to this stack *None*

17) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

18) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

Diesel fuel used in the Emergency Quench Water Pump Engine #1 is stored in a dedicated 550 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

*(Submit copies of this form for each individual unit.
Make additional copies as needed)*

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 48
Emission Unit # 48

1) Type of Unit (Make, Model, Etc.): John Deere, Model 6125HF070, 12.5 L Displacement

Date Installed: Manufactured 4/26/2007, installed 2008, startup expected in 2010 **Cost of Unit:** N/A
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Emergency Quench Water Pump Engine #2

2a) Kind of Unit (Check one):
1. Indirect Heat Exchanger ____
2. Gas Turbine for Electricity Generation ____
3. Pipe Line Compressor Engines:
   ____ Gas Turbine
   ____ Reciprocating engines
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn ____
   (c) 4-cycle rich burn ____
4. Industrial Engine X

2b) Rated Capacity: (Refer to manufacturer's specifications)
1. Fuel input (mmBTU/hr): ____
2. Power output (hp): 485 (@1,760 rpm)
   Power output (MW): 0.36

SECTION 1. FUEL

4) Type of Primary Fuel (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

X **H. Diesel** ____ **I. Other** (*specify*) ____

4) Secondary Fuel (*if any, specify type*): None

5) Fuel Composition

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary	N/A	15 ppm or 0.0015%	N/A	~ 138 MMBtu/Mgal
Secondary				

e. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
f. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
g. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
h. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) Maximum Annual Fuel Usage Rate (*please specify units*)*: N/A

8) Fuel Source or supplier: Varies

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

__*__ hours/day __*__ days/week __*__ weeks/year

** Emergency use only.*

16) If this unit is multipurpose, describe percent in each use category:

Space Heat ________% Process Heat __________ % Power ________ %

17) Control options for turbine/IC engine (*Check*)

- __ (1) Water Injection
- __ (2) Steam Injection
- __ (3) Selective Catalytic Reduction (SCR)
- __ (3) Non-Selective Catalytic Reduction (NSCR)
- __ (5) Combustion Modification)
- __ (5) Other (*Specify*) __________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

18) Coal-Fired Units

________ Pulverized Coal Fired:

__ Dry Bottom __ Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

________ Cyclone Furnace

________ Spreader Stoker

________ Overfeed Stoker

________ Underfeed Stoker

________ Fluidized Bed Combustor:
______ Circulating Bed
______ Bubbling Bed

________ Hand-fed

________ Other (*specify*) ____________________

19) Oil-Fired Unit

______ Tangentially (Corner) Fired ______ Horizontally Opposed (Normal) Fired

20) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

______ Dutch Oven/Fuel Cell Oven ______ Stoker ______ Suspension Firing

______ Fluidized Bed Combustion (FBC)

21) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

19) **Additional Stack Data**

A. **Are sampling ports provided?** ☐ **Yes** ☐ **No** *Ports will be added as necessary.*

B. **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**

C. **List other units vented to this stack** *None*

20) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

21) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

Diesel fuel used in the Emergency Quench Water Pump Engine #2 is stored in a dedicated 550 gal above-ground storage tank. Fuel is transported via fuel trucks to the storage tank. Fuel is delivered to the engine from the tank via hard piping. The fuel handling and storage operations are not a source of dust.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

*(Submit copies of this form for each individual unit.
Make additional copies as needed)*

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 49
Emission Unit # 49

1) Type of Unit (Make, Model, Etc.): Generac/Doosan, 390, CI Tier II certified emergency diesel engine

Date Installed: upon approval **Cost of Unit:** $75,000
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 49

2a) Kind of Unit (Check one):
1. **Indirect Heat Exchanger** ______
2. **Gas Turbine for Electricity Generation** ______
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   X **Reciprocating engines** **(Tier II certified emergency diesel engine, CI engine)**
   (a) 2-cycle lean burn ______
   (b) 4-cycle lean burn ______
   (c) 4-cycle rich burn ______
4. **Industrial Engine** ______

2b) Rated Capacity: (Refer to manufacturer's specifications)
1. **Fuel input (mmBTU/hr):**
2. **Power output (hp):** 752
   Power output (MW): ______

SECTION 1. FUEL

4) Type of Primary Fuel (*Check*):

____**A. Coal** ____ **B. Fuel Oil #** **(*Check one*)** **No. 2 ultra low sulfur diesel (ULSD) 15 ppm sulfur**
____**C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**
____ **H. Diesel** ____ **I. Other** (*specify*) ______

4) Secondary Fuel (*if any, specify type*): ______

5) Fuel Composition

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary		15 ppm or 0.0015%	N/A	138 MMBtu/Mgal
Secondary				

e. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
f. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
g. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
h. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) Maximum Annual Fuel Usage Rate (*please specify units)*:* Not Applicable

8) Fuel Source or supplier: Numerous – changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

___ hours/day ________ days/week ________ weeks/year (emergency usage, estimated 150 hr/year with 30 min/week for testing and 1 annual 4-hr annual load test)

16) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% Process Heat ____________ % Power __________ %

17) Control options for turbine/IC engine (C*heck*)

- __ (1) Water Injection
- __ (2) Steam Injection
- __ (3) Selective Catalytic Reduction (SCR)
- __ (3) Non-Selective Catalytic Reduction (NSCR)
- __ (5) Combustion Modification)
- __ (5) Other (S*pecify*) ____________________________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

18) Coal-Fired Units

__ Pulverized Coal Fired:

Fly Ash Rejection: ☐ Yes ☐ No

___ ____ Dry Bottom _ Wall Fired

__ Wet Bottom _ Tangentially Fired

__________ Cyclone Furnace

________ Spreader Stoker

__________ Overfeed Stoker

________ Underfeed Stoker

__________ Fluidized Bed Combustor:

_______ Circulating Bed

_______ Bubbling Bed

________ Hand-fed

________ Other (*specify*) __________________________

19) Oil-Fired Unit

_______ Tangentially (Corner) Fired

________ Horizontally Opposed (Normal) Fired

20) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven ________ Stoker ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

21) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) ______ **%**

SECTION III

19) **Additional Stack Data**

- **A.** **Are sampling ports provided?** ☐ **Yes** ☒ **No**
- **B.** **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**
- **D.** **List other units vented to this stack :** **Units 1& 2**

20) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

21) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 51
Emission Unit # 51

1) **Type of Unit (Make, Model, Etc.):** Cummins, QSK23-G7 NR2, 4 stroke lean burn, Tier II certified Emergency Diesel Engine (Nameplate 1220 HP)

Date Installed: Dec 2014 (startup) **Cost of Unit:** $188,500
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 50 Emergency Diesel Generator

2a) **Kind of Unit (Check one):**
1. **Indirect Heat Exchanger** ____
2. **Gas Turbine for Electricity Generation** ____
3. **Pipe Line Compressor Engines:**
   ____ **Gas Turbine**
   X **Reciprocating engines** **(Tier II certified emergency diesel generator, 4 stroke lean burn, CI engine)**
   - **(a) 2-cycle lean burn** ____
   - **(b) 4-cycle lean burn** X
   - **(c) 4-cycle rich burn** ____
4. **Industrial Engine** ____

2b) **Rated Capacity: (Refer to manufacturer's specifications)**
1. **Fuel input (mmBTU/hr):** ____
2. **Power output (hp):** 1220 (nameplate)
   Power output (MW): ____

SECTION 1. FUEL

5) **Type of Primary Fuel** (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ **1** ____ **2** ____ **3** ____ **4** ____ **5** ____ **6**

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** X **I. Other** (*specify*) Ultra Low Sulfur Diesel (ULSD) 15 ppm sulfur

4) **Secondary Fuel** (*if any, specify type*): ____

5) **Fuel Composition**

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary		15 ppm or 0.0015%	N/A	138 MMBtu/Mgal
Secondary				

i. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
j. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
k. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
l. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) **Maximum Annual Fuel Usage Rate (*please specify units*)*:** ***Emergency generator (cals based on 500 hrs.)***

9) **Fuel Source or supplier:** Numerous - changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

22) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

___ hours/day ________ days/week ________ weeks/year (emergency usage, estimated 120 hr/year max with 30 min/month for testing and 1 annual 4-hr annual load test)

23) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% Process Heat ____________ % Power __________ %

24) Control options for turbine/IC engine (C*heck*)

- __ (1) Water Injection
- __ (2) Steam Injection
- __ (3) Selective Catalytic Reduction (SCR)
- __ (3) Non-Selective Catalytic Reduction (NSCR)
- __ (5) Combustion Modification)
- __ (5) Other (S*pecify*) ___________________________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

25) Coal-Fired Units

__________ Pulverized Coal Fired:

_ Dry Bottom __ Wall Fired
__ Wet Bottom __ Tangentially Fired

Fly Ash Rejection: ☐ Yes ☐ No

__________ Cyclone Furnace

________ Spreader Stoker

__________ Overfeed Stoker

________ Underfeed Stoker

__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

________ Hand-fed

________ Other (*specify*) _________________________

26) Oil-Fired Unit

_______ Tangentially (Corner) Fired

____ Horizontally Opposed (Normal) Fired

27) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven ________ Stoker ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

28) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A
(Continued)

15) Combustion Air Draft: ________ Natural ________ Induced

Forced Pressure __________ lbs/sq. in.

Percent excess air (air supplied in excess of theoretical air) __________ %

SECTION III

22) Additional Stack Data

A. Are sampling ports provided? ☐ Yes ☒ No
B. If yes, are they located in accordance with 40 CFR 60*? ☐ Yes ☐ No
E. List other units vented to this stack ____

23) Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.

24) Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

(Submit copies of this form for each individual unit. Make additional copies as needed)

DEP7007A
INDIRECT HEAT EXCHANGER, TURBINE, INTERNAL COMBUSTION ENGINE

Emission Point # 52
Emission Unit # 52

1) Type of Unit (Make, Model, Etc.): Cummins, QSK23-G7 NR2, 4 stroke lean burn, Tier II certified Emergency Diesel Engine (Nameplate 1220 HP)

Date Installed: Dec 2014 (startup) **Cost of Unit:** $188,500
(Date unit was installed, modified or reconstructed, whichever is later.)

Where more than one unit is present, identify with Company's identification or code for this unit:
Unit 51 Emergency Diesel Generator

2a) Kind of Unit (Check one):
1. Indirect Heat Exchanger ____
2. Gas Turbine for Electricity Generation ____
3. Pipe Line Compressor Engines:
   ____ Gas Turbine
   X Reciprocating engines (Tier II certified emergency diesel generator, 4 stroke lean burn, CI engine)
   (a) 2-cycle lean burn ____
   (b) 4-cycle lean burn X
   (c) 4-cycle rich burn ____
4. Industrial Engine ____

2b) Rated Capacity: (Refer to manufacturer's specifications)
1. Fuel input (mmBTU/hr): ____
2. Power output (hp): 1220 (nameplate)
   Power output (MW): ____

SECTION 1. FUEL

6) Type of Primary Fuel (*Check*):

____ **A. Coal** ____ **B. Fuel Oil #** (*Check one*) ____ 1 ____ 2 ____ 3 ____ 4 ____ 5 ____ 6

____ **C. Natural Gas** ____ **D. Propane** ____ **E. Butane** ____ **F. Wood** ____ **G. Gasoline**

____ **H. Diesel** X **I. Other** (*specify*) Ultra Low Sulfur Diesel (ULSD) 15 ppm sulfur

4) Secondary Fuel (*if any, specify type*): ____

5) Fuel Composition

Type	Percent Ash[a]	Percent Sulfur[b]	Heat Content Corresponding to: [c, d]	
	Maximum	Maximum	Maximum Ash	Maximum Sulfur
Primary		15 ppm or 0.0015%	N/A	138 MMBtu/Mgal
Secondary				

m. As received basis. Proximate Analysis for Ash. (May use values in your fuel contract)
n. As received basis. Ultimate Analysis for Sulfur. (May use values in your fuel contract)
o. Higher Heating Value, BTU/Unit. (May use values in your fuel contract)
p. Suggested units are: Pounds for solid fuel, gallon for liquid fuels, and cu. Ft. for gaseous fuels. If other units are used, please specify.

6) Maximum Annual Fuel Usage Rate (***please specify units)****: ***Emergency generator (cals based on 500 hrs.)***

10) Fuel Source or supplier: Numerous - changes frequently

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

DEP7007A (Continued)

29) MAXIMUM OPERATING SCHEDULE FOR THIS UNIT*

___ hours/day ________ days/week ________ weeks/year (emergency usage, estimated 120 hr/year max with 30 min/month for testing and 1 annual 4-hr annual load test)

30) If this unit is multipurpose, describe percent in each use category:

Space Heat _________% Process Heat ____________ % Power __________ %

31) Control options for turbine/IC engine (C*heck*)

__ (1) Water Injection
__ (2) Steam Injection
__ (3) Selective Catalytic Reduction (SCR)
__ (3) Non-Selective Catalytic Reduction (NSCR)
__ (5) Combustion Modification)
__ (5) Other (S*pecify*) ___________________________

IMPORTANT: Form DEP7007N must also be completed for this unit.

SECTION II COMPLETE ONLY FOR INDIRECT HEAT EXCHANGERS

32) Coal-Fired Units

__________ Pulverized Coal Fired:

_ Dry Bottom **__ Wall Fired**
__ Wet Bottom **__ Tangentially Fired**

Fly Ash Rejection:

☐ Yes ☐ No

__________ Cyclone Furnace

________ Spreader Stoker

__________ Overfeed Stoker

________ Underfeed Stoker

__________ Fluidized Bed Combustor:
_______ Circulating Bed
_______ Bubbling Bed

________ Hand-fed

________ Other (*specify*) _________________________

33) Oil-Fired Unit

_______ Tangentially (Corner) Fired **____ Horizontally Opposed (Normal) Fired**

34) Wood-Fired Unit

Fly-Ash Reinjection: ☐ Yes ☐ No

_______ Dutch Oven/Fuel Cell Oven ________ Stoker ________ Suspension Firing

_______ Fluidized Bed Combustion (FBC)

35) Natural Gas-Fired Units

__ Low NO_x Burners: ☐ Yes ☐ No

__ Flue Gas Recirculation: ☐ Yes ☐ No

*Should be entered only if applicant requests operating restriction through federally enforceable limitations.

**DEP7007A
(Continued)**

15) **Combustion Air** **Draft:** ________ **Natural** ________ **Induced**

Forced Pressure __________ **lbs/sq. in.**

Percent excess air (air supplied in excess of theoretical air) __________ **%**

SECTION III

25) **Additional Stack Data**

- **A.** **Are sampling ports provided?** ☐ **Yes** ☒ **No**
- **B.** **If yes, are they located in accordance with 40 CFR 60*?** ☐ **Yes** ☐ **No**
- **F.** **List other units vented to this stack** ____

26) **Attach manufacturer's specifications and guaranteed performance data for the indirect heat exchanger. Include information concerning fuel input, burners and combustion chamber dimensions.**

27) **Describe fuel transport, storage methods and related dust control measures, including ash disposal and control.**

*Applicant assumes responsibility for proper location of sampling ports if the Division for Air Quality requires a compliance demonstration stack test.

Emission Unit # (1)	Process Description (2)	Continuous or Batch (3)	Maximum Operating Schedule (Hours/Day, Days/Week, Weeks/Year) (4)	Process Equipment (Make, Model, Etc.) (5)	Date Installed (6)
21	Dry Fly Ash Handling	C	24 hr/day, 7 days/week, 52 weeks/yr	Pulse Jet Fabric Filter Dust Collector	1/1982
36	Unit 1 Cooling Tower with Drift Eliminators	C	24 hr/day, 7 days/week, 52 weeks/yr	N/A	5/1957
37	Unit 2 Cooling Tower with Drift Eliminators	C	24 hr/day, 7 days/week, 52 weeks/yr	N/A	6/1963
38	Unit 3 Cooling Tower with Drift Eliminators	C	24 hr/day, 7 days/week, 52 weeks/yr	N/A	7/1971

Emission Unit # (1)	Process Description	List Raw Material(s) Used (7)	Maximum Quantity Input Of Each Raw Material (Specify Units/Hour) (8) See Item 18	Type of Products (9) See Item 18	Quantity Output (Specify Units)	
					Maximum Hourly Rated Capacity (Specify Units) (10a)	Maximum Annual (Specify Units) (10b)
21	Dry Fly Ash Handling	Fly Ash	79.5 tons/hr	Fly Ash	79.5 tons/hr	N/A
36	Unit 1 Cooling Tower with Drift Eliminators	Water	4.08 MMgal/hr	None	4.08 MMgal/hr	N/A
37	Unit 2 Cooling Tower with Drift Eliminators	Water	6.00 MMgal/hr	None	6.00 MMgal/hr	N/A
38	Unit 3 Cooling Tower with Drift Eliminators	Water	10.38 MMgal/hr	None	10.38 MMgal/hr	N/A

Emission Unit # (1)	Process Description	Fuel Type for Process Heat (11)	Rated Burner Capacity (MMBTU/Hour) (12)	Fuel Composition		Fuel Usage Rates		Note:
				% Sulfur (13a)	% Ash (13b)	Maximum Hourly (14a)	Maximum Annual (14b)	If combustion products are emitted along with process emissions, indicate so by writing "combined." (15)
21	Dry Fly Ash Handling	N/A	N/A	N/A	N/A	N/A	N/A	
36	Unit 1 Cooling Tower with Drift Eliminators	N/A	N/A	N/A	N/A	N/A	N/A	
37	Unit 2 Cooling Tower with Drift Eliminators	N/A	N/A	N/A	N/A	N/A	N/A	
38	Unit 3 Cooling Tower with Drift Eliminators	N/A	N/A	N/A	N/A	N/A	N/A	

Imber

Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007L

Concrete, Asphalt, Coal, Aggregate, Feed, Corn, Flour, Grain, & Fertilizer

Coal Handling Processes

1) Type of Operation(s):
_______Concrete _______Asphalt X Coal _______Aggregate Processing
_______Feed, Corn & Flour _______Grain _______Fertilizer

2) Operating Schedule: 24 Hours/day 7 Days/Week 52 Weeks/Year Percent
Annual Throughput: Dec.-Feb. 25 % Mar.-May 25 % June-Aug. 25 %
Sept.-Nov. 25 %

3) Paved Haul Road Length ≈ 1 Miles Unpaved Haul Road Length______Miles
Describe Dust Control Method for Haul Road(s) and Yard Area Wet Suppression

Depending on the type of operation (*as checked in box 1*), complete the appropriate section(s). Also, attach a flow diagram showing all of the emission point numbers, and list the numbers on this form where applicable.

DEP7007L
Continued

SECTION III COAL OPERATIONS ONLY *(EU07, EU09, EU13, EU16)*

14) Specify the Maximum Operating Rate of Each Applicable Facility and the Corresponding Control Equipment:

Emission Point No.	Affected Facility (Specify quantity in blank)	Max. Capacity*		Control Equipment***	Cost of Controls
		(tons/hr.	(tons/yr.)**		
Fugitive	Receiving Hopper(s) *2*	*820*		*Enclosure*	*Unknown**
16	Primary Crusher(s) *1*	*1,640*		*Wet-Type Dust Collector*	*Unknown**
	Secondary Crusher(s) ____				
	Screen(s) _______				
Fugitive	Conveyor Transfer Point(s) *15*	*820*		*Enclosure*	*Unknown**
Fugitive	Stockpile(s) *1*	*1,640*		*Compaction/Wet Suppression*	*N/A*
	Rail Loadout(s) _________				
	Barge Loadout(s) ________				
	Truck Loadout(s) _______				
	Thermal Dryer(s) _______				
	Other (specify) _________				** Cost of controls included in cost of original coal handling system.*

Attach a flow diagram showing all of the emission point numbers, and list the emission point numbers on this form where applicable. This flow diagram should be used to supplement the above information. For example, if there are two conveyor transfer points at 500 tons/hour and three conveyor transfer points at 1000 tons/hour, this distinction can be made on the flow diagram rather than in the table above. If this type of clarification is necessary, please make a note to see the attached flow diagram in the "maximum capacity" column above. *Refer to PFD in Appendix C of application.*

***The maximum capacity should represent the maximum tons/hour that the piece of equipment was designed to physically handle. This number may be larger than you anticipate ever utilizing. For instance, a crusher may be able to handle 1000 tons/hour at its largest setting, but you may plan to operate the crusher at 800 tons/hour. In this case, 1000 tons/hour should still be used in the application. For "shop-made" conveyors or other equipment for which manufacturers' data would not be available, an estimate should be made as to the maximum hourly tonnage that the equipment can physically handle. Again, the maximum number should be used in place of what you may plan to actually use.**
****Should be entered only if applicant requests operating restrictions through federally enforceable permit conditions.**
*****Complete the details on DEP7007N, and submit documents to substantiate control efficiency.**

15) Describe briefly the disposal of particulates collected in the baghouse and/or other waste generated at the site.
Coal dust is collected in the crusher as a slurry and is directed to the coal pile runoff retention basin.

Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007L

Concrete, Asphalt, Coal, Aggregate, Feed, Corn, Flour, Grain, & Fertilizer

Limestone Processing System

2) Type of Operation(s):
_______Concrete _______Asphalt_______Coal ___X___ Aggregate Processing
_______Feed, Corn & Flour _______Grain _______Fertilizer

2) Operating Schedule: ___24___ Hours/day ___7___ Days/Week ___52___ Weeks/Year
Percent Annual Throughput: Dec.-Feb. ___25___ % Mar.-May ___25___ % June-Aug. ___25___ %
Sept.-Nov. ___25___ %

3) Paved Haul Road Length ___≈ 0.5___ Miles Unpaved Haul Road Length______Miles
Describe Dust Control Method for Haul Road(s) and Yard Area ___Wet Suppression___

Depending on the type of operation (*as checked in box 1*), complete the appropriate section(s). Also, attach a flow diagram showing all of the emission point numbers, and list the numbers on this form where applicable.

DEP7007L
Continued

SECTION IV AGGREGATE OPERATIONS ONLY *(EU30, EU31, EU32, EU33, EU34)*

16) Specify the Maximum Operating Rate of Each Applicable Facility and the Corresponding Control Equipment:

Emission Point No.	Affected Facility (specify quantity in blank)	Max. Capacity* (tons/hr.)	Max. Capacity* (tons/yr.)**	Control Equipment ***	Cost of Controls
30 *31*	Receiving Hopper(s) *2*	*250 each*		*Fabric Filters (2)*	
	Primary Crusher(s) ______				
	Secondary Crusher(s) ____				
N/A	Tertiary Crusher(s) *2*	*80 each*		*Located indoors or underground*	*N/A*
N/A	Fines Mill(s) *2*	*80 each*		*Located indoors or underground*	*N/A*
N/A	Screen(s) *2*	*80 each*		*Located indoors or underground*	*N/A*
32 *33* *34*	Conveyor Transfer Points *10*	*500 each*		*Fabric Filters control emissions from Reclaim Conveyors #1 & #2 and the Stacking Tube; Other units conveyor transfer points are located indoors or underground*	
Fugitive	Stockpile(s) *1*	*500*		*None*	*N/A*
	Pug Mill(s) _____				
	Loadout(s) _____				
	Other (specify) _________________				

Attach a flow diagram showing all of the emission point numbers, and list the emission point numbers on this form where applicable. This flow diagram should be used to supplement the above information. For example, if there are two conveyor transfer points at 500 tons/hour and three conveyor transfer points at 1000 tons/hour, this distinction can be made on the flow diagram rather than in the table above. If this type of clarification is necessary, please make a note to see the attached flow diagram in the "maximum capacity" column above. *Refer to PFD in Appendix C of application.*

***The maximum capacity should represent the maximum tons/hour that the piece of equipment was designed to physically handle. This number may be larger than you anticipate ever utilizing.**
****Should be entered only if applicant requests operating restrictions through federally enforceable permit conditions.**
*****Complete the details on DEP7007N, and submit documents to substantiate control efficiency.**

17) Describe briefly the disposal of particulates collected in the baghouse and/or other waste generated at the site.
There is no waste limestone, it is all used in the FGD system.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007N

Emissions, Stacks, and Controls Information

Applicant Name: Brown Station Log #

SECTION I. Emissions Unit and Emission Point Information

KyEIS ID #	Emissions Unit and Emission Point Descriptions	Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
	Emission Unit Name: Date Constructed: HAPs present? ☐ Yes ☐ No					
	Emission Point Name: Source ID: SCC Code: SCC Units: KyEIS Stack #: Fuel Ash Content: Fuel Sulfur Content: Fuel Heat Content Ratio: Applicable Regulations:					
	Emission Point Name: Source ID: SCC Code: SCC Units: KyEIS Stack #: Fuel Ash Content: Fuel Sulfur Content: Fuel Heat Content Ratio: Applicable Regulations:					

Refer to 7007N Form Supplement Table 1.

Imber

DEP7007N
(continued)

SECTION I. Emission Units and Emission Point Information (continued)

KyEIS ID #	Emission Factors			Control Equipment		Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
	Pollutant	Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment Association	Pollutant Overall Efficiency (%)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
				1st control device KyEIS Control ID #: Collection efficiency: 2nd control device KyEIS Control ID #: Collection efficiency:							
				1st control device KyEIS Control ID #: Collection efficiency: 2nd control device KyEIS Control ID #: Collection efficiency:							

Refer to 7007N Form Supplement Table 2.

DEP7007N
(continued)

SECTION II. Stack Information										
KyEIS Stack ID #	Stack Description	Stack Physical Data			Stack Geographic Data			Stack Gas Stream Data		
		Height (ft)	Diameter (ft)	Vent Height (ft)	Vertical Coordinate	Horizontal Coordinate	Coordinate Collection Method Code	Flowrate (acfm)	Temperature (^oF)	Exit Velocity (ft/sec)

Refer to 7007N Form Supplement Table 3.

KyEIS ID#	KyEIS Process ID#	Emission Source Description	Date Construct	HAP present?	KyEIS Stack #	SCC Code	SCC Units	Fuel Ash Content	Fuel Sulfur Content	Fuel Heat Content Ratio	Applicable Regulations	Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
01	1	Unit 1 Indirect Heat Exchanger	5/1/1957	Y	17	10100202	ton	13.8%	3.8%	11,000 Btu/lb	61:015, 52:060, NESHAP UUUUU, CSAPR, MAT, CAM	57.3	8,760	na	na	na
02	1	Unit 2 Indirect Heat Exchanger	6/1/1963	Y	17	10100212	ton	13.8%	3.8%	11,000 Btu/lb	61:015, 52:060, NESHAP UUUUU, CSAPR, MAT, CAM	78.8	8,760	na	na	na
03	1	Unit 3 Indirect Heat Exchanger	7/19/1971	Y	17	10100212	ton	13.8%	3.8%	11,000 Btu/lb	61:015, 52:060, NESHAP UUUUU, CSAPR, MAT, CAM	240.9	8,760	na	na	na
07	1	Coal Handling Operations 07 (West Track Hopper)	1/1/1970	N	Fugitive	30501008	ton	na	na	na	63:010	820	8,760	na	na	na
	2	Coal Handling Operations 07 (Conveyor A-1)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	63:010	820	8,760	na	na	na
	3	Coal Handling Operations 07 (Conveyor E)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	63:010	820	8,760	na	na	na
	4	Coal Handling Operations 07 (Conveyor F)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	63:010	820	8,760	na	na	na
	5	Coal Handling Operations 07 (Conveyor G)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	63:010	820	8,760	na	na	na
	6	Coal Handling Operations 07 (Conveyor H)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	63:010	820	8,760	na	na	na
09	1	Coal Handling Operations 09 (East Track Hopper)	1/1/1993	N	Fugitive	30501008	ton	na	na	na	NSPS Y	820	8,760	na	na	na
	2	Coal Handling Operations 09 (Conveyor A)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	NSPS Y	820	8,760	na	na	na
	3	Coal Handling Operations 09 (Conveyor B)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	NSPS Y	1,640	8,760	na	na	na
	4	Coal Handling Operations 09 (Conveyor C)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	NSPS Y	820	8,760	na	na	na
	5	Coal Handling Operations 09 (Conveyor J)	1/1/1970	N	Fugitive	30501011	ton	na	na	na	NSPS Y	1,640	8,760	na	na	na
	6	Coal Handling Operations 09 (Coal Stockpile)	1/1/1970	N	Fugitive	30501099	ton	na	na	na	NSPS Y	1,640	8,760	na	na	na
13	1	Coal Handling Operations 13 (Conveyor D)	1/1/1956	N	13	30501011	ton	na	na	na	61:020	820	8,760	na	na	na
	2	Coal Handling Operations 13 (Conveyor K-1)	1/1/1970	N	14	30501011	ton	na	na	na	61:020	820	8,760	na	na	na
	3	Coal Handling Operations 13 (Conveyor K)	1/1/1970	N	15	30501011	ton	na	na	na	61:020	820	8,760	na	na	na
16	1	Coal Crushing (Four Crushers and Crusher House)	1/1/1956	N	16	30501010	ton	na	na	na	61:020	1,640	8,760	na	na	na
21	1	Dry Fly Ash Handling	1/1/1982	N	21	30599999	ton	na	na	na	59:010	79.5	8,760	na	na	na
23	1	Combustion Turbine Unit 9 (Fuel: Distillate Oil)	11/28/1995	Y	23	20100101	1000 gal	0.01%	0.05%	138 MMBtu/1000gal	NSPS GG, 51:017, 40 CFR 75	9.91	2,500	na	na	2,500
	2	Combustion Turbine Unit 9 (Fuel: Natural Gas)	11/28/1995	Y	23	20100201	MMcf	Neg	Neg	1020 Btu/scf		1.34	8,760	na	na	2,500
24	1	Combustion Turbine Unit 10 (Fuel: Distillate Oil)	12/22/1995	Y	24	20100101	1000 gal	0.01%	0.05%	138 MMBtu/1000gal	NSPS GG, 51:017, 40 CFR 75	9.91	2,500	na	na	2,500
	2	Combustion Turbine Unit 10 (Fuel: Natural Gas)	12/22/1995	Y	24	20100201	MMcf	Neg	Neg	1020 Btu/scf		1.34	8,760	na	na	2,500
25	1	Combustion Turbine Unit 8 (Fuel: Distillate Oil)	3/1/1996	Y	25	20100101	1000 gal	0.01%	0.05%	138 MMBtu/1000gal	NSPS GG, 51:017, 40 CFR 75	9.91	2,500	na	na	2,500
	2	Combustion Turbine Unit 8 (Fuel: Natural Gas)	3/1/1996	Y	25	20100201	MMcf	Neg	Neg	1020 Btu/scf		1.34	8,760	na	na	2,500
26	1	Combustion Turbine Unit 11 (Fuel: Distillate Oil)	5/8/1996	Y	26	20100101	1000 gal	0.01%	0.05%	138 MMBtu/1000gal	NSPS GG, 51:017, 40 CFR 75	9.91	2,500	na	na	2,500
	2	Combustion Turbine Unit 11 (Fuel: Natural Gas)	5/8/1996	Y	26	20100201	MMcf	Neg	Neg	1020 Btu/scf		1.34	8,760	na	na	2,500
27	1	Combustion Turbine Unit 6 (Fuel: Distillate Oil)	8/11/1999	Y	27	20100101	1000 gal	0.01%	0.23%	138 MMBtu/1000gal	NSPS GG, 51:017, 40 CFR 75	12.16	2,500	na	na	2,500
	2	Combustion Turbine Unit 6 (Fuel: Natural Gas)	8/11/1999	Y	27	20100201	MMcf	Neg	Neg	1020 Btu/scf		1.65	8,760	na	na	2,500
28	1	Combustion Turbine Unit 7 (Fuel: Distillate Oil)	8/8/1999	Y	28	20100101	1000 gal	0.01%	0.23%	138 MMBtu/1000gal	NSPS GG, 51:017, 40	12.16	2,500	na	na	2,500

KyEIS ID#	KyEIS Process ID#	Emission Source Description	Date Construct	HAP present?	KyEIS Stack #	SCC Code	SCC Units	Fuel Ash Content	Fuel Sulfur Content	Fuel Heat Content Ratio	Applicable Regulations	Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
	2	Combustion Turbine Unit 7 (Fuel: Natural Gas)	8/8/1999	Y	28	20100201	MMcf	Neg	Neg	1020 Btu/scf	CFR 75	1.65	8,760	na	na	2,500
29	1	Combustion Turbine Unit 5 (Fuel: Natural Gas)	5/8/1996	Y	29	20100201	MMcf	Neg	Neg	1020 Btu/scf	NSPS GG, 51:017, 40 CFR 75	1.34	8,760	na	na	2,500

KyEIS ID#	KyEIS Process ID#	Emission Source Description	Date Construct	HAP present?	KyEIS Stack #	SCC Code	SCC Units	Fuel Ash Content	Fuel Sulfur Content	Fuel Heat Content Ratio	Applicable Regulations	Maximum Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Maximum Operating Parameters: Annual Operating Hours (hrs/yr)	Permitted Operating Parameters: Hourly Operating Rate (SCC Units/hr)	Permitted Operating Parameters: Annual Operating Rate (SCC Units/yr)	Permitted Operating Parameters: Annual Operating Hours (hrs/yr)
30	1	Limestone Truck Dump Station #1	1/1/2008	N	30	30510405	ton	na	na	na	59:010	250	8,760	na	na	na
31	1	Limestone Truck Dump Station #2	1/1/2008	N	31	30510405	ton	na	na	na	59:010	250	8,760	na	na	na
32	1	Limestone Stacking Tube	3/1/2008	N	32	30510305	ton	na	na	na	NSPS OOO	500	8,760	na	na	na
33	1	Limestone Reclaim Conveyor #1	3/1/2008	N	33	30510105	ton	na	na	na	NSPS OOO	500	8,760	na	na	na
34	1	Limestone Reclaim Conveyor #2	3/1/2008	N	34	30510105	ton	na	na	na	NSPS OOO	500	8,760	na	na	na
35	1	Road Fugitives from Truck Traffic on Unpaved and Paved Roads	5/1/1957	N	Fugitive	30501024	VMT	na	na	na	63:010	4.07	8,760	na	na	na
36	1	Unit 1 Cooling Tower with Drift Eliminators	5/1/1957	N	36	38500101	MMgal	na	na	na	na	4.08	8,760	na	na	na
37	1	Unit 2 Cooling Tower with Drift Eliminators	6/1/1963	N	37	38500101	MMgal	na	na	na	na	6.00	8,760	na	na	na
38	1	Unit 3 Cooling Tower with Drift Eliminators	7/19/1971	N	38	38500101	MMgal	na	na	na	na	10.38	8,760	na	na	na
39	1	Dix Dam Crest Gate Emergency Generator	< 1970	Y	39	20201702	1000 gal	na	0.03 ppm	89 MMBtu/1000gal	NESHAP ZZZZ	0.00315	100	na	na	na
40	1	Dix Dam Station Emergency Generator	< 2000	Y	40	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NESHAP ZZZZ	0.00685	100	na	na	na
41	1	CT5 Emergency Generator	2000	Y	41	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NESHAP ZZZZ	0.01562	100	na	na	na
42	1	CT6 Emergency Generator	1999	Y	42	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NESHAP ZZZZ	0.01167	100	na	na	na
43	1	CT7 Emergency Generator	1999	Y	43	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NESHAP ZZZZ	0.01167	100	na	na	na
44	1	CT Area Emergency Fire Pump Engine	1994	Y	44	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NESHAP ZZZZ	0.01055	100	na	na	na
45	1	Emergency Steam Plant Fire Pump Engine #1	4/2007	Y	45	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NSPS IIII; NESHAP ZZZZ	0.01902	100	na	na	na
46	1	Emergency Steam Plant Fire Pump Engine #2	4/2007	Y	46	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NSPS IIII; NESHAP ZZZZ	0.01902	100	na	na	na
47	1	Emergency Quench Water Pump Engine #1	4/2007	Y	47	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NSPS IIII; NESHAP ZZZZ	0.02460	100	na	na	na
48	1	Emergency Quench Water Pump Engine #2	4/2007	Y	48	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NSPS IIII; NESHAP ZZZZ	0.02460	100	na	na	na
49	1	Emergency Tier II 752 HP Diesel RICE	2009	Y	49	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NSPS IIII; NESHAP ZZZZ	0.03814	100	na	na	na
50	6	New Ash/Gypsum Landfill and Haul Trucks	Under Construct	N	50	30502504	VMT	na	na	na	63:010	4.12	8,760	na	na	na
51	1	Emergency Tier II 1220 HP Diesel RICE	2014	Y	51	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NSPS IIII; NESHAP ZZZZ	0.02460	100	na	na	na
52	1	Emergency Tier II 1220 HP Diesel RICE	2014	Y	52	20200102	1000 gal	na	0.0015%	138 MMBtu/1000gal	NSPS IIII; NESHAP ZZZZ	0.02460	100	na	na	na

KyEIS ID #	Process ID(s)	Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
01	1	Unit 1 Indirect Heat Exchanger														
		CO	00630-08-0	0.500	lb/ton	AP42 1.1-3, 9/98	na	na	na	57.3	28.6	na	na	125.4	na	na
		NOX	10102-44-0	22.000	lb/ton	AP42 1.1-3, 9/98	C01A	LNB	50.0%	57.3	1,260.0	630.0	na	5,518.8	2,759.4	na
		PM	na	138.000	lb/ton	AP42 1.1-4, 9/98	C01B	ESP	98.5%	57.3	7,903.6	118.6	320	34,617.9	519.3	na
		PM10	na	31.740	lb/ton	AP42 1.1-4, 9/98	C01B	ESP	98.5%	57.3	1,817.8	27.3	na	7,962.1	119.4	na
		PM2.5	na	8.280	lb/ton	AP42 1.1-6, 9/98	C01B	ESP	97.4%	57.3	474.2	12.1	na	2,077.1	53.1	na
		SO2	07446-09-5	144.400	lb/ton	AP42 1.1-3, 9/98	C03D	FGD	98.6%	57.3	8,270.2	115.8	6,489	36,223.4	507.1	na
		VOC (TNMOC)	na	0.060	lb/ton	AP42 1.1-19, 9/98	na	na	na	57.3	3.4	na	na	15.1	na	na
		H2SO4	07664-93-9	2.092	lb/ton	1% conversion to SO3	C03D	FGD	55.0%	57.3	119.8	53.9	na	524.8	236.2	na
		CO_2E	#N/A	4560.655	lb/ton	40 CFR 98 Subpart C	na	na	na	57.3	261,201.2	na	na	1,144,061.1	na	na
		Antimony	07440-36-0	2.24E-04	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	92.9%	57.3	1.28E-02	9.11E-04	na	5.62E-02	3.99E-03	na
		Arsenic	07740-38-2	1.24E-02	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	97.2%	57.3	7.09E-01	2.00E-02	na	3.11E+00	8.75E-02	na
		Beryllium	07440-41-7	2.50E-03	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	99.0%	57.3	1.43E-01	1.41E-03	na	6.28E-01	6.19E-03	na
		Cadmium	07440-43-9	4.89E-04	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	87.8%	57.3	2.80E-02	3.43E-03	na	1.23E-01	1.50E-02	na
		Chromium	07440-47-3	4.22E-03	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	91.2%	57.3	2.42E-01	2.12E-02	na	1.06E+00	9.27E-02	na
		Cobalt	07440-48-4	2.05E-03	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	94.5%	57.3	1.17E-01	6.47E-03	na	5.14E-01	2.83E-02	na
		Lead	07439-92-1	1.00E-02	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	96.5%	57.3	5.73E-01	1.99E-02	na	2.51E+00	8.71E-02	na
		Manganese	07439-96-5	6.32E-03	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	92.0%	57.3	3.62E-01	2.91E-02	na	1.59E+00	1.28E-01	na
		Nickel	07440-02-0	2.22E-03	lb/ton	AP42 1.1-16, 9/98	C01B	ESP	86.7%	57.3	1.27E-01	1.69E-02	na	5.56E-01	7.41E-02	na
		Mercury	07439-97-6	2.40E-04	lb/ton	AP42 1.1-18, 9/98	C01B	ESP	65.4%	57.3	1.37E-02	4.75E-03	na	6.02E-02	2.08E-02	na
		Selenium	07782-49-2	4.00E-03	lb/ton	AP42 1.1-18, 9/98	C01B	ESP	67.5%	57.3	2.29E-01	7.45E-02	na	1.00E+00	3.26E-01	na
		Biphenyl	00092-52-4	1.70E-06	lb/ton	AP42 1.1-13, 9/98	na	na	na	57.3	9.74E-05	na	na	4.26E-04	na	na
		Naphthalene	00091-20-3	1.30E-05	lb/ton	AP42 1.1-13, 9/98	na	na	na	57.3	7.45E-04	na	na	3.26E-03	na	na
		Acetaldehyde	00075-07-0	7.04E-05	lb/ton	PISCES	na	na	na	57.3	4.03E-03	na	na	1.77E-02	na	na
		Acetophenone	00098-86-2	2.64E-05	lb/ton	PISCES	na	na	na	57.3	1.51E-03	na	na	6.62E-03	na	na
		Acrolein	00107-02-8	4.18E-05	lb/ton	PISCES	na	na	na	57.3	2.39E-03	na	na	1.05E-02	na	na
		Benzene	00071-43-2	8.58E-05	lb/ton	PISCES	na	na	na	57.3	4.91E-03	na	na	2.15E-02	na	na
		Benzyl chloride	00100-44-7	6.16E-06	lb/ton	PISCES	na	na	na	57.3	3.53E-04	na	na	1.55E-03	na	na
		Bis(2-ethylhexyl)phthalate	00117-81-7	7.92E-05	lb/ton	PISCES	na	na	na	57.3	4.54E-03	na	na	1.99E-02	na	na
		Bromoform	00075-25-2	3.90E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	2.23E-03	na	na	9.78E-03	na	na
		Carbon disulfide	00075-15-0	2.42E-05	lb/ton	PISCES	na	na	na	57.3	1.39E-03	na	na	6.07E-03	na	na
		2-Chloroacetophenone	00532-27-4	7.00E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	4.01E-04	na	na	1.76E-03	na	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		Chlorobenzene	00108-90-7	3.52E-06	lb/ton	PISCES	na	na	na	57.3	2.02E-04	na	na	8.83E-04	na	na
		Chloroform	00067-66-3	1.76E-05	lb/ton	PISCES	na	na	na	57.3	1.01E-03	na	na	4.42E-03	na	na
		Cumene	00098-82-8	5.30E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	3.04E-04	na	na	1.33E-03	na	na
		Cyanide	00057-12-5	2.50E-03	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	1.43E-01	na	na	6.27E-01	na	na
		Dimethyl sulfate	00077-78-1	4.80E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	2.75E-03	na	na	1.20E-02	na	na
		2,4-Dinitrotoluene	00121-14-2	4.40E-06	lb/ton	PISCES	na	na	na	57.3	2.52E-04	na	na	1.10E-03	na	na
		Ethylbenzene	00100-41-4	1.76E-05	lb/ton	PISCES	na	na	na	57.3	1.01E-03	na	na	4.42E-03	na	na
		Ethyl chloride	00075-00-3	4.20E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	2.41E-03	na	na	1.05E-02	na	na
		Ethylene dibromide	00106-93-4	1.20E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	6.87E-05	na	na	3.01E-04	na	na
		Ethylene dichloride	00107-06-2	4.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	2.29E-03	na	na	1.00E-02	na	na
		Formaldehyde	00050-00-0	5.72E-05	lb/ton	PISCES	na	na	na	57.3	3.28E-03	na	na	1.43E-02	na	na
		Hexane	00110-54-3	6.70E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	3.84E-03	na	na	1.68E-02	na	na
		Isophorone	00078-59-1	2.64E-05	lb/ton	PISCES	na	na	na	57.3	1.51E-03	na	na	6.62E-03	na	na
		Methyl bromide	00074-83-9	1.60E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	9.16E-03	na	na	4.01E-02	na	na
		Methyl chloride	00074-87-3	5.30E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	3.04E-02	na	na	1.33E-01	na	na
		Methyl ethyl ketone	00078-93-3	3.90E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	2.23E-02	na	na	9.78E-02	na	na
		Methyl hydrazine	00060-34-4	1.70E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	9.74E-03	na	na	4.26E-02	na	na
		Methyl methacrylate	00080-62-6	2.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	1.15E-03	na	na	5.02E-03	na	na
		Methyl tert butyl ether	01634-04-4	3.50E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	2.00E-03	na	na	8.78E-03	na	na
		Methylene chloride	00075-09-2	7.92E-05	lb/ton	PISCES	na	na	na	57.3	4.54E-03	na	na	1.99E-02	na	na
		Phenol	00108-95-2	7.26E-05	lb/ton	PISCES	na	na	na	57.3	4.16E-03	na	na	1.82E-02	na	na
		Propionaldehyde	00123-38-6	4.18E-05	lb/ton	PISCES	na	na	na	57.3	2.39E-03	na	na	1.05E-02	na	na
		Styrene	00100-42-5	1.54E-05	lb/ton	PISCES	na	na	na	57.3	8.82E-04	na	na	3.86E-03	na	na
		Tetrachloroethylene	00127-18-4	9.24E-06	lb/ton	PISCES	na	na	na	57.3	5.29E-04	na	na	2.32E-03	na	na
		Toluene	00108-88-3	3.74E-05	lb/ton	PISCES	na	na	na	57.3	2.14E-03	na	na	9.38E-03	na	na
		1,1,1-Trichloroethane	00079-00-5	2.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	57.3	1.15E-03	na	na	5.02E-03	na	na
		Vinyl acetate	00108-05-4	6.82E-06	lb/ton	PISCES	na	na	na	57.3	3.91E-04	na	na	1.71E-03	na	na
		m/p-Xylene	00108-38-3	1.80E-05	lb/ton	PISCES	na	na	na	57.3	1.03E-03	na	na	4.53E-03	na	na
		o-Xylene	00095-47-6	9.68E-06	lb/ton	PISCES	na	na	na	57.3	5.54E-04	na	na	2.43E-03	na	na
		POM	na	4.58E-05	lb/ton	AP42 1.1-17, 9/98	na	na	na	57.3	2.62E-03	na	na	1.15E-02	na	na
		Hydrogen Chloride	07647-01-0	1.44E+00	lb/ton	PISCES	C03D	FGD	80.8%	57.3	82.5	15.8	na	361.2	69.2	na
		Hydrogen Fluoride	07664-39-3	1.68E-01	lb/ton	PISCES	C03D	FGD	86.9%	57.3	9.6	1.3	na	42.3	5.5	na

KyEIS ID #	Process ID(s)	Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
02	1	Unit 2 Indirect Heat Exchanger														
		CO	00630-08-0	0.500	lb/ton	AP42 1.1-3, 9/98	na	na	na	78.8	39.4	na	na	172.5	na	na
		NOX	10102-44-0	15.000	lb/ton	AP42 1.1-3, 9/98	C02A	LNB	35.0%	78.8	1,181.6	768.0	na	5,175.4	3,364.0	na
		PM	na	138.000	lb/ton	AP42 1.1-4, 9/98	C02B	ESP	99.0%	78.8	10,870.6	108.7	281	47,613.4	476.1	na
		PM10	na	31.740	lb/ton	AP42 1.1-4, 9/98	C02B	ESP	99.0%	78.8	2,500.2	25.0	na	10,951.1	109.5	na
		PM2.5	na	8.280	lb/ton	AP42 1.1-6, 9/98	C02B	ESP	98.3%	78.8	652.2	11.1	na	2,856.8	48.7	na
		SO2	07446-09-5	144.400	lb/ton	AP42 1.1-3, 9/98	C03D	FGD	94.9%	78.8	11,374.8	580.1	8,925	49,821.5	2,540.9	na
		VOC (TNMOC)	na	0.060	lb/ton	AP42 1.1-19, 9/98	na	na	na	78.8	4.7	na	na	20.7	na	na
		H2SO4	07664-93-9	2.092	lb/ton	1% conversion to SO3	C03D	FGD	55.0%	78.8	164.8	74.2	na	721.9	324.8	na
		CO_2E	#N/A	4560.655		40 CFR 98 Subpart C	C03D	na	na	#N/A	359,255.2	na	na	1,573,538.0	na	na
		Antimony	07440-36-0	2.24E-04	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	94.5%	78.8	1.77E-02	9.70E-04	na	7.73E-02	4.25E-03	na
		Arsenic	07740-38-2	1.24E-02	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	98.0%	78.8	9.75E-01	1.95E-02	na	4.27E+00	8.52E-02	na
		Beryllium	07440-41-7	2.50E-03	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	99.4%	78.8	1.97E-01	1.25E-03	na	8.64E-01	5.45E-03	na
		Cadmium	07440-43-9	4.89E-04	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	90.0%	78.8	3.86E-02	3.86E-03	na	1.69E-01	1.69E-02	na
		Chromium	07440-47-3	4.22E-03	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	93.1%	78.8	3.33E-01	2.30E-02	na	1.46E+00	1.01E-01	na
		Cobalt	07440-48-4	2.05E-03	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	95.8%	78.8	1.61E-01	6.73E-03	na	7.07E-01	2.95E-02	na
		Lead	07439-92-1	1.00E-02	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	97.5%	78.8	7.88E-01	1.98E-02	na	3.45E+00	8.67E-02	na
		Manganese	07439-96-5	6.32E-03	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	93.7%	78.8	4.98E-01	3.14E-02	na	2.18E+00	1.38E-01	na
		Nickel	07440-02-0	2.22E-03	lb/ton	AP42 1.1-16, 9/98	C02B	ESP	89.0%	78.8	1.75E-01	1.92E-02	na	7.65E-01	8.39E-02	na
		Mercury	07439-97-6	2.40E-04	lb/ton	AP42 1.1-18, 9/98	C02B	ESP	65.4%	78.8	1.89E-02	6.54E-03	na	8.28E-02	2.86E-02	na
		Selenium	07782-49-2	4.00E-03	lb/ton	AP42 1.1-18, 9/98	C02B	ESP	67.5%	78.8	3.15E-01	1.02E-01	na	1.38E+00	4.49E-01	na
		Biphenyl	00092-52-4	1.70E-06	lb/ton	AP42 1.1-13, 9/98	na	na	na	78.8	1.34E-04	na	na	5.87E-04	na	na
		Naphthalene	00091-20-3	1.30E-05	lb/ton	AP42 1.1-13, 9/98	na	na	na	78.8	1.02E-03	na	na	4.49E-03	na	na
		Acetaldehyde	00075-07-0	7.04E-05	lb/ton	PISCES	na	na	na	78.8	5.55E-03	na	na	2.43E-02	na	na
		Acetophenone	00098-86-2	2.64E-05	lb/ton	PISCES	na	na	na	78.8	2.08E-03	na	na	9.11E-03	na	na
		Acrolein	00107-02-8	4.18E-05	lb/ton	PISCES	na	na	na	78.8	3.29E-03	na	na	1.44E-02	na	na
		Benzene	00071-43-2	8.58E-05	lb/ton	PISCES	na	na	na	78.8	6.76E-03	na	na	2.96E-02	na	na
		Benzyl chloride	00100-44-7	6.16E-06	lb/ton	PISCES	na	na	na	78.8	4.85E-04	na	na	2.13E-03	na	na
		Bis(2-ethylhexyl)phthalate	00117-81-7	7.92E-05	lb/ton	PISCES	na	na	na	78.8	6.24E-03	na	na	2.73E-02	na	na
		Bromoform	00075-25-2	3.90E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	3.07E-03	na	na	1.35E-02	na	na
		Carbon disulfide	00075-15-0	2.42E-05	lb/ton	PISCES	na	na	na	78.8	1.91E-03	na	na	8.35E-03	na	na
		2-Chloroacetophenone	00532-27-4	7.00E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	5.51E-04	na	na	2.42E-03	na	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		Chlorobenzene	00108-90-7	3.52E-06	lb/ton	PISCES	na	na	na	78.8	2.77E-04	na	na	1.21E-03	na	na
		Chloroform	00067-66-3	1.76E-05	lb/ton	PISCES	na	na	na	78.8	1.39E-03	na	na	6.07E-03	na	na
		Cumene	00098-82-8	5.30E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	4.17E-04	na	na	1.83E-03	na	na
		Cyanide	00057-12-5	2.50E-03	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	1.97E-01	na	na	8.63E-01	na	na
		Dimethyl sulfate	00077-78-1	4.80E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	3.78E-03	na	na	1.66E-02	na	na
		2,4-Dinitrotoluene	00121-14-2	4.40E-06	lb/ton	PISCES	na	na	na	78.8	3.47E-04	na	na	1.52E-03	na	na
		Ethylbenzene	00100-41-4	1.76E-05	lb/ton	PISCES	na	na	na	78.8	1.39E-03	na	na	6.07E-03	na	na
		Ethyl chloride	00075-00-3	4.20E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	3.31E-03	na	na	1.45E-02	na	na
		Ethylene dibromide	00106-93-4	1.20E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	9.45E-05	na	na	4.14E-04	na	na
		Ethylene dichloride	00107-06-2	4.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	3.15E-03	na	na	1.38E-02	na	na
		Formaldehyde	00050-00-0	5.72E-05	lb/ton	PISCES	na	na	na	78.8	4.51E-03	na	na	1.97E-02	na	na
		Hexane	00110-54-3	6.70E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	5.28E-03	na	na	2.31E-02	na	na
		Isophorone	00078-59-1	2.64E-05	lb/ton	PISCES	na	na	na	78.8	2.08E-03	na	na	9.11E-03	na	na
		Methyl bromide	00074-83-9	1.60E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	1.26E-02	na	na	5.52E-02	na	na
		Methyl chloride	00074-87-3	5.30E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	4.17E-02	na	na	1.83E-01	na	na
		Methyl ethyl ketone	00078-93-3	3.90E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	3.07E-02	na	na	1.35E-01	na	na
		Methyl hydrazine	00060-34-4	1.70E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	1.34E-02	na	na	5.87E-02	na	na
		Methyl methacrylate	00080-62-6	2.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	1.58E-03	na	na	6.90E-03	na	na
		Methyl tert butyl ether	01634-04-4	3.50E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	2.76E-03	na	na	1.21E-02	na	na
		Methylene chloride	00075-09-2	7.92E-05	lb/ton	PISCES	na	na	na	78.8	6.24E-03	na	na	2.73E-02	na	na
		Phenol	00108-95-2	7.26E-05	lb/ton	PISCES	na	na	na	78.8	5.72E-03	na	na	2.50E-02	na	na
		Propionaldehyde	00123-38-6	4.18E-05	lb/ton	PISCES	na	na	na	78.8	3.29E-03	na	na	1.44E-02	na	na
		Styrene	00100-42-5	1.54E-05	lb/ton	PISCES	na	na	na	78.8	1.21E-03	na	na	5.31E-03	na	na
		Tetrachloroethylene	00127-18-4	9.24E-06	lb/ton	PISCES	na	na	na	78.8	7.28E-04	na	na	3.19E-03	na	na
		Toluene	00108-88-3	3.74E-05	lb/ton	PISCES	na	na	na	78.8	2.95E-03	na	na	1.29E-02	na	na
		1,1,1-Trichloroethane	00079-00-5	2.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	78.8	1.58E-03	na	na	6.90E-03	na	na
		Vinyl acetate	00108-05-4	6.82E-06	lb/ton	PISCES	na	na	na	78.8	5.37E-04	na	na	2.35E-03	na	na
		m/p-Xylene	00108-38-3	1.80E-05	lb/ton	PISCES	na	na	na	78.8	1.42E-03	na	na	6.22E-03	na	na
		o-Xylene	00095-47-6	9.68E-06	lb/ton	PISCES	na	na	na	78.8	7.63E-04	na	na	3.34E-03	na	na
		POM	na	5.28E-05	lb/ton	AP42 1.1-17, 9/98	na	na	na	78.8	4.16E-03	na	na	1.82E-02	na	na
		Hydrogen Chloride	07647-01-0	1.44E+00	lb/ton	PISCES	C03D	FGD	80.8%	78.8	113.4	21.7	na	496.8	95.1	na
		Hydrogen Fluoride	07664-39-3	1.68E-01	lb/ton	PISCES	C03D	FGD	86.9%	78.8	13.3	1.7	na	58.1	7.6	na

KyEIS ID #	Process ID(s)	Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
03	1	Unit 3 Indirect Heat Exchanger														
		CO	00630-08-0	0.500	lb/ton	AP42 1.1-3, 9/98	na	na	na	240.9	120.5	na	na	527.6	na	na
		NOX	10102-44-0	15.000	lb/ton	AP42 1.1-3, 9/98	C03A, C03B	LNB, SCR	92.5%	240.9	3,613.6	271.0	371	15,827.7	1,187.1	na
		PM	na	138.000	lb/ton	AP42 1.1-4, 9/98	C03E	PJFF	99.5%	240.9	33,245.5	159.0	159	145,615.1	696.4	na
		PM10	na	31.740	lb/ton	AP42 1.1-4, 9/98	C03E	PJFF	97.9%	240.9	7,646.5	159.0	na	33,491.5	696.4	na
		PM2.5	na	8.280	lb/ton	AP42 1.1-6, 9/98	C03E	PJFF	96.5%	240.9	1,994.7	70.7	na	8,736.9	309.5	na
		SO2	07446-09-5	144.400	lb/ton	AP42 1.1-3, 9/98	C03D	FGD	98.4%	240.9	34,787.3	556.6	1,044	152,368.3	2,437.9	na
		VOC (TNMOC)	na	0.060	lb/ton	AP42 1.1-19, 9/98	na	na	na	240.9	14.5	na	na	63.3	na	na
		H2SO4	07664-93-9	6.625	lb/ton	3% conversion to SO3	C03D	PJFF, DSI, FGD	93.2%	240.9	1,596.1	109.2	na	6,990.8	478.2	na
		CO_2E	#N/A	4560.655	#N/A	40 CFR 98 Subpart C	C03D	na	na	#N/A	1,098,703.3	na	na	4,812,320.4	na	na
		Antimony	07440-36-0	2.24E-04	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	96.5%	240.9	5.40E-02	1.86E-03	na	2.36E-01	8.17E-03	na
		Arsenic	07740-38-2	1.24E-02	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	98.9%	240.9	2.98E+00	3.18E-02	na	1.31E+01	1.39E-01	na
		Beryllium	07440-41-7	2.50E-03	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	99.7%	240.9	6.03E-01	1.69E-03	na	2.64E+00	7.41E-03	na
		Cadmium	07440-43-9	4.89E-04	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	93.1%	240.9	1.18E-01	8.15E-03	na	5.16E-01	3.57E-02	na
		Chromium	07440-47-3	4.22E-03	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	95.5%	240.9	1.02E+00	4.59E-02	na	4.46E+00	2.01E-01	na
		Cobalt	07440-48-4	2.05E-03	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	97.5%	240.9	4.94E-01	1.24E-02	na	2.16E+00	5.42E-02	na
		Lead	07439-92-1	1.00E-02	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	98.6%	240.9	2.41E+00	3.35E-02	na	1.06E+01	1.47E-01	na
		Manganese	07439-96-5	6.32E-03	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	95.9%	240.9	1.52E+00	6.17E-02	na	6.67E+00	2.70E-01	na
		Nickel	07440-02-0	2.22E-03	lb/ton	AP42 1.1-16, 9/98	C03E	PJFF	92.3%	240.9	5.34E-01	4.11E-02	na	2.34E+00	1.80E-01	na
		Mercury	07439-97-6	2.40E-04	lb/ton	AP42 1.1-18, 9/98 adjusted	C03E	PJFF	89.0%	240.9	5.78E-02	6.36E-03	na	2.53E-01	2.79E-02	na
		Selenium	07782-49-2	4.00E-03	lb/ton	AP42 1.1-18, 9/98	C03E	PJFF	67.5%	240.9	9.64E-01	3.13E-01	na	4.22E+00	1.37E+00	na
		Biphenyl	00092-52-4	1.70E-06	lb/ton	AP42 1.1-13, 9/98	na	na	na	240.9	4.10E-04	na	na	1.79E-03	na	na
		Naphthalene	00091-20-3	1.30E-05	lb/ton	AP42 1.1-13, 9/98	na	na	na	240.9	3.13E-03	na	na	1.37E-02	na	na
		Acetaldehyde	00075-07-0	7.04E-05	lb/ton	PISCES	na	na	na	240.9	1.70E-02	na	na	7.43E-02	na	na
		Acetophenone	00098-86-2	2.64E-05	lb/ton	PISCES	na	na	na	240.9	6.36E-03	na	na	2.79E-02	na	na
		Acrolein	00107-02-8	4.18E-05	lb/ton	PISCES	na	na	na	240.9	1.01E-02	na	na	4.41E-02	na	na
		Benzene	00071-43-2	8.58E-05	lb/ton	PISCES	na	na	na	240.9	2.07E-02	na	na	9.05E-02	na	na
		Benzyl chloride	00100-44-7	6.16E-06	lb/ton	PISCES	na	na	na	240.9	1.48E-03	na	na	6.50E-03	na	na
		Bis(2-ethylhexyl)phthalate	00117-81-7	7.92E-05	lb/ton	PISCES	na	na	na	240.9	1.91E-02	na	na	8.36E-02	na	na
		Bromoform	00075-25-2	3.90E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	9.40E-03	na	na	4.12E-02	na	na

		Emission Factors					Control Equipment				Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		Carbon disulfide	00075-15-0	2.42E-05	lb/ton	PISCES	na	na	na	240.9	5.83E-03	na	na	2.55E-02	na	na
		2-Chloroacetophenone	00532-27-4	7.00E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.69E-03	na	na	7.39E-03	na	na
		Chlorobenzene	00108-90-7	3.52E-06	lb/ton	PISCES	na	na	na	240.9	8.48E-04	na	na	3.71E-03	na	na
		Chloroform	00067-66-3	1.76E-05	lb/ton	PISCES	na	na	na	240.9	4.24E-03	na	na	1.86E-02	na	na
		Cumene	00098-82-8	5.30E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.28E-03	na	na	5.59E-03	na	na
		Cyanide	00057-12-5	2.50E-03	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	6.02E-01	na	na	2.64E+00	na	na
		Dimethyl sulfate	00077-78-1	4.80E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.16E-02	na	na	5.06E-02	na	na
		2,4-Dinitrotoluene	00121-14-2	4.40E-06	lb/ton	PISCES	na	na	na	240.9	1.06E-03	na	na	4.64E-03	na	na
		Ethylbenzene	00100-41-4	1.76E-05	lb/ton	PISCES	na	na	na	240.9	4.24E-03	na	na	1.86E-02	na	na
		Ethyl chloride	00075-00-3	4.20E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.01E-02	na	na	4.43E-02	na	na
		Ethylene dibromide	00106-93-4	1.20E-06	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	2.89E-04	na	na	1.27E-03	na	na
		Ethylene dichloride	00107-06-2	4.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	9.64E-03	na	na	4.22E-02	na	na
		Formaldehyde	00050-00-0	5.72E-05	lb/ton	PISCES	na	na	na	240.9	1.38E-02	na	na	6.04E-02	na	na
		Hexane	00110-54-3	6.70E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.61E-02	na	na	7.07E-02	na	na
		Isophorone	00078-59-1	2.64E-05	lb/ton	PISCES	na	na	na	240.9	6.36E-03	na	na	2.79E-02	na	na
		Methyl bromide	00074-83-9	1.60E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	3.85E-02	na	na	1.69E-01	na	na
		Methyl chloride	00074-87-3	5.30E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	1.28E-01	na	na	5.59E-01	na	na
		Methyl ethyl ketone	00078-93-3	3.90E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	9.40E-02	na	na	4.12E-01	na	na
		Methyl hydrazine	00060-34-4	1.70E-04	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	4.10E-02	na	na	1.79E-01	na	na
		Methyl methacrylate	00080-62-6	2.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	4.82E-03	na	na	2.11E-02	na	na
		Methyl tert butyl ether	01634-04-4	3.50E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	8.43E-03	na	na	3.69E-02	na	na
		Methylene chloride	00075-09-2	7.92E-05	lb/ton	PISCES	na	na	na	240.9	1.91E-02	na	na	8.36E-02	na	na
		Phenol	00108-95-2	7.26E-05	lb/ton	PISCES	na	na	na	240.9	1.75E-02	na	na	7.66E-02	na	na
		Propionaldehyde	00123-38-6	4.18E-05	lb/ton	PISCES	na	na	na	240.9	1.01E-02	na	na	4.41E-02	na	na
		Styrene	00100-42-5	1.54E-05	lb/ton	PISCES	na	na	na	240.9	3.71E-03	na	na	1.62E-02	na	na
		Tetrachloroethylene	00127-18-4	9.24E-06	lb/ton	PISCES	na	na	na	240.9	2.23E-03	na	na	9.75E-03	na	na
		Toluene	00108-88-3	3.74E-05	lb/ton	PISCES	na	na	na	240.9	9.01E-03	na	na	3.95E-02	na	na
		1,1,1-Trichloroethane	00079-00-5	2.00E-05	lb/ton	AP42 1.1-14, 9/98	na	na	na	240.9	4.82E-03	na	na	2.11E-02	na	na
		Vinyl acetate	00108-05-4	6.82E-06	lb/ton	PISCES	na	na	na	240.9	1.64E-03	na	na	7.20E-03	na	na
		m/p-Xylene	00108-38-3	1.80E-05	lb/ton	PISCES	na	na	na	240.9	4.35E-03	na	na	1.90E-02	na	na
		o-Xylene	00095-47-6	9.68E-06	lb/ton	PISCES	na	na	na	240.9	2.33E-03	na	na	1.02E-02	na	na
		POM	na	5.28E-05	lb/ton	AP42 1.1-17, 9/98	na	na	na	240.9	1.27E-02	na	na	5.57E-02	na	na
		Hydrogen Chloride	07647-01-0	1.44E+00	lb/ton	PISCES	C03D	PJFF, DSI, FGD	80.8%	240.9	346.9	66.4	na	1,519.3	291.0	na

		Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
		Hydrogen Fluoride	07664-39-3	1.68E-01	lb/ton	PISCES	C03D	PJFF, DSI, FGD	86.9%	240.9	40.6	5.3	na	177.8	23.3	na

KyEIS ID #	Process ID(s)	Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
07		Coal Handling Operations 07														
07	1	West Track Hopper														
		PM	na	0.00040	lb/ton	MRI; 1996 Title V App	C07A	Enclosures	90%	820	0.328	0.033	na	1.437	0.144	na
		PM10	na	0.00040	lb/ton	MRI; 1996 Title V App	C07A	Enclosures	90%	820	0.328	0.033	na	1.437	0.144	na
		PM2.5	na	0.00008	lb/ton	Estimated 20% of PM10	C07A	Enclosures	90%	820	0.066	0.007	na	0.287	0.029	na
07	2	Conveyor A-1														
		PM	na	0.00030	lb/ton	MRI; 1996 Title V App	C07B	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM10	na	0.00030	lb/ton	MRI; 1996 Title V App	C07B	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM2.5	na	0.00006	lb/ton	Estimated 20% of PM10	C07B	Enclosures	90%	820	0.049	0.005	na	0.215	0.022	na
07	3	Conveyor E														
		PM	na	0.00030	lb/ton	MRI; 1996 Title V App	C07C	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM10	na	0.00030	lb/ton	MRI; 1996 Title V App	C07C	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM2.5	na	0.00006	lb/ton	Estimated 20% of PM10	C07C	Enclosures	90%	820	0.049	0.005	na	0.215	0.022	na
07	4	Conveyor F														
		PM	na	0.00030	lb/ton	MRI; 1996 Title V App	C07D	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM10	na	0.00030	lb/ton	MRI; 1996 Title V App	C07D	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM2.5	na	0.00006	lb/ton	Estimated 20% of PM10	C07D	Enclosures	90%	820	0.049	0.005	na	0.215	0.022	na
07	5	Conveyor G														
		PM	na	0.00030	lb/ton	MRI; 1996 Title V App	C07E	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM10	na	0.00030	lb/ton	MRI; 1996 Title V App	C07E	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM2.5	na	0.00006	lb/ton	Estimated 20% of PM10	C07E	Enclosures	90%	820	0.049	0.005	na	0.215	0.022	na
07	6	Conveyor H														
		PM	na	0.00030	lb/ton	MRI; 1996 Title V App	C07F	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM10	na	0.00030	lb/ton	MRI; 1996 Title V App	C07F	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM2.5	na	0.00006	lb/ton	Estimated 20% of PM10	C07F	Enclosures	90%	820	0.049	0.005	na	0.215	0.022	na

		Emission Factors				Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
09		Coal Handling Operations 09													
09	1	East Track Hopper													
		PM	na	0.00040 lb/ton	MRI; 1996 Title V App	C09A	Enclosures	90%	820	0.328	0.033	na	1.437	0.144	na
		PM10	na	0.00040 lb/ton	MRI; 1996 Title V App	C09A	Enclosures	90%	820	0.328	0.033	na	1.437	0.144	na
		PM2.5	na	0.00008 lb/ton	Estimated 20% of PM10	C09A	Enclosures	90%	820	0.066	0.007	na	0.287	0.029	na
09	2	Conveyor A													
		PM	na	0.00030 lb/ton	MRI; 1996 Title V App	C09B	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM10	na	0.00030 lb/ton	MRI; 1996 Title V App	C09B	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM2.5	na	0.00006 lb/ton	Estimated 20% of PM10	C09B	Enclosures	90%	820	0.049	0.005	na	0.215	0.022	na
09	3	Conveyor B													
		PM	na	0.00030 lb/ton	MRI; 1996 Title V App	C09C	Enclosures	90%	1,640	0.492	0.049	na	2.155	0.215	na
		PM10	na	0.00030 lb/ton	MRI; 1996 Title V App	C09C	Enclosures	90%	1,640	0.492	0.049	na	2.155	0.215	na
		PM2.5	na	0.00006 lb/ton	Estimated 20% of PM10	C09C	Enclosures	90%	1,640	0.098	0.010	na	0.431	0.043	na
09	4	Conveyor C													
		PM	na	0.00030 lb/ton	MRI; 1996 Title V App	C09D	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM10	na	0.00030 lb/ton	MRI; 1996 Title V App	C09D	Enclosures	90%	820	0.246	0.025	na	1.077	0.108	na
		PM2.5	na	0.00006 lb/ton	Estimated 20% of PM10	C09D	Enclosures	90%	820	0.049	0.005	na	0.215	0.022	na
09	5	Conveyor J													
		PM	na	0.00030 lb/ton	MRI; 1996 Title V App	C09E	Enclosures	90%	1,640	0.492	0.049	na	2.155	0.215	na
		PM10	na	0.00030 lb/ton	MRI; 1996 Title V App	C09E	Enclosures	90%	1,640	0.492	0.049	na	2.155	0.215	na
		PM2.5	na	0.00006 lb/ton	Estimated 20% of PM10	C09E	Enclosures	90%	1,640	0.098	0.010	na	0.431	0.043	na
09	6	Coal Stockpile													
		PM	na	0.00180 lb/ton	AP42 & EPA450/3-88-008	C09F	Compaction	70%	1,640	2.948	0.884	na	12.913	3.874	na
		PM10	na	0.00086 lb/ton	Estimated 50% of PM	C09F	Compaction	70%	1,640	1.408	0.422	na	6.166	1.850	na
		PM2.5	na	0.00017 lb/ton	Estimated 20% of PM	C09F	Compaction	70%	1,640	0.275	0.083	na	1.205	0.362	na

		Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
13		Coal Handling Operations 13														
13	1	Conveyor D [Tripper for Units 1 & 2]														
		PM	na	0.04190	lb/ton	MRI; 1996 Title V App	C13A	Cyclone	92%	820	34.358	2.749	75.0	150.488	12.039	na
		PM10	na	0.04190	lb/ton	MRI; 1996 Title V App	C13A	Cyclone	92%	820	34.358	2.749	75.0	150.488	12.039	na
		PM2.5	na	0.00838	lb/ton	Estimated 20% of PM10	C13A	Cyclone	92%	820	6.872	0.550	75.0	30.098	2.408	na
13	2	Conveyor K-1 [Upper Tripper for Unit 3]														
		PM	na	0.02800	lb/ton	MRI; 1996 Title V App	C13B	Fabric Filter	99.5%	820	22.960	0.115	75.0	100.565	0.503	na
		PM10	na	0.02800	lb/ton	MRI; 1996 Title V App	C13B	Fabric Filter	99.5%	820	22.960	0.115	75.0	100.565	0.503	na
		PM2.5	na	0.00560	lb/ton	Estimated 20% of PM10	C13B	Fabric Filter	99.5%	820	4.592	0.023	75.0	20.113	0.101	na
13	3	Conveyor K [Lower Tripper for Unit 3]														
		PM	na	0.02800	lb/ton	MRI; 1996 Title V App	C13C	Fabric Filter	99.5%	820	22.960	0.115	75.0	100.565	0.503	na
		PM10	na	0.02800	lb/ton	MRI; 1996 Title V App	C13C	Fabric Filter	99.5%	820	22.960	0.115	75.0	100.565	0.503	na
		PM2.5	na	0.00560	lb/ton	Estimated 20% of PM10	C13C	Fabric Filter	99.5%	820	4.592	0.023	75.0	20.113	0.101	na
16		Coal Crushing														
16	1	Four Crushers and Crusher House														
		PM	na	0.02000	lb/ton	MRI; 1996 Title V App	C16	Wet Scrubber	99%	1,640	32.800	0.328	84.2	143.664	1.437	na
		PM10	na	0.01000	lb/ton	MRI; 1996 Title V App	C16	Wet Scrubber	99%	1,640	16.400	0.164	84.2	71.832	0.718	na
		PM2.5	na	0.00200	lb/ton	Estimated 20% of PM10	C16	Wet Scrubber	99%	1,640	3.280	0.033	84.2	14.366	0.144	na
21		Dry Fly Ash Handling														
21	1	Dry Fly Ash Collection and Silo														
		PM	na	3.0	lb/ton	MRI; 1996 Title V App	C21	Fabric Filter	99.9%	79.5	238.5	0.24	34.9	1,044.6	1.04	na
		PM10	na	3.0	lb/ton	MRI; 1996 Title V App	C21	Fabric Filter	99.9%	79.5	238.5	0.24	34.9	1,044.6	1.04	na
		PM2.5	na	0.6	lb/ton	Estimated 20% of PM10	C21	Fabric Filter	99.9%	79.5	47.7	0.05	34.9	208.9	0.21	na

KyEIS ID #	Process ID(s)	Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
23		Combustion Turbine Unit 9														
23	1	Fuel: Distillate Oil														
		CO	00630-08-0	0.459	lb/1000 gal	AP42 Table 3.1-1 (4/2000)	na	na	na	9.913	4.5	na	75.0	5.7	na	93.8
		NOX	10102-44-0	24.36	lb/1000 gal	Manufacturer	C23	Water Inject	65%	9.913	241.5	84.5	na	301.9	105.6	na
		SO2	07446-09-5	7.02	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	69.6	na	444.0	87.0	na	na
		VOC	na	0.057	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	0.56	na	20.4	0.71	na	25.5
		PM	na	1.668	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	16.5	na	67.0	20.7	na	83.8
		PM10	na	1.668	lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		PM2.5	na	1.668	lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		Lead	07439-92-1	0.0012	lb/1000 gal	EPA TAP EF Compilation	na	na	na	9.913	0.0	na	na	0.0	na	na
		CO_2E	#N/A	22578.4206	lb/1000 gal	40 CFR 98 Subpart C	na	na	na	9.913	223,820.9	na	na	279,776.1	na	na
		1,3-Butadiene	00106-99-0	2.22E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	2.20E-02	na	na	2.76E-02	na	na
		Benzene	00071-43-2	7.65E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	7.58E-02	na	na	9.47E-02	na	na
		Formaldehyde	00050-00-0	3.89E-02	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	3.86E-01	na	na	4.82E-01	na	na
		Naphthalene	00091-20-3	4.87E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	4.82E-02	na	na	6.03E-02	na	na
		PAH	na	5.56E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	5.51E-02	na	na	6.89E-02	na	na
																na
		Arsenic	07740-38-2	1.53E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Beryllium	07440-41-7	4.50E-05	lb/1000 gal	EPA 450/2-90-011	na	na	na	9.913	4.46E-04	na	3.37E-03	5.58E-04	na	4.21E-03
		Cadmium	07440-43-9	6.67E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.61E-03	na	na	8.27E-03	na	na
		Chromium	07440-47-3	1.53E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Manganese	07439-96-5	1.10E-01	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.09E+00	na	na	1.36E+00	na	na
		Mercury	07439-97-6	1.67E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.65E-03	na	na	2.07E-03	na	na
		Nickel	07440-02-0	6.39E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.34E-03	na	na	7.92E-03	na	na
		Selenium	07782-49-2	3.48E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	3.44E-02	na	na	4.31E-02	na	na

		Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
23		Combustion Turbine Unit 9														
23	2	Fuel: Natural Gas														
		CO	00630-08-0	43.0	lb/MMcf	Manufacture	na	na	na	1.341	57.7	na	75.0	252.6	na	93.8
		NOX	10102-44-0	115.92	lb/MMcf	Manufacturer	C23	Water Inject	65%	1.341	155.5	54.4	na	681.0	238.3	na
		SO2	07446-09-5	0.08	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	0.11	na	444.0	0.49	na	na
		VOC	na	2.142	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	2.87	na	20.4	12.58	na	25.5
		PM	na	6.732	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	9.0	na	67.0	39.5	na	83.8
		PM10	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		PM2.5	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		CO_2E	#N/A	119438.826	lb/MMcf	40 CFR 98 Subpart C	na	na	na	1.341	160,188.5	na	na	701,625.8	na	na
		1,3-Butadiene	00106-99-0	4.39E-04	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.88E-04	na	na	2.58E-03	na	na
		Acetaldehyde	00075-07-0	4.08E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.47E-02	na	na	2.40E-01	na	na
		Acrolein	00107-02-8	6.53E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-03	na	na	3.83E-02	na	na
		Benzene	00071-43-2	1.22E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.64E-02	na	na	7.19E-02	na	na
		Ethylbenzene	00100-41-4	3.26E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	4.38E-02	na	na	1.92E-01	na	na
		Formaldehyde	00050-00-0	7.24E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	9.71E-01	na	na	4.25E+00	na	na
		Naphthalene	00091-20-3	1.33E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-03	na	na	7.79E-03	na	na
		PAH	na	2.24E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.01E-03	na	na	1.32E-02	na	na
		Propylene Oxide	00075-56-9	2.96E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.97E-02	na	na	1.74E-01	na	na
		Toluene	00108-88-3	1.33E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-01	na	na	7.79E-01	na	na
		Xylenes	01330-20-7	6.53E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-02	na	na	3.83E-01	na	na

KyEIS ID #	Process ID(s)	Pollutant	CAS#	Emission Factors: Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
24		Combustion Turbine Unit 10														
24	1	Fuel: Distillate Oil														
		CO	00630-08-0	0.459	lb/1000 gal	AP42 Table 3.1-1 (4/2000)	na	na	na	9.913	4.5	na	75.0	5.7	na	93.8
		NOX	10102-44-0	24.36	lb/1000 gal	Manufacturer	C24	Water Inject	65%	9.913	241.5	84.5	na	301.9	105.6	na
		SO2	07446-09-5	7.02	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	69.6	na	444.0	87.0	na	na
		VOC	na	0.057	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	0.56	na	20.4	0.71	na	25.5
		PM	na	1.668	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	16.5	na	67.0	20.7	na	83.8
		PM10	na	1.668	lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		PM2.5	na	1.668	lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		Lead	07439-92-1	0.0012	lb/1000 gal	EPA TAP EF Compilation	na	na	na	9.913	0.0	na	na	0.0	na	na
		CO_2E	#N/A	22578.4206	lb/1000 gal	40 CFR 98 Subpart C	na	na	na	9.913	223,820.9	na	na	279,776.1	na	na
		1,3-Butadiene	00106-99-0	2.22E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	2.20E-02	na	na	2.76E-02	na	na
		Benzene	00071-43-2	7.65E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	7.58E-02	na	na	9.47E-02	na	na
		Formaldehyde	00050-00-0	3.89E-02	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	3.86E-01	na	na	4.82E-01	na	na
		Naphthalene	00091-20-3	4.87E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	4.82E-02	na	na	6.03E-02	na	na
		PAH	na	5.56E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	5.51E-02	na	na	6.89E-02	na	na
																na
		Arsenic	07740-38-2	1.53E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Beryllium	07440-41-7	4.50E-05	lb/1000 gal	EPA 450/2-90-011	na	na	na	9.913	4.46E-04	na	3.37E-03	5.58E-04	na	4.21E-03
		Cadmium	07440-43-9	6.67E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.61E-03	na	na	8.27E-03	na	na
		Chromium	07440-47-3	1.53E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Manganese	07439-96-5	1.10E-01	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.09E+00	na	na	1.36E+00	na	na
		Mercury	07439-97-6	1.67E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.65E-03	na	na	2.07E-03	na	na
		Nickel	07440-02-0	6.39E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.34E-03	na	na	7.92E-03	na	na
		Selenium	07782-49-2	3.48E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	3.44E-02	na	na	4.31E-02	na	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
24		Combustion Turbine Unit 10														
24	2	Fuel: Natural Gas														
		CO	00630-08-0	43.0	lb/MMcf	Manufacture	na	na	na	1.341	57.7	na	75.0	252.6	na	93.8
		NOX	10102-44-0	115.92	lb/MMcf	Manufacturer	C24	Water Inject	65%	1.341	155.5	54.4	na	681.0	238.3	na
		SO2	07446-09-5	0.08	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	0.11	na	444.0	0.49	na	na
		VOC	na	2.142	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	2.87	na	20.4	12.58	na	25.5
		PM	na	6.732	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	9.0	na	67.0	39.5	na	83.8
		PM10	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		PM2.5	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		CO_2E	#N/A	119438.826	lb/MMcf	40 CFR 98 Subpart C	na	na	na	1.341	160,188.5	na	na	701,625.8	na	na
		1,3-Butadiene	00106-99-0	4.39E-04	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.88E-04	na	na	2.58E-03	na	na
		Acetaldehyde	00075-07-0	4.08E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.47E-02	na	na	2.40E-01	na	na
		Acrolein	00107-02-8	6.53E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-03	na	na	3.83E-02	na	na
		Benzene	00071-43-2	1.22E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.64E-02	na	na	7.19E-02	na	na
		Ethylbenzene	00100-41-4	3.26E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	4.38E-02	na	na	1.92E-01	na	na
		Formaldehyde	00050-00-0	7.24E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	9.71E-01	na	na	4.25E+00	na	na
		Naphthalene	00091-20-3	1.33E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-03	na	na	7.79E-03	na	na
		PAH	na	2.24E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.01E-03	na	na	1.32E-02	na	na
		Propylene Oxide	00075-56-9	2.96E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.97E-02	na	na	1.74E-01	na	na
		Toluene	00108-88-3	1.33E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-01	na	na	7.79E-01	na	na
		Xylenes	01330-20-7	6.53E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-02	na	na	3.83E-01	na	na

		Emission Factors				Control Equipment				Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
25		Combustion Turbine Unit 8													
25	1	Fuel: Distillate Oil													
		CO	00630-08-0	0.459 lb/1000 gal	AP42 Table 3.1-1 (4/2000)	na	na	na	9.913	4.5	na	75.0	5.7	na	93.8
		NOX	10102-44-0	24.36 lb/1000 gal	Manufacturer	C25	Water Inject	65%	9.913	241.5	84.5	na	301.9	105.6	na
		SO2	07446-09-5	7.02 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	69.6	na	444.0	87.0	na	na
		VOC	na	0.057 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	0.56	na	20.4	0.71	na	25.5
		PM	na	1.668 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	16.5	na	67.0	20.7	na	83.8
		PM10	na	1.668 lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		PM2.5	na	1.668 lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		Lead	07439-92-1	0.0012 lb/1000 gal	EPA TAP EF Compilation	na	na	na	9.913	0.0	na	na	0.0	na	na
		CO_2E	#N/A	22578.4206 lb/1000 gal	40 CFR 98 Subpart C	na	na	na	9.913	223,820.9	na	na	279,776.1	na	na
		1,3-Butadiene	00106-99-0	2.22E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	2.20E-02	na	na	2.76E-02	na	na
		Benzene	00071-43-2	7.65E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	7.58E-02	na	na	9.47E-02	na	na
		Formaldehyde	00050-00-0	3.89E-02 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	3.86E-01	na	na	4.82E-01	na	na
		Naphthalene	00091-20-3	4.87E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	4.82E-02	na	na	6.03E-02	na	na
		PAH	na	5.56E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	5.51E-02	na	na	6.89E-02	na	na
															na
		Arsenic	07740-38-2	1.53E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Beryllium	07440-41-7	4.50E-05 lb/1000 gal	EPA 450/2-90-011	na	na	na	9.913	4.46E-04	na	3.37E-03	5.58E-04	na	4.21E-03
		Cadmium	07440-43-9	6.67E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.61E-03	na	na	8.27E-03	na	na
		Chromium	07440-47-3	1.53E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Manganese	07439-96-5	1.10E-01 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.09E+00	na	na	1.36E+00	na	na
		Mercury	07439-97-6	1.67E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.65E-03	na	na	2.07E-03	na	na
		Nickel	07440-02-0	6.39E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.34E-03	na	na	7.92E-03	na	na
		Selenium	07782-49-2	3.48E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	3.44E-02	na	na	4.31E-02	na	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
25		Combustion Turbine Unit 8														
25	2	Fuel: Natural Gas														
		CO	00630-08-0	43.0	lb/MMcf	Manufacture	na	na	na	1.341	57.7	na	75.0	252.6	na	93.8
		NOX	10102-44-0	115.92	lb/MMcf	Manufacturer	C25	Water Inject	65%	1.341	155.5	54.4	na	681.0	238.3	na
		SO2	07446-09-5	0.08	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	0.11	na	444.0	0.49	na	na
		VOC	na	2.142	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	2.87	na	20.4	12.58	na	25.5
		PM	na	6.732	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	9.0	na	67.0	39.5	na	83.8
		PM10	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		PM2.5	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		CO_2E	#N/A	119438.826	lb/MMcf	40 CFR 98 Subpart C	na	na	na	1.341	160,188.5	na	na	701,625.8	na	na
		1,3-Butadiene	00106-99-0	4.39E-04	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.88E-04	na	na	2.58E-03	na	na
		Acetaldehyde	00075-07-0	4.08E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.47E-02	na	na	2.40E-01	na	na
		Acrolein	00107-02-8	6.53E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-03	na	na	3.83E-02	na	na
		Benzene	00071-43-2	1.22E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.64E-02	na	na	7.19E-02	na	na
		Ethylbenzene	00100-41-4	3.26E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	4.38E-02	na	na	1.92E-01	na	na
		Formaldehyde	00050-00-0	7.24E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	9.71E-01	na	na	4.25E+00	na	na
		Naphthalene	00091-20-3	1.33E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-03	na	na	7.79E-03	na	na
		PAH	na	2.24E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.01E-03	na	na	1.32E-02	na	na
		Propylene Oxide	00075-56-9	2.96E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.97E-02	na	na	1.74E-01	na	na
		Toluene	00108-88-3	1.33E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-01	na	na	7.79E-01	na	na
		Xylenes	01330-20-7	6.53E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-02	na	na	3.83E-01	na	na

KyEIS ID #	Process ID(s)	Emission Factors				Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
26		Combustion Turbine Unit 11													
26	1	Fuel: Distillate Oil													
		CO	00630-08-0	0.459 lb/1000 gal	AP42 Table 3.1-1 (4/2000)	na	na	na	9.913	4.5	na	75.0	5.7	na	93.8
		NOX	10102-44-0	24.36 lb/1000 gal	Manufacturer	C26	Water Inject	65%	9.913	241.5	84.5	na	301.9	105.6	na
		SO2	07446-09-5	7.02 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	69.6	na	444.0	87.0	na	na
		VOC	na	0.057 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	0.56	na	20.4	0.71	na	25.5
		PM	na	1.668 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	9.913	16.5	na	67.0	20.7	na	83.8
		PM10	na	1.668 lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		PM2.5	na	1.668 lb/1000 gal	Assume all PM is PM2.5	na	na	na	9.913	16.5	na	na	20.7	na	na
		Lead	07439-92-1	0.0012 lb/1000 gal	EPA TAP EF Compilation	na	na	na	9.913	0.0	na	na	0.0	na	na
		CO_2E	#N/A	22578.4206 #N/A	40 CFR 98 Subpart C	na	na	na	#N/A	223,820.9	na	na	279,776.1	na	na
		1,3-Butadiene	00106-99-0	2.22E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	2.20E-02	na	na	2.76E-02	na	na
		Benzene	00071-43-2	7.65E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	7.58E-02	na	na	9.47E-02	na	na
		Formaldehyde	00050-00-0	3.89E-02 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	3.86E-01	na	na	4.82E-01	na	na
		Naphthalene	00091-20-3	4.87E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	4.82E-02	na	na	6.03E-02	na	na
		PAH	na	5.56E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	9.913	5.51E-02	na	na	6.89E-02	na	na
															na
		Arsenic	07740-38-2	1.53E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Beryllium	07440-41-7	4.50E-05 lb/1000 gal	EPA 450/2-90-011	na	na	na	9.913	4.46E-04	na	3.37E-03	5.58E-04	na	4.21E-03
		Cadmium	07440-43-9	6.67E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.61E-03	na	na	8.27E-03	na	na
		Chromium	07440-47-3	1.53E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.52E-02	na	na	1.89E-02	na	na
		Manganese	07439-96-5	1.10E-01 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.09E+00	na	na	1.36E+00	na	na
		Mercury	07439-97-6	1.67E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	1.65E-03	na	na	2.07E-03	na	na
		Nickel	07440-02-0	6.39E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	6.34E-03	na	na	7.92E-03	na	na
		Selenium	07782-49-2	3.48E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	9.913	3.44E-02	na	na	4.31E-02	na	na

		Emission Factors				Control Equipment				Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
26		Combustion Turbine Unit 11													
26	2	Fuel: Natural Gas													
		CO	00630-08-0	43.0 lb/MMcf	Manufacture	na	na	na	1.341	57.7	na	75.0	252.6	na	93.8
		NOX	10102-44-0	115.92 lb/MMcf	Manufacturer	C26	Water Inject	65%	1.341	155.5	54.4	na	681.0	238.3	na
		SO2	07446-09-5	0.08 lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	0.11	na	444.0	0.49	na	na
		VOC	na	2.142 lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	2.87	na	20.4	12.58	na	25.5
		PM	na	6.732 lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	9.0	na	67.0	39.5	na	83.8
		PM10	na	6.732 lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		PM2.5	na	6.732 lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		CO_2E	#N/A	119438.826 lb/MMcf	40 CFR 98 Subpart C	na	na	na	1.341	160,188.5	na	na	701,625.8	na	na
		1,3-Butadiene	00106-99-0	4.39E-04 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.88E-04	na	na	2.58E-03	na	na
		Acetaldehyde	00075-07-0	4.08E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.47E-02	na	na	2.40E-01	na	na
		Acrolein	00107-02-8	6.53E-03 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-03	na	na	3.83E-02	na	na
		Benzene	00071-43-2	1.22E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.64E-02	na	na	7.19E-02	na	na
		Ethylbenzene	00100-41-4	3.26E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	4.38E-02	na	na	1.92E-01	na	na
		Formaldehyde	00050-00-0	7.24E-01 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	9.71E-01	na	na	4.25E+00	na	na
		Naphthalene	00091-20-3	1.33E-03 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-03	na	na	7.79E-03	na	na
		PAH	na	2.24E-03 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.01E-03	na	na	1.32E-02	na	na
		Propylene Oxide	00075-56-9	2.96E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.97E-02	na	na	1.74E-01	na	na
		Toluene	00108-88-3	1.33E-01 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-01	na	na	7.79E-01	na	na
		Xylenes	01330-20-7	6.53E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-02	na	na	3.83E-01	na	na

		Emission Factors				Control Equipment				Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
27		Combustion Turbine Unit 6													
27	1	Fuel: Distillate Oil													
		CO	00630-08-0	0.459 lb/1000 gal	AP42 Table 3.1-1 (4/2000)	na	na	na	12.159	5.6	na	112.5	7.0	na	140.6
		NOX	10102-44-0	27.3 lb/1000 gal	Manufacturer	C27	Water Inject	65%	12.159	332.0	116.2	na	414.9	145.2	na
		SO2	07446-09-5	32.29 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	12.159	392.6	na	666.0	490.8	na	na
		VOC	na	0.057 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	12.159	0.69	na	30.6	0.87	na	38.3
		PM	na	1.668 lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	12.159	20.3	na	100.5	25.4	na	125.6
		PM10	na	1.668 lb/1000 gal	Assume all PM is PM2.5	na	na	na	12.159	20.3	na	na	25.4	na	na
		PM2.5	na	1.668 lb/1000 gal	Assume all PM is PM2.5	na	na	na	12.159	20.3	na	na	25.4	na	na
		Lead	07439-92-1	0.0012 lb/1000 gal	EPA TAP EF Compilation	na	na	na	12.159	0.0	na	na	0.0	na	na
		CO_2E	#N/A	22578.4206 lb/1000 gal	40 CFR 98 Subpart C	na	na	na	12.159	274,540.5	na	na	343,175.6	na	na
		1,3-Butadiene	00106-99-0	2.22E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	2.70E-02	na	na	3.38E-02	na	na
		Benzene	00071-43-2	7.65E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	9.30E-02	na	na	1.16E-01	na	na
		Formaldehyde	00050-00-0	3.89E-02 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	4.73E-01	na	na	5.92E-01	na	na
		Naphthalene	00091-20-3	4.87E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	5.92E-02	na	na	7.39E-02	na	na
		PAH	na	5.56E-03 lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	6.76E-02	na	na	8.45E-02	na	na
															na
		Arsenic	07740-38-2	1.53E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	1.86E-02	na	na	2.32E-02	na	na
		Beryllium	07440-41-7	4.50E-05 lb/1000 gal	EPA 450/2-90-011	na	na	na	12.159	5.48E-04	na	5.06E-03	6.85E-04	na	6.35E-03
		Cadmium	07440-43-9	6.67E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	8.11E-03	na	na	1.01E-02	na	na
		Chromium	07440-47-3	1.53E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	1.86E-02	na	na	2.32E-02	na	na
		Manganese	07439-96-5	1.10E-01 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	1.34E+00	na	na	1.67E+00	na	na
		Mercury	07439-97-6	1.67E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	2.03E-03	na	na	2.54E-03	na	na
		Nickel	07440-02-0	6.39E-04 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	7.77E-03	na	na	9.72E-03	na	na
		Selenium	07782-49-2	3.48E-03 lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	4.23E-02	na	na	5.28E-02	na	na

		Emission Factors				Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
27		Combustion Turbine Unit 6													
27	2	Fuel: Natural Gas													
		CO	00630-08-0	43.0 lb/MMcf	Manufacture	na	na	na	1.645	70.7	na	112.5	309.8	na	140.6
		NOX	10102-44-0	99.54 lb/MMcf	Manufacturer	C27	Water Inject	65%	1.645	163.8	57.3	na	717.2	251.0	na
		SO2	07446-09-5	0.08 lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.645	0.14	na	666.0	0.60	na	na
		VOC	na	2.142 lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.645	3.52	na	30.6	15.43	na	38.3
		PM	na	6.732 lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.645	11.1	na	100.5	48.5	na	125.6
		PM10	na	6.732 lb/MMcf	Assume all PM is PM2.5	na	na	na	1.645	11.1	na	na	48.5	na	na
		PM2.5	na	6.732 lb/MMcf	Assume all PM is PM2.5	na	na	na	1.645	11.1	na	na	48.5	na	na
		CO_2E	#N/A	119438.826 lb/MMcf	40 CFR 98 Subpart C	na	na	na	1.645	196,488.6	na	na	860,620.0	na	na
		1,3-Butadiene	00106-99-0	4.39E-04 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	7.22E-04	na	na	3.16E-03	na	na
		Acetaldehyde	00075-07-0	4.08E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	6.71E-02	na	na	2.94E-01	na	na
		Acrolein	00107-02-8	6.53E-03 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	1.07E-02	na	na	4.70E-02	na	na
		Benzene	00071-43-2	1.22E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	2.01E-02	na	na	8.82E-02	na	na
		Ethylbenzene	00100-41-4	3.26E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	5.37E-02	na	na	2.35E-01	na	na
		Formaldehyde	00050-00-0	7.24E-01 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	1.19E+00	na	na	5.22E+00	na	na
		Naphthalene	00091-20-3	1.33E-03 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	2.18E-03	na	na	9.55E-03	na	na
		PAH	na	2.24E-03 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	3.69E-03	na	na	1.62E-02	na	na
		Propylene Oxide	00075-56-9	2.96E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	4.87E-02	na	na	2.13E-01	na	na
		Toluene	00108-88-3	1.33E-01 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	2.18E-01	na	na	9.55E-01	na	na
		Xylenes	01330-20-7	6.53E-02 lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	1.07E-01	na	na	4.70E-01	na	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
28		Combustion Turbine Unit 7														
28	1	Fuel: Distillate Oil														
		CO	00630-08-0	0.459	lb/1000 gal	AP42 Table 3.1-1 (4/2000)	na	na	na	12.159	5.6	na	112.5	7.0	na	140.6
		NOX	10102-44-0	27.3	lb/1000 gal	Manufacturer	C28	Water Inject	65%	12.159	332.0	116.2	na	414.9	145.2	na
		SO2	07446-09-5	32.29	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	12.159	392.6	na	666.0	490.8	na	na
		VOC	na	0.057	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	12.159	0.69	na	30.6	0.87	na	38.3
		PM	na	1.668	lb/1000 gal	AP42 Table 3.1-2a (4/2000)	na	na	na	12.159	20.3	na	100.5	25.4	na	125.6
		PM10	na	1.668	lb/1000 gal	Assume all PM is PM2.5	na	na	na	12.159	20.3	na	na	25.4	na	na
		PM2.5	na	1.668	lb/1000 gal	Assume all PM is PM2.5	na	na	na	12.159	20.3	na	na	25.4	na	na
		Lead	07439-92-1	0.0012	lb/1000 gal	EPA TAP EF Compilation	na	na	na	12.159	0.0	na	na	0.0	na	na
		CO_2E	#N/A	22578.4206	lb/1000 gal	40 CFR 98 Subpart C	na	na	na	12.159	274,540.5	na	na	343,175.6	na	na
		1,3-Butadiene	00106-99-0	2.22E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	2.70E-02	na	na	3.38E-02	na	na
		Benzene	00071-43-2	7.65E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	9.30E-02	na	na	1.16E-01	na	na
		Formaldehyde	00050-00-0	3.89E-02	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	4.73E-01	na	na	5.92E-01	na	na
		Naphthalene	00091-20-3	4.87E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	5.92E-02	na	na	7.39E-02	na	na
		PAH	na	5.56E-03	lb/1000 gal	AP42 Tbl 3.1-4	na	na	na	12.159	6.76E-02	na	na	8.45E-02	na	na
																na
		Arsenic	07740-38-2	1.53E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	1.86E-02	na	na	2.32E-02	na	na
		Beryllium	07440-41-7	4.50E-05	lb/1000 gal	EPA 450/2-90-011	na	na	na	12.159	5.48E-04	na	na	6.85E-04	na	na
		Cadmium	07440-43-9	6.67E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	8.11E-03	na	na	1.01E-02	na	na
		Chromium	07440-47-3	1.53E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	1.86E-02	na	na	2.32E-02	na	na
		Manganese	07439-96-5	1.10E-01	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	1.34E+00	na	na	1.67E+00	na	na
		Mercury	07439-97-6	1.67E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	2.03E-03	na	na	2.54E-03	na	na
		Nickel	07440-02-0	6.39E-04	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	7.77E-03	na	na	9.72E-03	na	na
		Selenium	07782-49-2	3.48E-03	lb/1000 gal	AP42 Tbl 3.1-5	na	na	na	12.159	4.23E-02	na	na	5.28E-02	na	na

KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Hourly (lb/hr) Emissions: Controlled Limited Potential	Hourly (lb/hr) Emissions: Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Annual (tons/yr) Emissions: Controlled Limited Potential	Annual (tons/yr) Emissions: Allowable
28		Combustion Turbine Unit 7														
28	2	Fuel: Natural Gas														
		CO	00630-08-0	43.0	lb/MMcf	Manufacture	na	na	na	1.645	70.7	na	112.5	309.8	na	140.6
		NOX	10102-44-0	99.54	lb/MMcf	Manufacturer	C28	Water Inject	65%	1.645	163.8	57.3	na	717.2	251.0	na
		SO2	07446-09-5	0.08	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.645	0.14	na	666.0	0.60	na	na
		VOC	na	2.142	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.645	3.52	na	30.6	15.43	na	38.3
		PM	na	6.732	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.645	11.1	na	100.5	48.5	na	125.6
		PM10	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.645	11.1	na	na	48.5	na	na
		PM2.5	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.645	11.1	na	na	48.5	na	na
		CO_2E	#N/A	119438.826	lb/MMcf	40 CFR 98 Subpart C	na	na	na	1.645	196,488.6	na	na	860,620.0	na	na
		1,3-Butadiene	00106-99-0	4.39E-04	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	7.22E-04	na	na	3.16E-03	na	na
		Acetaldehyde	00075-07-0	4.08E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	6.71E-02	na	na	2.94E-01	na	na
		Acrolein	00107-02-8	6.53E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	1.07E-02	na	na	4.70E-02	na	na
		Benzene	00071-43-2	1.22E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	2.01E-02	na	na	8.82E-02	na	na
		Ethylbenzene	00100-41-4	3.26E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	5.37E-02	na	na	2.35E-01	na	na
		Formaldehyde	00050-00-0	7.24E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	1.19E+00	na	na	5.22E+00	na	na
		Naphthalene	00091-20-3	1.33E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	2.18E-03	na	na	9.55E-03	na	na
		PAH	na	2.24E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	3.69E-03	na	na	1.62E-02	na	na
		Propylene Oxide	00075-56-9	2.96E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	4.87E-02	na	na	2.13E-01	na	na
		Toluene	00108-88-3	1.33E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	2.18E-01	na	na	9.55E-01	na	na
		Xylenes	01330-20-7	6.53E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.645	1.07E-01	na	na	4.70E-01	na	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
29		Combustion Turbine Unit 5														
29	1	Fuel: Natural Gas														
		CO	00630-08-0	43.0	lb/MMcf	Manufacture	na	na	na	1.341	57.7	na	75.0	252.6	na	93.8
		NOX	10102-44-0	115.92	lb/MMcf	Manufacturer	C29	Water Inject	65%	1.341	155.5	54.4	na	681.0	238.3	na
		SO2	07446-09-5	0.08	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	0.11	na	444.0	0.49	na	na
		VOC	na	2.142	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	2.87	na	20.4	12.58	na	25.5
		PM	na	6.732	lb/MMcf	AP42 Table 3.1-2a (4/2000)	na	na	na	1.341	9.0	na	67.0	39.5	na	83.8
		PM10	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		PM2.5	na	6.732	lb/MMcf	Assume all PM is PM2.5	na	na	na	1.341	9.0	na	na	39.5	na	na
		CO_2E	#N/A	119438.826	lb/MMcf	40 CFR 98 Subpart C	na	na	na	1.341	160,188.5	na	na	701,625.8	na	na
		1,3-Butadiene	00106-99-0	4.39E-04	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.88E-04	na	na	2.58E-03	na	na
		Acetaldehyde	00075-07-0	4.08E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	5.47E-02	na	na	2.40E-01	na	na
		Acrolein	00107-02-8	6.53E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-03	na	na	3.83E-02	na	na
		Benzene	00071-43-2	1.22E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.64E-02	na	na	7.19E-02	na	na
		Ethylbenzene	00100-41-4	3.26E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	4.38E-02	na	na	1.92E-01	na	na
		Formaldehyde	00050-00-0	7.24E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	9.71E-01	na	na	4.25E+00	na	na
		Naphthalene	00091-20-3	1.33E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-03	na	na	7.79E-03	na	na
		PAH	na	2.24E-03	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.01E-03	na	na	1.32E-02	na	na
		Propylene Oxide	00075-56-9	2.96E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	3.97E-02	na	na	1.74E-01	na	na
		Toluene	00108-88-3	1.33E-01	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	1.78E-01	na	na	7.79E-01	na	na
		Xylenes	01330-20-7	6.53E-02	lb/MMcf	AP42 Tbl 3.1-3	na	na	na	1.341	8.76E-02	na	na	3.83E-01	na	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
30	1	Limestone Truck Dump Station #1														
		PM	na	0.067	lb/ton	Exit Loading Spec.	C30	Fabric Filter	98.0%	250	16.6	0.33	41.9	72.9	1.46	na
		PM10	na	0.067	lb/ton	Exit Loading Spec.	C30	Fabric Filter	98.0%	250	16.6	0.33	na	72.9	1.46	na
		PM2.5	na	0.013	lb/ton	Estimated 20% of PM10	C30	Fabric Filter	98.0%	250	3.3	0.07	na	14.6	0.29	na
31	1	Limestone Truck Dump Station #2														
		PM	na	0.067	lb/ton	Exit Loading Spec.	C31	Fabric Filter	98.0%	250	16.6	0.33	41.9	72.9	1.46	na
		PM10	na	0.067	lb/ton	Exit Loading Spec.	C31	Fabric Filter	98.0%	250	16.6	0.33	na	72.9	1.46	na
		PM2.5	na	0.013	lb/ton	Estimated 20% of PM10	C31	Fabric Filter	98.0%	250	3.3	0.07	na	14.6	0.29	na
32	1	Limestone Stacking Tube														
		PM	na	0.016	lb/ton	Exit Loading Spec.	C32	Fabric Filter	98.0%	500	8.2	0.16	0.36	36.1	0.72	na
		PM10	na	0.016	lb/ton	Exit Loading Spec.	C32	Fabric Filter	98.0%	500	8.2	0.16	na	36.1	0.72	na
		PM2.5	na	0.003	lb/ton	Estimated 20% of PM10	C32	Fabric Filter	98.0%	500	1.6	0.03	na	7.2	0.14	na
33	1	Limestone Reclaim Conveyor #1														
		PM	na	0.016	lb/ton	Exit Loading Spec.	C33	Fabric Filter	98.0%	500	8.2	0.16	0.36	36.1	0.72	na
		PM10	na	0.016	lb/ton	Exit Loading Spec.	C33	Fabric Filter	98.0%	500	8.2	0.16	na	36.1	0.72	na
		PM2.5	na	0.003	lb/ton	Estimated 20% of PM10	C33	Fabric Filter	98.0%	500	1.6	0.03	na	7.2	0.14	na
34	1	Limestone Reclaim Conveyor #2														
		PM	na	0.016	lb/ton	Exit Loading Spec.	C34	Fabric Filter	98.0%	500	8.2	0.16	0.36	36.1	0.72	na
		PM10	na	0.016	lb/ton	Exit Loading Spec.	C34	Fabric Filter	98.0%	500	8.2	0.16	na	36.1	0.72	na
		PM2.5	na	0.003	lb/ton	Estimated 20% of PM10	C34	Fabric Filter	98.0%	500	1.6	0.03	na	7.2	0.14	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
35	1	Road Fugitives from Truck Traffic on Unpaved and Paved Roads														
		PM	na	1.519	lb/VMT	AP42 13.2.1/13.2.2	na	na	na	4.07	6.17	na	na	27.04	na	na
		PM10	na	0.321	lb/VMT	AP42 13.2.1/13.2.2	na	na	na	4.07	1.31	na	na	5.72	na	na
		PM2.5	na	0.042	lb/VMT	AP42 13.2.1/13.2.2	na	na	na	4.07	0.17	na	na	0.74	na	na
36	1	Unit 1 Cooling Tower with Drift Eliminators														
		PM	na	0.071	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	4.08	0.29	na	na	1.27	na	na
		PM10	na	0.071	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	4.08	0.29	na	na	1.27	na	na
		PM2.5	na	0.071	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	4.08	0.29	na	na	1.27	na	na
37	1	Unit 2 Cooling Tower with Drift Eliminators														
		PM	na	0.063	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	6.00	0.38	na	na	1.66	na	na
		PM10	na	0.063	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	6.00	0.38	na	na	1.66	na	na
		PM2.5	na	0.063	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	6.00	0.38	na	na	1.66	na	na
38	1	Unit 3 Cooling Tower with Drift Eliminators														
		PM	na	0.067	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	10.38	0.70	na	na	3.06	na	na
		PM10	na	0.067	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	10.38	0.70	na	na	3.06	na	na
		PM2.5	na	0.067	lb/MMgal	AP42 13.4 (1/1995)	na	na	na	10.38	0.70	na	na	3.06	na	na

		Emission Factors					Control Equipment				Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
39	1	Dix Dam Crest Gate Emergency Generator														
		NOX	10102-44-0	139.857	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00315	0.440	na	na	0.0220	na	na
		CO	00630-08-0	88.491	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00315	0.278	na	na	0.0139	na	na
		SO2	07446-09-5	1.50E-02	lb/1000gal	AP42 Table 3.3-1; 30 ppb	na	na	na	0.00315	4.73E-05	na	na	2.36E-06	na	na
		PM	na	9.167	lb/1000gal	Assume all PM is PM10	na	na	na	0.00315	0.029	na	na	0.0014	na	na
		PM10	na	9.167	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00315	0.029	na	na	0.0014	na	na
		PM2.5	na	9.167	lb/1000gal	Equal to PM10	na	na	na	0.00315	0.029	na	na	0.0014	na	na
		VOC	na	274.514	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00315	0.864	na	na	0.0432	na	na
		CO2E	#N/A	19420.817	lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.00315	61.099	na	na	3.0550	na	na
40	1	Dix Dam Station Emergency Generator														
		NOX	10102-44-0	611.143	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00685	4.185	na	na	0.2093	na	na
		CO	00630-08-0	131.691	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00685	0.902	na	na	0.0451	na	na
		SO2	07446-09-5	0.209	lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.00685	1.43E-03	na	na	7.16E-05	na	na
		PM	na	43.371	lb/1000gal	Assume all PM is PM10	na	na	na	0.00685	0.297	na	na	0.0149	na	na
		PM10	na	43.371	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00685	0.297	na	na	0.0149	na	na
		PM2.5	na	43.371	lb/1000gal	Equal to PM10	na	na	na	0.00685	0.297	na	na	0.0149	na	na
		VOC	na	49.564	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.00685	0.339	na	na	0.0170	na	na
		Acetaldehyde	00075-07-0	0.106	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	7.25E-04	na	na	3.62E-05	na	na
		Acrolein	00107-02-8	0.013	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	8.74E-05	na	na	4.37E-06	na	na
		Benzene	00071-43-2	0.129	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	8.82E-04	na	na	4.41E-05	na	na
		1,3-Butadiene	00106-99-0	0.005	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	3.69E-05	na	na	1.85E-06	na	na
		Formaldehyde	00050-00-0	0.163	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	1.12E-03	na	na	5.58E-05	na	na
		Naphthalene	00091-20-3	0.012	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	8.01E-05	na	na	4.01E-06	na	na
		Toluene	00108-88-3	0.056	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	3.87E-04	na	na	1.93E-05	na	na
		Xylenes	01330-20-7	0.039	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.00685	2.69E-04	na	na	1.35E-05	na	na
		CO2E	#N/A	22578.421	lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.00685	1.55E+02	na	na	7.73E+00	na	na

		Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
41	1	CT5 Emergency Generator														
		NOX	10102-44-0	611.143	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01562	9.548	na	na	0.4774	na	na
		CO	00630-08-0	131.691	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01562	2.057	na	na	0.1029	na	na
		SO2	07446-09-5	0.209	lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.01562	3.27E-03	na	na	1.63E-04	na	na
		PM	na	43.371	lb/1000gal	Assume all PM is PM10	na	na	na	0.01562	0.678	na	na	0.0339	na	na
		PM10	na	43.371	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01562	0.678	na	na	0.0339	na	na
		PM2.5	na	43.371	lb/1000gal	Equal to PM10	na	na	na	0.01562	0.678	na	na	0.0339	na	na
		VOC	na	49.564	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01562	0.774	na	na	0.0387	na	na
		Acetaldehyde	00075-07-0	0.106	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01562	1.65E-03	na	na	8.27E-05	na	na
		Acrolein	00107-02-8	0.013	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01562	1.99E-04	na	na	9.97E-06	na	na
		Benzene	00071-43-2	0.129	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01562	2.01E-03	na	na	1.01E-04	na	na
		1,3-Butadiene	00106-99-0	0.005	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01562	8.43E-05	na	na	4.21E-06	na	na
		Formaldehyde	00050-00-0	0.163	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01562	2.54E-03	na	na	1.27E-04	na	na
		Naphthalene	00091-20-3	0.012	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01562	1.83E-04	na	na	9.14E-06	na	na
		Toluene	00108-88-3	0.056	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01562	8.82E-04	na	na	4.41E-05	na	na
		CO2E	#N/A	22578.421	lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.01562	3.53E+02	na	na	1.76E+01	na	na
42	1	CT6 Emergency Generator														
		NOX	10102-44-0	611.143	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	7.130	na	na	0.3565	na	na
		CO	00630-08-0	131.691	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	1.536	na	na	0.0768	na	na
		SO2	07446-09-5	0.209	lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.01167	2.44E-03	na	na	1.22E-04	na	na
		PM	na	43.371	lb/1000gal	Assume all PM is PM10	na	na	na	0.01167	0.506	na	na	0.0253	na	na
		PM10	na	43.371	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	0.506	na	na	0.0253	na	na
		PM2.5	na	43.371	lb/1000gal	Equal to PM10	na	na	na	0.01167	0.506	na	na	0.0253	na	na
		VOC	na	49.564	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	0.578	na	na	0.0289	na	na
		Acetaldehyde	00075-07-0	0.106	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.23E-03	na	na	6.17E-05	na	na
		Acrolein	00107-02-8	0.013	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.49E-04	na	na	7.45E-06	na	na
		Benzene	00071-43-2	0.129	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.50E-03	na	na	7.51E-05	na	na
		1,3-Butadiene	00106-99-0	0.005	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	6.30E-05	na	na	3.15E-06	na	na
		Formaldehyde	00050-00-0	0.163	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.90E-03	na	na	9.50E-05	na	na
		Naphthalene	00091-20-3	0.012	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.37E-04	na	na	6.83E-06	na	na
		Toluene	00108-88-3	0.056	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	6.58E-04	na	na	3.29E-05	na	na
		Xylenes	01330-20-7	0.039	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	4.59E-04	na	na	2.29E-05	na	na
		CO2E	#N/A	22578.421	lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.01167	263.415	na	na	13.1707	na	na

KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Hourly (lb/hr) Emissions: Controlled Limited Potential	Hourly (lb/hr) Emissions: Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Annual (tons/yr) Emissions: Controlled Limited Potential	Annual (tons/yr) Emissions: Allowable
43	1	CT7 Emergency Generator														
		NOX	10102-44-0	611.143	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	7.130	na	na	0.3565	na	na
		CO	00630-08-0	131.691	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	1.536	na	na	0.0768	na	na
		SO2	07446-09-5	0.209	lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.01167	2.44E-03	na	na	1.22E-04	na	na
		PM	na	43.371	lb/1000gal	Assume all PM is PM10	na	na	na	0.01167	0.506	na	na	0.0253	na	na
		PM10	na	43.371	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	0.506	na	na	0.0253	na	na
		PM2.5	na	43.371	lb/1000gal	Equal to PM10	na	na	na	0.01167	0.506	na	na	0.0253	na	na
		VOC	na	49.564	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01167	0.578	na	na	0.0289	na	na
		Acetaldehyde	00075-07-0	0.106	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.23E-03	na	na	6.17E-05	na	na
		Acrolein	00107-02-8	0.013	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.49E-04	na	na	7.45E-06	na	na
		Benzene	00071-43-2	0.129	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.50E-03	na	na	7.51E-05	na	na
		1,3-Butadiene	00106-99-0	0.005	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	6.30E-05	na	na	3.15E-06	na	na
		Formaldehyde	00050-00-0	0.163	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.90E-03	na	na	9.50E-05	na	na
		Naphthalene	00091-20-3	0.012	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	1.37E-04	na	na	6.83E-06	na	na
		Toluene	00108-88-3	0.056	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	6.58E-04	na	na	3.29E-05	na	na
		Xylenes	01330-20-7	0.039	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01167	4.59E-04	na	na	2.29E-05	na	na
		CO2E	#N/A	22578.421	lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.01167	263.415	na	na	13.1707	na	na
44	1	CT Area Emergency Fire Pump Engine														
		NOX	10102-44-0	611.143	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01055	6.448	na	na	0.3224	na	na
		CO	00630-08-0	131.691	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01055	1.389	na	na	0.0695	na	na
		SO2	07446-09-5	0.209	lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.01055	2.21E-03	na	na	1.10E-04	na	na
		PM	na	43.371	lb/1000gal	Assume all PM is PM10	na	na	na	0.01055	0.458	na	na	0.0229	na	na
		PM10	na	43.371	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01055	0.458	na	na	0.0229	na	na
		PM2.5	na	43.371	lb/1000gal	Equal to PM10	na	na	na	0.01055	0.458	na	na	0.0229	na	na
		VOC	na	49.564	lb/1000gal	AP42 Table 3.3-1	na	na	na	0.01055	0.523	na	na	0.0261	na	na
		Acetaldehyde	00075-07-0	0.106	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	1.12E-03	na	na	5.58E-05	na	na
		Acrolein	00107-02-8	0.013	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	1.35E-04	na	na	6.73E-06	na	na
		Benzene	00071-43-2	0.129	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	1.36E-03	na	na	6.79E-05	na	na
		1,3-Butadiene	00106-99-0	0.005	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	5.69E-05	na	na	2.85E-06	na	na
		Formaldehyde	00050-00-0	0.163	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	1.72E-03	na	na	8.59E-05	na	na
		Naphthalene	00091-20-3	0.012	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	1.23E-04	na	na	6.17E-06	na	na
		Toluene	00108-88-3	0.056	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	5.96E-04	na	na	2.98E-05	na	na
		Xylenes	01330-20-7	0.039	lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01055	4.15E-04	na	na	2.07E-05	na	na
		CO2E	#N/A	22578.421	lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.01055	238.219	na	na	11.9109	na	na

		Emission Factors				Control Equipment				Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
45	1	Emergency Steam Plant Fire Pump Engine #1													
		NOX	10102-44-0	313.579 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	5.965	na	na	0.2982	na	na
		CO	00630-08-0	113.003 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	2.150	na	na	0.1075	na	na
		SO2	07446-09-5	0.209 lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.01902	3.98E-03	na	na	1.99E-04	na	na
		PM	na	17.385 lb/1000gal	Assume all PM is PM10	na	na	na	0.01902	0.331	na	na	0.0165	na	na
		PM10	na	17.385 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	0.331	na	na	0.0165	na	na
		PM2.5	na	17.385 lb/1000gal	Equal to PM10	na	na	na	0.01902	0.331	na	na	0.0165	na	na
		VOC	na	25.431 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	0.484	na	na	0.0242	na	na
		Acetaldehyde	00075-07-0	0.106 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.01E-03	na	na	1.01E-04	na	na
		Acrolein	00107-02-8	0.013 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.43E-04	na	na	1.21E-05	na	na
		Benzene	00071-43-2	0.129 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.45E-03	na	na	1.22E-04	na	na
		1,3-Butadiene	00106-99-0	0.005 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	1.03E-04	na	na	5.13E-06	na	na
		Formaldehyde	00050-00-0	0.163 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	3.10E-03	na	na	1.55E-04	na	na
		Naphthalene	00091-20-3	0.012 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.23E-04	na	na	1.11E-05	na	na
		Toluene	00108-88-3	0.056 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	1.07E-03	na	na	5.37E-05	na	na
		Xylenes	01330-20-7	0.039 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	7.48E-04	na	na	3.74E-05	na	na
		CO2E	#N/A	22578.421 lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.01902	4.29E+02	na	na	2.15E+01	na	na
46	1	Emergency Steam Plant Fire Pump Engine #2													
		NOX	10102-44-0	313.579 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	5.965	na	na	0.2982	na	na
		CO	00630-08-0	113.003 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	2.150	na	na	0.1075	na	na
		SO2	07446-09-5	0.209 lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.01902	3.98E-03	na	na	1.99E-04	na	na
		PM	na	17.385 lb/1000gal	Assume all PM is PM10	na	na	na	0.01902	0.331	na	na	0.0165	na	na
		PM10	na	17.385 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	0.331	na	na	0.0165	na	na
		PM2.5	na	17.385 lb/1000gal	Equal to PM10	na	na	na	0.01902	0.331	na	na	0.0165	na	na
		VOC	na	25.431 lb/1000gal	Subpart IIII- 60.4205(c)	na	na	na	0.01902	0.484	na	na	0.0242	na	na
		Acetaldehyde	00075-07-0	0.106 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.01E-03	na	na	1.01E-04	na	na
		Acrolein	00107-02-8	0.013 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.43E-04	na	na	1.21E-05	na	na
		Benzene	00071-43-2	0.129 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.45E-03	na	na	1.22E-04	na	na
		1,3-Butadiene	00106-99-0	0.005 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	1.03E-04	na	na	5.13E-06	na	na
		Formaldehyde	00050-00-0	0.163 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	3.10E-03	na	na	1.55E-04	na	na
		Naphthalene	00091-20-3	0.012 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	2.23E-04	na	na	1.11E-05	na	na
		Toluene	00108-88-3	0.056 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	1.07E-03	na	na	5.37E-05	na	na
		Xylenes	01330-20-7	0.039 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.01902	7.48E-04	na	na	3.74E-05	na	na
		CO2E	#N/A	22578.421 lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.01902	4.29E+02	na	na	2.15E+01	na	na

KyEIS ID #	Process ID(s)	Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Hourly (lb/hr) Emissions: Controlled Limited Potential	Hourly (lb/hr) Emissions: Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Annual (tons/yr) Emissions: Controlled Limited Potential	Annual (tons/yr) Emissions: Allowable
47	1	Emergency Quench Water Pump Engine #1													
		NOX	10102-44-0	313.579 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	7.714	na	na	0.3857	na	na
		CO	00630-08-0	217.314 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	5.346	na	na	0.2673	na	na
		SO2	07446-09-5	0.209 lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.02460	0.005	na	na	0.0003	na	na
		PM10	na	11.735 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	0.289	na	na	0.0144	na	na
		PM2.5	na	11.735 lb/1000gal	Equal to PM10	na	na	na	0.02460	0.289	na	na	0.0144	na	na
		VOC	na	25.431 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	0.626	na	na	0.0313	na	na
		CO2E	#N/A	22578.421 lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.02460	555.462	na	na	27.7731	na	na
		Acetaldehyde	00075-07-0	0.106 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.003	na	na	0.0001	na	na
		Acrolein	00107-02-8	0.013 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Benzene	00071-43-2	0.129 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.003	na	na	0.0002	na	na
		1,3-Butadiene	00106-99-0	0.005 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Formaldehyde	00050-00-0	0.163 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.004	na	na	0.0002	na	na
		Naphthalene	00091-20-3	0.012 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Toluene	00108-88-3	0.056 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.001	na	na	0.0001	na	na
		Xylenes	01330-20-7	0.039 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.001	na	na	0.0000	na	na
48	1	Emergency Quench Water Pump Engine #2													
		NOX	10102-44-0	313.579 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	7.714	na	na	0.3857	na	na
		CO	00630-08-0	217.314 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	5.346	na	na	0.2673	na	na
		SO2	07446-09-5	0.209 lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.02460	0.005	na	na	0.0003	na	na
		PM10	na	11.735 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	0.289	na	na	0.0144	na	na
		PM2.5	na	11.735 lb/1000gal	Equal to PM10	na	na	na	0.02460	0.289	na	na	0.0144	na	na
		VOC	na	25.431 lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.02460	0.626	na	na	0.0313	na	na
		CO2E	#N/A	22578.421 lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.02460	555.462	na	na	27.7731	na	na
		Acetaldehyde	00075-07-0	0.106 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.003	na	na	0.0001	na	na
		Acrolein	00107-02-8	0.013 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Benzene	00071-43-2	0.129 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.003	na	na	0.0002	na	na
		1,3-Butadiene	00106-99-0	0.005 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Formaldehyde	00050-00-0	0.163 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.004	na	na	0.0002	na	na
		Naphthalene	00091-20-3	0.012 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Toluene	00108-88-3	0.056 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.001	na	na	0.0001	na	na
		Xylenes	01330-20-7	0.039 lb/1000gal	AP42 Table 3.3-2	na	na	na	0.02460	0.001	na	na	0.0000	na	na

KyEIS ID #	Process ID(s)	Emission Factors					Control Equipment			Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions			Annual (tons/yr) Emissions		
		Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)		Emission Factor Basis	Control Equip. #	Control Device	Control Efficiency		Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
49	1	Emergency Tier II 752 HP Diesel RICE														
		NOX	10102-44-0	270.224	lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.03814	10.308	na	na	0.3857	na	na
		CO	00630-08-0	152.120	lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.03814	5.803	na	na	0.2673	na	na
		SO2	07446-09-5	0.209	lb/1000gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.03814	0.008	na	na	0.0003	na	na
		PM10	na	8.693	lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.03814	0.332	na	na	0.0144	na	na
		PM2.5	na	8.693	lb/1000gal	Equal to PM10	na	na	na	0.03814	0.332	na	na	0.0144	na	na
		VOC	na	7.938	lb/1000gal	Subpart IIII- 60.4205(b)	na	na	na	0.03814	0.303	na	na	0.0313	na	na
		CO2E	#N/A	22578.421	lb/1000gal	40 CFR 98 Subpart C	na	na	na	0.03814	861.252	na	na	27.7731	na	na
		Acetaldehyde	00075-07-0	0.106	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.004	na	na	0.0001	na	na
		Acrolein	00107-02-8	0.013	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.000	na	na	0.0000	na	na
		Benzene	00071-43-2	0.129	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.005	na	na	0.0002	na	na
		1,3-Butadiene	00106-99-0	0.005	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.000	na	na	0.0000	na	na
		Formaldehyde	00050-00-0	0.163	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.006	na	na	0.0002	na	na
		Naphthalene	00091-20-3	0.012	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.000	na	na	0.0000	na	na
		Toluene	00108-88-3	0.056	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.002	na	na	0.0001	na	na
		Xylenes	01330-20-7	0.039	lb/1000gal	AP42 Table 3.4-3	na	na	na	0.03814	0.002	na	na	0.0000	na	na
50	6	New Ash/Gypsum Landfill and Haul Trucks														
		PM	na	na	lb/VMT	AP42 13.2.1/13.2.2	na	Water	70%	4.12	na	3.05	na	na	13.34	na
		PM10	na	na	lb/VMT	AP42 13.2.1/13.2.2	na	Water	70%	4.12	na	0.73	na	na	3.20	na
		PM2.5	na	na	lb/VMT	AP42 13.2.1/13.2.2	na	Water	70%	4.12	na	0.08	na	na	0.36	na

KyEIS ID #	Process ID(s)	Emission Factors: Pollutant	CAS#	Uncontrolled Emission Factor (lb/SCC Units)	Emission Factor Basis	Control Equipment: Control Equip. #	Control Device	Control Efficiency	Hourly Operating Rate (SCC Units/hr)	Hourly (lb/hr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable	Annual (tons/yr) Emissions: Uncontrolled Unlimited Potential	Controlled Limited Potential	Allowable
51	1	Emergency Tier II 1220 HP Diesel RICE													
		NOX	10102-44-0	256.430 lb/1000 gal	Vendor	na	na	na	0.02460	6.309	na	na	0.3154	na	na
		CO	00630-08-0	9.562 lb/1000 gal	Vendor				0.02460	0.235	na	na	0.0118	na	na
		SO2	07446-09-5	0.209 lb/1000 gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.02460	0.005	na	na	0.0003	na	na
		PM10	na	2.173 lb/1000 gal	Vendor				0.02460	0.053	na	na	0.0027	na	na
		PM2.5	na	2.173 lb/1000 gal	Equal to PM10	na	na	na	0.02460	0.053	na	na	0.0027	na	na
		VOC	na	5.650 lb/1000 gal	Vendor				0.02460	0.139	na	na	0.0070	na	na
		CO2E	#N/A	22578.421 lb/1000 gal	40 CFR 98 Subpart C	na	na	na	0.02460	555.462	na	na	27.7731	na	na
		Acetaldehyde	00075-07-0	0.106 lb/1000 gal	AP42 Table 3.4-3				0.02460	0.003	na	na	0.0001	na	na
		Acrolein	00107-02-8	0.013 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Benzene	00071-43-2	0.129 lb/1000 gal	AP42 Table 3.4-3				0.02460	0.003	na	na	0.0002	na	na
		1,3-Butadiene	00106-99-0	0.005 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Formaldehyde	00050-00-0	0.163 lb/1000 gal	AP42 Table 3.4-3				0.02460	0.004	na	na	0.0002	na	na
		Naphthalene	00091-20-3	0.012 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Xylenes	01330-20-7	0.056 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.001	na	na	0.0001	na	na
52	1	Emergency Tier II 1220 HP Diesel RICE													
		NOX	10102-44-0	256.430 lb/1000 gal	Vendor	na	na	na	0.02460	6.309	na	na	0.3154	na	na
		CO	00630-08-0	9.562 lb/1000 gal	Vendor	na	na	na	0.02460	0.235	na	na	0.0118	na	na
		SO2	07446-09-5	0.209 lb/1000 gal	15 ppm; AP42 Tbl 3.4-1	na	na	na	0.02460	0.005	na	na	0.0003	na	na
		PM10	na	2.173 lb/1000 gal	Vendor	na	na	na	0.02460	0.053	na	na	0.0027	na	na
		PM2.5	na	2.173 lb/1000 gal	Equal to PM10	na	na	na	0.02460	0.053	na	na	0.0027	na	na
		VOC	na	5.650 lb/1000 gal	Vendor	na	na	na	0.02460	0.139	na	na	0.0070	na	na
		CO2E	#N/A	22578.421 lb/1000 gal	40 CFR 98 Subpart C	na	na	na	0.02460	555.462	na	na	27.7731	na	na
		Acetaldehyde	00075-07-0	0.106 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.003	na	na	0.0001	na	na
		Acrolein	00107-02-8	0.013 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Benzene	00071-43-2	0.129 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.003	na	na	0.0002	na	na
		1,3-Butadiene	00106-99-0	0.005 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Formaldehyde	00050-00-0	0.163 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.004	na	na	0.0002	na	na
		Naphthalene	00091-20-3	0.012 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.000	na	na	0.0000	na	na
		Toluene	00108-88-3	0.056 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.001	na	na	0.0001	na	na
		Xylenes	01330-20-7	0.039 lb/1000 gal	AP42 Table 3.4-3	na	na	na	0.02460	0.001	na	na	0.0000	na	na

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C01A	Low NOX Burners for Unit 1 Indirect Heat Exchanger	Babcock & Wilcox	XCL-DRB	1993	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
NA °F ______ °C	NA	NA	NA	NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Low NOX burners without over-fire air.

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	NOX	50.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Electrostatic Precipitator

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C01B	ESP for Unit 1 Indirect Heat Exchanger	Buell Division of Envirotech	BA1.2X29K44-2P		

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
296 °F ______ °C	300,317	Unknown	Unknown	Unknown

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of ESP:	Dimensions of ESP (specify units):	Number of stages:	Number of plates per stage:
Pick one: ☑ Dry, negative corona ☐ Wet, negative corona ☐ Wet, positive corona	Collection plate height: 30 ft Length of collection plate in direction of gas flow: 24 ft ESP total width ______ ESP total height ______	8 sections in direction of gas flow; 2 sections across gas flow; 16 total sections/58 gas passages	240 total plates

Particle migration (drift) velocity:	Particle resistivity:	Voltage across plates:
Unknown	Typically 1 x 10^{10} to 1 x 10^{11} ohm-cm	52.5 kV

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
0.3	PM/PM10/PM2.5 Metal HAPs	98.5% - PM10

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C02A	*Low NOX Burners for Unit 2 Indirect Heat Exchanger*	*Combustion Engineering*	*CCOFA System*	*1994*	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
NA °F ______ °C	*NA*	*NA*	*NA*	*NA*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Low NOX coal and air nozzles with close-coupled over-fire air.

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	*NOX*	*35.0%*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Electrostatic Precipitator

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C02B	*ESP for Unit 2 Indirect Heat Exchanger*	*Buell Division of Envirotech*	*BA1.1X47K333*		

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
301 °F ______ °C	*419,573*	*Unknown*	*Unknown*	*Unknown*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of ESP:	Dimensions of ESP (specify units):	Number of stages:	Number of plates per stage:
Pick one: ☑ Dry, negative corona ☐ Wet, negative corona ☐ Wet, positive corona	Collection plate height *30 ft* Length of collection plate in direction of gas flow *27 ft* ESP total width ESP total height	*2 precipitators each with 9 sections in direction of gas flow; 1 section across gas flow; 9 total sections/47 gas passages*	*432 total plates*

Particle migration (drift) velocity:	Particle resistivity:	Voltage across plates:
Unknown	*Typically 1 x 10^{10} to 1 x 10^{11} ohm-cm*	*52.5 kV*

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
0.3	*PM/PM10/PM2.5* *Metal HAPs*	*99.0% - PM10*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C03A	Low NOX Burners for Unit 3 Indirect Heat Exchanger	ABB	LNCFS III	1992	$4 Million

Inlet Gas Stream Data				
Temperature: NA °F ______ °C	Flowrate (scfm at 68°F): NA	Gas density (lb/ft^3): NA	Particle density (lb/ft^3) or Specific Gravity: NA	Average particle diameter (µm): *(or attach a particle size distribution table)* NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Low NOX burners with separated over-fire air.

Equipment Operational Data		
Pressure drop across unit (inches water gauge): NA	Pollutants collected/controlled: NOX	Pollutant removal/destruction efficiency (%): 50.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C03B	Selective Catalytic Reduction for Unit 3 Indirect Heat Exchanger	Riley Power, Inc.	Custom Built	Placed in service 12/20/12	Estimated **$186.5 million**

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
TBD °F ____ °C	TBD	TBD	NA	NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Selective Catalytic Reduction (SCR) System with SO3 Mitigation System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
9 inches	NOX	85.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Scrubber

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C03D	*Wet Limestone Forced-Oxidation Sulfur Dioxide Scrubber (Stack 017)*	*Fluor*	*Custom Built*	*Units 1-3 were all connected by 12/19/10*	*To be determined*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
300 °F ______ °C	*Approx. 1,933,765*	*Unknown*	*Unknown*	*Unknown*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of scrubber:

- ☐ Venturi — Throat type ______
- ☐ Packed bed — Packing type ______ Packing height (inches) ______
- ☑ Spray tower — Number of nozzles *TBD* Nozzle pressure (psig) *TBD*
- ☐ Other (specify) ______

Type of Flow:

- ☐ Concurrent
- ☑ Countercurrent
- ☐ Crossflow

Dimensions of scrubber:

- Length in direction of gas flow *TBD* ft
- Cross-sectional area *TBD* sq.ft
- Venturi throat velocity *TBD* ft/s

Type of mist eliminator:	Dimensions of mist eliminator:	Pressure drop across mist eliminator (in. H_2O):
FRP with high temp flame resistant resin (vertical flow design)	Cross-sectional area *TBD* sq.ft	*Designed to remove 99.5% of droplets > 40 um*
Chemical composition of scrubbing liquid: *Limestone slurry*	Scrubbing liquid flowrate: *2@>90,000* gal/min Fresh liquid makeup rate: *2@2,000* gal/min	Disposal method of scrubber effluent: *Gypsum*

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
6.6	*SO2* *PM* *HCl* *HF*	*98% - SO2*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C03E	*Pulse Jet Fabric Filter with Powered Activated Carbon Injecton System for Unit 3 Indirect Heat Exchanger*	*Clyde Bergemann Power Group*	*Custom Built*	*Startup is anticipated prior to Feb of 2016 (Construction commenced July of 2014)*	*NA*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
~300. °F ______ °C	*1,645,443 acfm per casing*	*NA*	*NA*	*NA*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
FabricFilter	Filtering area: *402,521 ft^2 per casing* Unit total width: Unit total height:	*20 oz/yd^2 Fiberglass, acid resitant with PTFE membrane*

Cleaning method:	Gas cooling method: *na*
☐ Shaker ☐ Pulse Air ☐ Reverse Air ☑ Pulse Jet ☐ Other (specify) ______	☐ Ductwork: Length ______ ft. Diameter ______ inches ☐ Heat Exchanger ☐ Bleed-in Air ______ scfm (@ 68° F) ☐ Water Spray ______ gpm ☐ Other (specify) ______

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
~ 5	*PM/PM10/PM2.5* *Mercury*	*> 99.5% - PM* *> 89% Mercury*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Cyclone					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C13A	Cyclone for Traveling Tripper Units 1 & 2	Fisher-Klosterman	Cyclone System XQ-240-30	1996	50,000

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
70 °F ______ °C	9,005	0.075	2.5	Refer to specifications in 3/30/2006 application

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of cyclone:
Pick one:
- ☐ Single
- ☐ Multiple

Number of multiclone ________

Pick one:
- ☐ High-efficiency
- ☐ Conventional
- ☐ High-throughput

Dimensions of cyclone (specify units): Refer to specifications in 3/30/2006 application

Inlet height	________	Inlet width	________
Body height	________	Body diameter	________
Bottom cone height	________	Dust outlet tube diameter	________
Gas outlet tube diameter	________	Vortex finder height	________

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
Refer to specifications in 3/30/2006 application	PM/PM10/PM2.5	92.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C13B	Fabric Filter for Upper Traveling Tripper Unit 3	U.S. Filter Corp.	Mikro Pulsair #255 Binvent		

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	15,997			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
FabricFilter	Filtering area: 236 ft^2 Unit total width: Unit total height:	

Cleaning method:	Gas cooling method: na
☐ Shaker ☑ Pulse Air ☐ Reverse Air ☐ Pulse Jet ☐ Other (specify) ____________	☐ Ductwork: Length ____ ft. Diameter ____ inches ☐ Heat Exchanger ☐ Bleed-in Air ____________ scfm (@ 68° F) ☐ Water Spray ________ gpm ☐ Other (specify) ____________

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	99.5%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C13C	Fabric Filter for Lower Traveling Tripper Unit 3	U.S. Filter Corp.	Mikro Pulsair #255 Binvent		

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	16,598			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
Fabric Filter	Filtering area: 236 ft^2 Unit total width: Unit total height:	

Cleaning method:	Gas cooling method: na
☐ Shaker ☑ Pulse Air ☐ Reverse Air ☐ Pulse Jet ☐ Other (specify) ______	☐ Ductwork: Length ______ ft. Diameter ______ inches ☐ Heat Exchanger ☐ Bleed-in Air ______ scfm (@ 68° F) ☐ Water Spray ______ gpm ☐ Other (specify) ______

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	99.5%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Scrubber

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C16	Wet Scrubber for Coal Crusher	Engart	Type 33 Dust Extractor	July 2014	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	~17,000			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of scrubber:

- [ ] Venturi — Throat type ______
- [ ] Packed bed — Packing type ______ Packing height (inches) ______
- [x] Spray tower — Number of nozzles ______ Nozzle pressure (psig) ______
- [ ] Other (specify) ______

Type of Flow:

- [ ] Concurrent
- [ ] Countercurrent
- [ ] Crossflow

Dimensions of scrubber:

Length in direction of gas flow ______ ft
Cross-sectional area ______ sq.ft
Venturi throat velocity ______ ft/s

Type of mist eliminator:	Dimensions of mist eliminator: Cross-sectional area ______ sq.ft	Pressure drop across mist eliminator (in. H_2O):
Chemical composition of scrubbing liquid: Water	Scrubbing liquid flowrate: 8 gal/min Fresh liquid makeup rate: ______ gal/min	Disposal method of scrubber effluent: Discharged to coal pile

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	99.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C21	Fabric Filter for Dry Fly Ash Handling	United Conveyor Corp	#O-3205	1/1/1982	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	600			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
Bin Vent Filter	Filtering area: 605 ft^2 Unit total width: Unit total height:	

Cleaning method:
- ☐ Shaker
- ☐ Pulse Air
- ☐ Reverse Air
- ☑ Pulse Jet
- ☐ Other (specify) ______

Gas cooling method: na
- ☐ Ductwork: Length ______ ft. Diameter ______ inches
- ☐ Heat Exchanger
- ☐ Bleed-in Air ______ scfm (@ 68° F)
- ☐ Water Spray ______ gpm
- ☐ Other (specify) ______

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	99.9%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C23	Water Injection for Combustion Turbine 9	ABB Power Generation	GT11N2	11/28/1995	Included in cost of CT

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
851 °F ______ °C	851,731	NA	NA	NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Water Injection System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	NOX	65.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C24	Water Injection for Combustion Turbine 10	ABB Power Generation	GT11N2	12/22/1995	Included in cost of CT

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft³):	Particle density (lb/ft³) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
851 °F ____ °C	851,731	NA	NA	NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Water Injection System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	NOX	65.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C25	*Water Injection for Combustion Turbine 8*	*ABB Power Generation*	*GT11N2*	*3/1/1996*	*Included in cost of CT*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
851 °F ______ °C	*851,731*	*NA*	*NA*	*NA*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Water Injection System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	*NOX*	*65.0%*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C26	*Water Injection for Combustion Turbine 11*	*ABB Power Generation*	*GT11N2*	*5/8/1996*	*Included in cost of CT*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft³):	Particle density (lb/ft³) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
851 °F ______ °C	*851,731*	*NA*	*NA*	*NA*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Water Injection System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	*NOX*	*65.0%*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C27	*Water Injection for Combustion Turbine 6*	*ABB Power Generation*	*GT24AB*	*8/11/1999*	*Included in cost of CT*

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
851 °F ______ °C	*848,878*	*NA*	*NA*	*NA*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Water Injection System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	*NOX*	*65.0%*

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C28	Water Injection for Combustion Turbine 7	ABB Power Generation	GT24AB	8/8/1999	Included in cost of CT

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
851 °F ____ °C	848,878	NA	NA	NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Water Injection System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	NOX	65.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Other Type of Control Equipment

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C29	Water Injection for Combustion Turbine 5	ABB Power Generation	11N2	5/8/1996	Included in cost of CT

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (µm): *(or attach a particle size distribution table)*
851 °F ______ °C	735,288	NA	NA	NA

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of control equipment (give descriptions and a sketch with dimensions):

Water Injection System

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
NA	NOX	65.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C30	Fabric Filter for Limestone Truck Dump #1	Dantherm MJC	MJB 105/XL/10-11	2008	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	8,828			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
Vent Filter	Filtering area: 1,054 ft^2 Unit total width: Unit total height:	Glazed Polyester Needlefelt

Cleaning method:	Gas cooling method: na
☐ Shaker ☐ Pulse Air ☑ Reverse Air ☐ Pulse Jet ☐ Other (specify) ______	☐ Ductwork: Length ______ ft. Diameter ______ inches ☐ Heat Exchanger ☐ Bleed-in Air ______ scfm (@ 68° F) ☐ Water Spray ______ gpm ☐ Other (specify) ______

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	98.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C31	Fabric Filter for Limestone Truck Dump #2	Dantherm MJC	MJB 105/XL/10-11	2008	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft³):	Particle density (lb/ft³) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	8,828			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
Vent Filter	Filtering area: 1,054 ft² Unit total width: Unit total height:	Glazed Polyester Needlefelt

Cleaning method:	Gas cooling method: na
☐ Shaker ☐ Pulse Air ☑ Reverse Air ☐ Pulse Jet ☐ Other (specify) ______	☐ Ductwork: Length ______ ft. Diameter ______ inches ☐ Heat Exchanger ☐ Bleed-in Air ______ scfm (@ 68° F) ☐ Water Spray ______ gpm ☐ Other (specify) ______

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	98.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C32	Fabric Filter for Limestone Stacker Tube	Donaldson Dalamatic Collector	DLM V30/15K5FAD	2008	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	1,923			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
Vent Filter	Filtering area: 323 ft^2 Unit total width: Unit total height:	10 oz Duralife Scrim Supported Polyester

Cleaning method:	Gas cooling method: na
☐ Shaker ☐ Pulse Air ☐ Reverse Air ☑ Pulse Jet ☐ Other (specify) ________	☐ Ductwork: Length ______ ft. Diameter ______ inches ☐ Heat Exchanger ☐ Bleed-in Air ________ scfm (@ 68° F) ☐ Water Spray ______ gpm ☐ Other (specify) ________

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	98.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter					
KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C33	Fabric Filter for Limestone Reclaim Conveyor #1	Greenheck	MSX-118-H32	2008	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft³):	Particle density (lb/ft³) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	1,923			

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit:	Dimensions of filter unit (specify units):	Filtering material:
Vent Filter	Filtering area: 323 ft^2 Unit total width: Unit total height:	10 oz Duralife Scrim Supported Polyester

Cleaning method:	Gas cooling method: na
☐ Shaker ☐ Pulse Air ☐ Reverse Air ☑ Pulse Jet ☐ Other (specify) ______	☐ Ductwork: Length ___ ft. Diameter ___ inches ☐ Heat Exchanger ☐ Bleed-in Air ______ scfm (@ 68° F) ☐ Water Spray ______ gpm ☐ Other (specify) ______

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	98.0%

DEP7007N
(continued)

SECTION III. Control Equipment Information for Filter

KyEIS Control ID #	Control Equipment Description	Manufacturer	Model Name and Number	Date Installed	Cost
C34	*Fabric Filter for Limestone Reclaim Conveyor #2*	*Greenheck*	*MSX-118-H32*	*2008*	

Inlet Gas Stream Data

Temperature:	Flowrate (scfm at 68°F):	Gas density (lb/ft^3):	Particle density (lb/ft^3) or Specific Gravity:	Average particle diameter (μm): *(or attach a particle size distribution table)*
Amb. °F ______ °C	*1,923*	*Unknown*	*Unknown*	*Unknown*

Equipment Physical Data

The control equipment manufacturer's equipment specifications and recommended operating procedures may be submitted in place of this information.

Type of filter unit: *Vent Filter*

Dimensions of filter unit (specify units):

Filtering area: *323 ft^2*

Unit total width:

Unit total height:

Filtering material: *10 oz Duralife Scrim Supported Polyester*

Cleaning method:
- ☐ Shaker
- ☐ Pulse Air
- ☐ Reverse Air
- ☑ Pulse Jet
- ☐ Other (specify) ____________

Gas cooling method: *na*
- ☐ Ductwork: Length ____ ft. Diameter ____ inches
- ☐ Heat Exchanger
- ☐ Bleed-in Air ____________ scfm (@ 68° F)
- ☐ Water Spray ________ gpm
- ☐ Other (specify) ____________

Equipment Operational Data

Pressure drop across unit (inches water gauge):	Pollutants collected/controlled:	Pollutant removal/destruction efficiency (%):
	PM/PM10/PM2.5	*98.0%*

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

imber
DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
01	Unit 1 Indirect Heat Exchanger	SO2	401 KAR 61:015 Section 5(1)	SO2 emissions limited to 5.15 lb/MMBtu (24-hour average)	SO2 CEMS
		PM	401 KAR 61:015 Section 4(1) & (4)	PM emissions limited to 0.254 lb/MMBtu (3-hour average)	Periodic Performance Test
		Opacity	401 KAR 61:015 Section 4(3)	Emissions shall not exceed 40% opacity (6-minute average) except that a maximum of 60% opacity is allowed for periods or aggregate of periods of not more than 6 minutes in any 60 minutes during building a new fire for the period require to bring the boiler up to operating conditions	Method 9 every 14 operating days (Common Stack)
		HAPs	40 CFR 63.9984(b)	Comply with 40 CFR 63, Subpart UUUUU, no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.
		HAPs	40 CFR 63.9984(c)	Meet the notification requirements in 40 CFR 63.10030 according to the schedule in 40 CFR 63.10030 and in 40 CFR 63, Subpart A.	Submittal of required notification reports.
		HAPs	40 CFR 63.9984(f)	Conduct performance tests and other activities to demonstrate compliance no later than 180 days after the applicable date in paragraph (b) or (c) of 40 CFR 63.9984.	Completion of required performance testing.
		HAPs	40 CFR 63, Subpart UUUUU	Comply with all applicable provisions of 40 CFR 63.9991 no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.
		HAPs	40 CFR 63, Subpart UUUUU	Demonstrate continuous compliance according to 40 CFR 63.10000 through 40 CFR 63.10023, no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
02	Unit 2 Indirect Heat Exchanger	SO2	401 KAR 61:015 Section 5(1)	SO2 emissions limited to 5.15 lb/MMBtu (24-hour average)	SO2 CEMS
		PM	401 KAR 61:015 Section 4(1) & (4) and Self-Imposed Limit from Historical Air Modeling	PM emissions limited to 0.162 lb/MMBtu (3-hour average)	Periodic Performance Test
		Opacity	401 KAR 61:015 Section 4(3)	Emissions shall not exceed 40% opacity (6-minute average) except that a maximum of 60% opacity is allowed for periods or aggregate of periods of not more than 6 minutes in any 60 minutes.	Method 9 every 14 operating days (Common Stack); COM if bypass stack is in operation
		HAPs	40 CFR 63.9984(b)	Comply with 40 CFR 63, Subpart UUUUU, no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.
		HAPs	40 CFR 63.9984(c)	Meet the notification requirements in 40 CFR 63.10030 according to the schedule in 40 CFR 63.10030 and in 40 CFR 63, Subpart A.	Submittal of required notification reports.
		HAPs	40 CFR 63.9984(f)	Conduct performance tests and other activities to demonstrate compliance no later than 180 days after the applicable date in paragraph (b) or (c) of 40 CFR 63.9984.	Completion of required performance testing.
		HAPs	40 CFR 63, Subpart UUUUU	Comply with all applicable provisions of 40 CFR 63.9991 no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.
		HAPs	40 CFR 63, Subpart UUUUU	Demonstrate continuous compliance according to 40 CFR 63.10000 through 40 CFR 63.10023, no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

lmber
DEP7007V
Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
03	Unit 3 Indirect Heat Exchanger	PM	401 KAR 61:015 Section 4(1) and (4); 2009 Consent Decree	~~- PM emissions limited to 0.254 lb/MMBtu (3-hour average) until December 31, 2010.~~ - ~~By December 31, 2010,~~ PJFF for Unit 3 to achieve a PM limit of not greater than 0.030 lb/MMBtu (3-hr average) - *Please note that the switch from the ESP to PJFF was part of the permit mod from 2/15/13. DOJ and EPA determined that this was a non-material changed to the consent decree.*	Annual performance test and PM CEMS
		SO2	401 KAR 61:015 Section 5(1) and 2009 Consent Decree	- SO2 emissions limited to 5.15 lb/MMBtu (24-hour average) ~~- By December 31, 2010,~~ Continuously operate FGD to achieve SO2 limit of not greater than 0.100 lb/MMBtu (30-day average) or SO2 removal efficiency of at least 97% (30-day average) ~~- Annual Unit 3 limit of 31,998 tpy for 2009 & 2010~~ - Annual Unit 3 limit of 2,300 tpy ~~beginning with 2011 and on a~~ per calendar year ~~basis thereafter~~	SO2 CEMS and reporting
		NOx	2009 Consent Decree	- ~~By December 31, 2012,~~ Continuously operate SCR to achieve NOx limit of not greater than 0.070 lb/MMBtu (30-day average) or if the dispatch of Unit 3 requires operation with a flue gas temperature that does not allow use of the SCR, a limit of 0.080 lb/MMBtu (30-day average) applies ~~- Annual Unit 3 limit of 4,072 tpy for 2009 through 2012~~	NOx CEMS and reporting SCR operational data

Imber

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
		Opacity	401 KAR 61:015 Section 4(3)	Emissions shall not exceed 40% opacity (6-minute average) except that a maximum of 60% opacity is allowed for periods or aggregate of periods of not more than 6 minutes in any 60 minutes during building a new fire, cleaning the firebox, or blowing soot.	Method 9 every 14 operating days
		HAPs	40 CFR 63.9984(b)	Comply with 40 CFR 63, Subpart UUUUU, no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.
		HAPs	40 CFR 63.9984(c)	Meet the notification requirements in 40 CFR 63.10030 according to the schedule in 40 CFR 63.10030 and in 40 CFR 63, Subpart A.	Submittal of required notification reports.
		HAPs	40 CFR 63.9984(f)	Conduct performance tests and other activities to demonstrate compliance no later than 180 days after the applicable date in paragraph (b) or (c) of 40 CFR 63.9984.	Completion of required performance testing.
		HAPs	40 CFR 63, Subpart UUUUU	Comply with all applicable provisions of 40 CFR 63.9991 no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.
		HAPs	40 CFR 63, Subpart UUUUU	Demonstrate continuous compliance according to 40 CFR 63.10000 through 40 CFR 63.10023, no later than April 16, 2015.	Testing, monitoring, and recordkeeping as prescribed in rule.
		SAM	2009 Consent Decree 401 KAR 51:017	473.1 tons for Units 1-3	Monthly cals/log with 12 month rolling SAM emissions
		All	2009 Consent Decree	Hourly heat input rate of Unit 3 may not exceed 5,300 MMBtu/hr.	Calculation using hourly mass of coal burned and weekly composite fuel sampling analysis data.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

Imber

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.[(1)**]	Emission Unit Description[(2)]	Contaminant[(3)]	Origin of Requirement or Standard[(4)]	Applicable Requirement, Standard, Restriction, Limitation, or Exemption[(5)*]	Method of Determining Compliance with the Emission and Operating Requirement(s)[(6)]
07	Coal Handling Operations 07	PM	401 KAR 63:010	No visible emissions shall cross the property line.	Monitoring and Recordkeeping
09	Coal Handling Operations 09	Opacity	NSPS Subpart Y	20% opacity per 60.254(a).	Quarterly Method 22 visible emissions observations followed by a Method 9 opacity performance test if necessary.
13	Coal Handling Operations 13	PM	401 KAR 61:020 Section 3(2)	PM emissions limited to value calculated according to process weight rule in 401 KAR 61:020.	Recordkeeping -Each unit is considered in compliance when the associated control equipment (cyclone and fabric filters) is in operation
		Opacity	401 KAR 61:020 Section 3(1)(a)	Visible emissions limited to 40 percent opacity (6-minute average).	Monitoring (monthly rate and hrs of operation)
16	Coal Crushing	PM	401 KAR 61:020 Section 3(2)	PM emissions limited to value calculated according to process weight rule in 401 KAR 61:020.	Recordkeeping -Each unit is considered in compliance when the associated control equipment(wet scrubber) is in operation
		Opacity	401 KAR 61:020 Section 3(1)(a)	Visible emissions limited to 40 percent opacity (6-minute average).	Recordkeeping -Each unit is considered in compliance when the associated control equipment is in operation
21	Dry Fly Ash Handling	PM	401 KAR 59:010 Section 3(2)	PM emissions limited to value calculated according to process weight rule in Appendix A to 401 KAR 59:010.	Monitoring - (CAM plan/monthly inspections of controls and daily QV's when in operation)
		Opacity	401 KAR 59:010 Section 3(1)(a)	Visible emissions limited to 20 percent opacity (6-minute average).	Monitoring - (CAM plan/monthly inspections of controls and daily QV's when in operation)

Imber

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
023 024 025 026 029	Combustion Turbine Unit 9 Combustion Turbine Unit 10 Combustion Turbine Unit 8 Combustion Turbine Unit 11 Combustion Turbine Unit 5	All	401 KAR 51:017	The rated capacity at ISO standard conditions shall not exceed 1,368 MMBtu/hr for each turbine.	Monthly recordkeeping
		All	401 KAR 51:017	Maximum annual hours of operation shall not exceed 2,500 hours/year for each turbine when combusting fuel oil (please see Appendix G).	Monthly recordkeeping
		NOx	40 CFR 60.332(a) and 401 KAR 51:017	NOx emissions from each turbine shall not exceed 65 ppm by volume at 15% oxygen on a dry basis when burning number two fuel oil NA for Unit 5)	Continuous oxygen monitoring
			40 CFR 60.332(a) and 401 KAR 51:017	NOx emissions from each turbine shall not exceed 42 ppm by volume at 15% oxygen on a dry basis when burning natural gas, except for Unit 5, which is limited to 25 ppm by volume.	Continuous oxygen monitoring
		Fuel Sulfur	40 CFR 60.333(b) and 401 KAR 51:017	Weight percent sulfur in fuel oil shall not exceed 0.30% when operating 6 or less turbines and 0.26% when operating 7 turbines.	Fuel use monitoring and fuel sulfur analysis.
		SO2	40 CFR 60.333 and 401 KAR 51:017	SO2 emissions limited to 444 lb/hr per turbine.	Fuel use monitoring and fuel sulfur analysis.
		CO	401 KAR 51:017	CO emissions limited to 75 lb/hr and 93.8 tpy per turbine.	Fuel use monitoring and emission factors.
		PM	401 KAR 51:017	PM emissions limited to 67 lb/hr and 83.8 tpy per turbine.	Fuel use monitoring and emission factors.
		VOC	401 KAR 51:017	VOC emissions limited to 20.4 lb/hr and 25.5 tpy per turbine.	Fuel use monitoring and emission factors.
		Beryllium	401 KAR 51:017	Beryllium emissions limited to 3.37E-03 lb/hr and 4.21E-03 tpy per turbine.	Fuel use monitoring and emission factors.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.[(1)**]	Emission Unit Description[(2)]	Contaminant[(3)]	Origin of Requirement or Standard[(4)]	Applicable Requirement, Standard, Restriction, Limitation, or Exemption[(5)*]	Method of Determining Compliance with the Emission and Operating Requirement(s)[(6)]
027 028	Combustion Turbine Unit 6 Combustion Turbine Unit 7	Heat Input	401 KAR 51:017	The rated capacity at ISO standard conditions shall not exceed 1,678 MMBtu/hr for each turbine.	Monthly recordkeeping
		Hours of Operation	401 KAR 51:017	Maximum annual hours of operation shall not exceed 2,500 hours/year for each turbine when combusting fuel oil (please see Appendix G).	Monthly recordkeeping
		NOx	40 CFR 60.332 and 401 KAR 51:017	NOx emissions from each turbine shall not exceed 42 ppm by volume at 15% oxygen on a dry basis when burning number two fuel oil.	Continuous oxygen monitoring
			40 CFR 60.332 and 401 KAR 51:017	NOx emissions from each turbine shall not exceed 25 ppm by volume at 15% oxygen on a dry basis when burning natural gas.	Continuous oxygen monitoring
		Fuel Sulfur	40 CFR 60.333 and 401 KAR 51:017	Weight percent sulfur in fuel oil shall not exceed 0.26% when operating 6 or less turbines and 0.23% when operating 7 turbines.	Fuel use monitoring and fuel sulfur analysis.
		SO2	40 CFR 60.333 and 401 KAR 51:017	SO2 emissions limited to 666 lb/hr per turbine.	Fuel use monitoring and fuel sulfur analysis.
		CO	401 KAR 51:017	CO emissions limited to 112.5 lb/hr and 140.63 tpy per turbine.	Fuel use monitoring and emission factors.
		PM	401 KAR 51:017	PM emissions limited to 100.5 lb/hr and 125.63 tpy per turbine.	Fuel use monitoring and emission factors.
		VOC	401 KAR 51:017	VOC emissions limited to 30.6 lb/hr and 38.25 tpy per turbine.	Fuel use monitoring and emission factors.
		Beryllium	401 KAR 51:017	Beryllium emissions limited to 5.057E-03 lb/hr and 6.35E-03 tpy per turbine.	Fuel use monitoring and emission factors.
030 031	Limestone Truck Dump Station #1 Limestone Truck Dump Station #2	PM	40 CFR 60.672(d)	Exempt from emission limits	NA - Exempt
		Opacity	40 CFR 60.672(d)	Exempt from emission limits	NA - Exempt

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

Imber

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
032 033 034	Limestone Stacking Tube Limestone Reclaim Conveyor #1 Limestone Reclaim Conveyor #2	PM	NSPS Subpart OOO	PM emissions from stacks are limited to 0.022 gr/dscf per 60.672(a).	Initial performance test has been performed. Quarterly Method 22's or use of a bag leak detection system.
		Opacity	NSPS Subpart OOO	Opacity from stacks is limited to 7% per 60.672(a).	Initial performance test has been performed. Quarterly Method 22's or use of a bag leak detection system.
35	Road Fugitives from Truck Traffic on Unpaved and Paved Roads	PM	401 KAR 63:010	No visible emissions shall cross the property line.	Proper maintenance of roads.
036 037 038	Unit 1 Cooling Tower with Drift Eliminators Unit 2 Cooling Tower with Drift Eliminators Unit 3 Cooling Tower with Drift Eliminators	PM	401 KAR 63:010	No visible emissions shall cross the property line.	Proper design and maintenance of cooling towers and mist eliminators. Monitoring and Recordkeeping
039	Dix Dam Crest Gate Emergency Generator - 40 HP (Existing SI Emergency < 500 HP)	NA/Work Practices	40 CFR 63, Subpart ZZZZ	Work Practices	A non-resettable hour meter shall be installed on the emergency generator. Change oil every 500 hrs of operation with min of annual or testing; Inspect spark plugs every 1000 hor or min annually; Inspect hoses and belts every 500 or annually; Minimize idle time

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.[(1)**]	Emission Unit Description[(2)]	Contaminant[(3)]	Origin of Requirement or Standard[(4)]	Applicable Requirement, Standard, Restriction, Limitation, or Exemption[(5)*]	Method of Determining Compliance with the Emission and Operating Requirement(s)[(6)]
040 041 042 043 044	Dix Dam Station Emergency Generator CT5 Emergency Generator CT6 Emergency Generator CT6 Emergency Generator CT7 Emergency Generator (Existing CI Emergency RICE < 500 HP)	NA	40 CFR 63.6595(a)(1)	Comply with the applicable 40 CFR 63, Subpart ZZZZ limits	Recordkeeping as prescribed in rule.
		NA	40 CFR 63.6602 40 CFR 63, Subpart ZZZZ, Table 2c	Comply with the following limitations: -Change oil and filter every 500 hours or annually (whichever is first); -Inspect air cleaner every 1,000 hours or annually, (whichever is first); -Inspect all hoses and belts every 500 hours or annually (whichever is first), replace as necessary; -If unable to perform work practice requirement on schedule because of operations during an emergency, perform as soon as practicable and report as required	Operate according to manufacturer's instructions or develop and follow a maintenance plan consistent with good air pollution control practice for minimizing emissions.
		NA	40 CFR 63.6605(a)	Compliance with the applicable requirements in 40 CFR 63, Subpart ZZZZ (emission limits, operating limits, other requirement as they apply)	Recordkeeping as prescribed in rule.
		NA	40 CFR 63.6604(b)	If engine operates or is contractually obligated to be available for more than 15 hours per year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), use diesel fuel that meets the requirements in 40 CFR 80.510(b). Existing diesel fuel (prior to January 1, 2015) may be used until depleted.	Maintain fuel and hourly use records

Imber

DEP7007V

Applicable Requirements & Compliance

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
		NA	40 CFR 63.6605(e)	Operate and maintain the engine and any after-treatment control devices according to the manufacturer's instructions or develop a maintenance plan consistent with good air pollution control practice for minimizing emissions.	Operate according to manufacturer's instructions or develop and follow a maintenance plan consistent with good air pollution control practice for minimizing emissions.
		NA	40 CFR 63.6640(f)	To be considered an emergency engine, operate the engine according to the requirements for emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for fifty (50) hours per year, as described in 40 CFR 63.6640(f)(1) through (3). There is no time limit on the use of emergency stationary RICE in emergency situations, when those emergency situations meet the requirements of 40 CFR 63.6640(f).	Maintain records of hours and engine use.
		NA	40 CFR 63.6625(h)	Minimize startup idle and startup time, not to exceed 30 minutes, after 30 minutes standards in Subpart ZZZZ, Table 2c apply.	Maintain records of hours and engine use.

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
		NA	40 CFR 63.6604(i)	If engine is subject to work practice, option to utilize an oil analysis	Maintain records, parameters analyzed, results, maintenance plan
045 046 047 048	Emergency Steam Plant Fire Pump Engine #1 Emergency Steam Plant Fire Pump Engine #2 Emergency Quench Water Pump Engine #1 Emergency Quench Water Pump Engine #2 (New CI Emergency RICE < 500 HP)	NA	40 CFR 60.4209(a)	Must have a non-resettable hour meter	Records/hour of operation
		NA	40 CFR 60.4207(a) & (b)	Use ULSD, except that existing diesel fuel purchased prior to 10/1/10 may be used until depleted	Fuel supplier certification

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
		NA	40 CFR 60.4207(f)	Operated as required per 60.4207(f)	Records of operation and purpose
		NMHC + Nox, CO, PM	40 CFR 60.4205(c)	Comply with the emission limits noted in 40 CFR 60.4205(c) or purchase of a certified engine which meets the emission stds. Must operate engine and control device, if applicable, per the mfg written instructions or operating procedures.	Operate according to manufacturer's instructions or develop and follow a maintenance plan consistent with good air pollution control practice for minimizing emissions. Records of certifed engine
049	Emergency 752 HP Engine (New CI Emergency RICE > 500 HP)	NA	40 CFR 60.4207(a) & (b)	Use ULSD, except that existing diesel fuel purchased prior to 10/1/10 may be used until depleted	Fuel supplier certification
		NA	40 CFR 60.4209(a)	Must have a non-resettable hour meter	Records/hour of operation
		NA	40 CFR 60.4211(f)	Operated as required per 60.4207(f)	Records of operation and purpose
		NA	40 CFR 60.4205(c)	Comply with the emission limits noted in 40 CFR 60.4205(b) or purchase of a certified engine which meets the emission stds. Must operate engine and control device, if applicable, per the mfg written instructions or operating procedures.	Operate according to manufacturer's instructions or develop and follow a maintenance plan consistent with good air pollution control practice for minimizing emissions.

Imber

DEP7007V

Applicable Requirements & Compliance

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
050	New Ash/Gypsum Landfill and Haul Trucks	Fugitive Emissions	401 KAR 63:010	Discharge of visible fugitive dust emissions beyond the property line is prohibited	Monitoring and Recordkeeping
			401 KAR 63:010, Section 3(1)	No person shall cause, suffer, or allow any material to be handled, processed, transported, or stored; a building or its appurtenances to be constructed, altered, repaired, or demolished, or a road to be used without taking reasonable precaution to prevent particulate matter from becoming airborne.	Monitoring and Recordkeeping
			401 KAR 63:010, Section 4	At all times when in motion, open bodied trucks, operating outside company property, transporting materials likely to become airborne shall be covered. No one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway.	Posting a 15 mile per hour sign for each road way to enforced speed limit
"051 052	Emergency Tier II 1220 HP Diesel RICE Emergency Tier II 1220 HP Diesel RICE (New CI Emergency RICE > 500 HP)	NA	40 CFR 60.4207(a) & (b)	Use ULSD, except that existing diesel fuel purchased prior to 10/1/10 may be used until depleted	Fuel supplier certification
		NA	40 CFR 60.4209(a)	Must have a non-resettable hour meter	Records/hour of operation
		NA	40 CFR 60.4211(f)	Operated as required per 60.4207(f)	Records of operation and purpose

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007V

Applicable Requirements & Compliance

APPLICANT NAME: EW Brown

SECTION I. EMISSION AND OPERATING STANDARD(S) AND LIMITATION(S)

KYEIS No.(1)**	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Applicable Requirement, Standard, Restriction, Limitation, or Exemption(5)*	Method of Determining Compliance with the Emission and Operating Requirement(s)(6)
		NA	40 CFR 60.4205(c)	Comply with the emission limits noted in 40 CFR 60.4205(b) or purchase of a certified engine which meets the emission stds. Must operate engine and control device, if applicable, per the mfg written instructions or operating procedures.	Operate according to manufacturer's instructions or develop and follow a maintenance plan consistent with good air pollution control practice for minimizing emissions.

* See text of cited rule or the 2009 Consent Decree for a complete description of the applicable requirement.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION II. MONITORING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Monitored(7)	Description of Monitoring(8)*
01	Unit 1 Indirect Heat Exchanger	SO2	401 KAR 52:020 Section 10 and 401 KAR 61:005	SO2 and O2 or CO2	Install, calibrate, maintain, and operate a CEMS for measuring SO2 emissions and either O2 or CO2 emissions.
			401 KAR 61:015 Section 6(1)	Sulfur Content of Fuel	Determine the sulfur content of solid fuels per methods specified by Division.
		PM	40 CFR 64.6(c)	PM	PM CEMs from FGD stack
			401 KAR 61:015 Section 6(3)	Process Information	Measure the rate of each fuel burned daily, the heating value and ash content of fuels at least once per week, and the average electrical output daily, and the minimum and maximum hourly generation rate daily. Date, time and duration of each startup and shutdown event
		Opacity	401 KAR 63:015	Opacity	Method 9 every 14 operating days (FGD stack)
		HAPS	40 CFR 63, Subpart UUUUU	NA	The permittee shall comply with all applicable continuous monitoring requirements of 40 CFR 63.10010, 40 CFR 63.10020, and 40 CFR 63.10021, no later than April 16, 2015.
02	Unit 2 Indirect Heat Exchanger	SO2	401 KAR 52:020 Section 10 and 401 KAR 61:005	SO2 and O2 or CO2	Install, calibrate, maintain, and operate a CEMS for measuring SO2 emissions and either O2 or CO2 emissions.
			401 KAR 61:015 Section 6(1)	Sulfur Content of Fuel	Determine the sulfur content of solid fuels per methods specified by Division.
		PM	401 KAR 52:020 Section 10 and 401 KAR 61:005	Opacity	Install, calibrate, maintain, and operate a COMS for measuring opacity (used when bypass stack is in operation). Method 9 every 14 operating days (FGD stack)
			401 KAR 61:015 Section 6(3)	Process Information	Measure the rate of each fuel burned daily, the heating value and ash content of fuels at least once per week, and the average electrical output daily, and the minimum and maximum hourly generation rate daily. Date, time and duration of each startup and shutdown event
			40 CFR 64.6(c)	PM	PM CEMs from FGD stack
		Opacity	401 KAR 63:015	Opacity	If any 6-minute average opacity value exceeds the opacity standard and any visible emissions are seen, opacity must be determined using Method 9 or by accepting the concurrent reading from the COMS.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION II. MONITORING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Monitored(7)	Description of Monitoring(8)*
03	Unit 3 Indirect Heat Exchanger	SO2	401 KAR 52:020 Section 10 and 401 KAR 61:005	SO2 and O2 or CO2	Install, calibrate, maintain, and operate a CEMS for measuring SO2 emissions and either O2 or CO2 emissions.
			401 KAR 61:015 Section 6(1)	Sulfur Content of Fuel	Determine the sulfur content of solid fuels per methods specified by Division.
		PM	401 KAR 52:020 Section 10 and 401 KAR 61:005	Opacity	Method 9 every 14 operating days (FGD stack)
			401 KAR 61:015 Section 6(3)	Process Information	Measure the rate of each fuel burned daily, the heating value and ash content of fuels at least once per week, and the average electrical output daily, and the minimum and maximum hourly generation rate daily. Date, time and duration of each startup and shutdown event
			40 CFR 64.6(c)	PM	PM CEMs from FGD stack
			2009 Consent Decree	PM and CO2	Install, calibrate, maintain, and operate a CEMS for measuring PM and CO2.
		NOx	2009 Consent Decree, 401 KAR 61:005, and 40 CFR 64	NOx	Install, calibrate, maintain, and operate a CEMS for measuring NOx in accordance with the reference methods in 40 CFR 75 except that NOx emissions data need not be bias-adjusted.
		Opacity	401 KAR 63:015	Opacity	Install, calibrate, maintain, and operate a COMS for measuring opacity. If any 6-minute average opacity value exceeds the opacity standard and any visible emissions are seen, opacity must be determined using Method 9 or by accepting the concurrent reading from the COMS.
		SAM	40 CFR 64.6(c)	SO2 Sorbent Injection System SCR PJFF	SO2 Sorbent Injection System and controls - Unit load, SCR temp, injection rate/hourly rate for each operating day, FGD SO2 outlet, PJFF parameters SAM trigger levels
		All	2009 Consent Decree	Coal Burned and Composite Fuel Sampling	Monitor hourly mass of coal burned and take weekly composite fuel sample for analysis.
		HAPS	40 CFR 63, Subpart UUUUU	NA	The permittee shall comply with all applicable continuous monitoring requirements of 40 CFR 63.10010, 40 CFR 63.10020, and 40 CFR 63.10021, no later than April 16, 2015.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION II. MONITORING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Monitored(7)	Description of Monitoring(8)*
13	Coal Handling Operations 13	PM	401 KAR 61:020	Operating Rate and Hours of Operation	Monitor the operating rate and hours of operation on a daily basis.
		Opacity	401 KAR 61:020 and 40 CFR 64	Opacity	QV weekly, Method 9 if triggered.
16	Coal Crushing	PM	401 KAR 61:020	Operating Rate and Hours of Operation	Monitor the operating rate and hours of operation on a daily basis.
		Opacity	401 KAR 61:020 and 40 CFR 64	Opacity	QV weekly, Method 9 if triggered.
21	Dry Fly Ash Handling		401 KAR 59:010	Tons and Hours of Operation	Monitor the tons and hours of operation monthly
			40 CFR 64.6(c)	CAM	CAM plan (daily QV,inspection of controls)
023 024 025 026 029	Combustion Turbine Unit 9 Combustion Turbine Unit 10 Combustion Turbine Unit 8 Combustion Turbine Unit 11 Combustion Turbine Unit 5	NOx	40 CFR 60.332 and 401 KAR 51:017	Oxygen	The Division approved alternate system for measuring oxygen levels shall be installed, calibrated, maintained, and operated in accordance with manufacturer's instructions and 40 CFR 75.
		All	401 KAR 51:017 and 401 KAR 52:020 Section 10	Fuel Consumption, Hours of Operation, and Power Output	Monitor the fuel consumption, hours of operation, and power output (in MW) daily for each emission unit.
		SO2	401 KAR 52:060	Fuel Sulfur Content	Monitor the sulfur content of the fuel being fired in each turbine as required in 40 CFR 75 Appendix D.
027 028	Combustion Turbine Unit 6 Combustion Turbine Unit 7	NOx	40 CFR 60.332 and 401 KAR 51:017	Oxygen	The Division approved alternate system for measuring oxygen levels shall be installed, calibrated, maintained, and operated in accordance with manufacturer's instructions and 40 CFR 75.
		All	401 KAR 51:017 and 401 KAR 52:020 Section 10	Fuel Consumption, Hours of Operation, and Power Output	Monitor the fuel consumption, hours of operation, and power output (in MW) daily for each emission unit.
		SO2	401 KAR 52:060	Fuel Sulfur Content	Monitor the sulfur content of the fuel being fired in each turbine as required in 40 CFR 75 Appendix D.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION II. MONITORING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Monitored(7)	Description of Monitoring(8)*
030 031	Limestone Truck Dump Station #1 Limestone Truck Dump Station #2	PM	401 KAR 59:020, Section 10	Material processed	Monitor the monthly material processed and hours of operation.
		Opacity	401 KAR 59:010 and 40 CFR 64	Opacity	Quarterly Method 22 visible emissions observations followed by a Method 9 opacity performance test if triggered.
032 033 034	Limestone Stacking Tube Limestone Reclaim Conveyor #1 Limestone Reclaim Conveyor #2	PM	401 KAR 59:020, Section 10	Material processed	Monitor the monthly material processed and hours of operation.
		Opacity	401 KAR 59:010, NSPS Subpart OOO, and 40 CFR 64	Opacity	Quarterly Method 22 visible emissions observations followed by a Method 9 opacity performance test if triggered.
35	Road Fugitives from Truck Traffic on Unpaved and Paved Roads	PM	401 KAR 52:020 (Section 10)	fugitives	VMT monthly and inspections (water usage , enclosures)
036 037 038	Unit 1 Cooling Tower with Drift Eliminators Unit 2 Cooling Tower with Drift Eliminators Unit 3 Cooling Tower with Drift Eliminators	PM	401 KAR 52:020	fugitives	Inspections/use of drift eliminators
039	Dix Dam Crest Gate Emergency Generator - 40 HP (Existing SI Emergency < 500 HP)	NA/Work Practices	40 CFR 63.6625(f) and (i)	Hours Change oil or testing	A non-resettable hour meter shall be installed on the emergency generator. Change oil every 500 hrs of operation with min of annual or testing
040 041 042 043 044	Dix Dam Station Emergency Generator CT5 Emergency Generator CT6 Emergency Generator CT6 Emergency Generator CT7 Emergency Generator (Existing CI Emergency RICE < 500 HP)	NA/Work Practices	40 CFR 60.6655(a) and (e)	Hours	A non-resettable hour meter shall be installed on the emergency generator. Monitor usage hours monthly
045 046 047 048	Emergency Steam Plant Fire Pump Engine #1 Emergency Steam Plant Fire Pump Engine #2 Emergency Quench Water Pump Engine #1 Emergency Quench Water Pump Engine #2 (New CI Emergency RICE < 500 HP)	Certifed Engines	40 CFR 60.6209(a)	Hours	A non-resettable hour meter shall be installed prior to intial operaton of the emergency generator.
049	Emergency 752 HP Engine (New CI Emergency RICE > 500 HP)	Certifed Engine	40 CFR 60.6209(a)	Hours	A non-resettable hour meter shall be installed prior to intial operaton of the emergency generator.
050	New Ash/Gypsum Landfill and Haul Trucks	PM	401 KAR 52:020, Section 10 401 KAR 63:010	fugitives	VMT monthly and inspections (water usage , enclosures); Daily weekday (Monday- Friday) QV

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION II. MONITORING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Monitored(7)	Description of Monitoring(8)*
"051 052	Emergency Tier II 1220 HP Diesel RICE Emergency Tier II 1220 HP Diesel RICE (New CI Emergency RICE > 500 HP)	Certifed Engine	40 CFR 60.6209(a)	Hours	A non-resettable hour meter shall be installed prior to intial operaton of the emergency generator.

* See text of cited rule or the 2009 Consent Decree for a complete description of the applicable requirement.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)*	Description of Recordkeeping(10)*
01	Unit 1 Indirect Heat Exchanger	PM	401 KAR 52:055 401 KAR 52:020 Section 10	Opacity	Method 9 every 14 operating days (FGD stack) Performance Tests; CEM data from FGD stack
		NA	401 KAR 52:020 Section 10	ESP Maintenance	Maintain records regarding maintenance of the ESP.
		NA	401 KAR 52:020 Section 10 40 CFR 64.6(c)	Process Information	Heat, sulfur and ash content of fuels to develop a monthly average, rate of fuel burned, average electrical output daily, minimum and maximum hourly generation rate daily. Data from CEMs, all compliance tests Date, time and duration of each startup and shutdown event Cause and corrective actions associated with exceedances
		SO2	401 KAR 52:020 Section 10	SO2	Maintain records of CEMS data.
		Opacity	401 KAR 61:005 Section 3(16)(f) and 401 KAR 61:015 Section 6	Opacity	Method 9 every 14 operating days (FGD stack)
		SAM	401 KAR 51:017	473.1 tons for Units 1-3	Monthly cals/log with 12 month rolling SAM emissions
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable recording provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)*	Description of Recordkeeping(10)*
02	Unit 2 Indirect Heat Exchanger	PM	401 KAR 52:055 401 KAR 52:020 Section 10	Opacity	Method 9 every 14 operating days (FGD stack) Performance Tests; CEM data from FGD stack
		NA	401 KAR 52:020 Section 10	ESP Maintenance	Maintain records regarding maintenance of the ESP.
		NA	401 KAR 52:020 Section 10 40 CFR 64.6(c)	Process Information	Heat, sulfur and ash content of fuels to develop a monthly average, rate of fuel burned, average electrical output daily, minimum and maximum hourly generation rate daily. Data from CEMs, all compliance tests Date, time and duration of each startup and shutdown event Cause and corrective actions associated with exceedances
		SO2	401 KAR 52:020 Section 10	SO2	Maintain records of CEMS data.
		Opacity	401 KAR 61:005 Section 3(16)(f) and 401 KAR 61:015 Section 6	Opacity	Maintain records of COMS data. The percentage of COMS data showing excursions above the opacity standard in each calendar quarter shall be computed and recorded. If bypass is in operation Method 9 every 14 operating days (FGD stack)
		SAM	401 KAR 51:017	473.1 tons for Units 1-3	Monthly cals/log with 12 month rolling SAM emissions
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable recording provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.

Imber

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)*	Description of Recordkeeping(10)*
03	Unit 3 Indirect Heat Exchanger	PM	401 KAR 61:005 Section 3(16)(f) and 401 KAR 61:015 Section 6	PM	Maintain records of PM CEM data. Records of excursions (above indicator level) are reported in the semi-annual reports. Performance Tests
			401 KAR 52:020 Section 10	PJFF, SCR, FGD Maintenance	Maintain records regarding maintenance of the controls
		NA	401 KAR 52:020 Section 10 40 CFR 64.6(c)	Process Information	Heat, sulfur and ash content of fuels to develop a monthly average, rate of fuel burned, average electrical output daily, minimum and maximum hourly generation rate daily. Data from CEMs, all compliance tests Date, time and duration of each startup and shutdown event Cause and corrective actions associated with exceedances
			2009 Consent Decree	PM	Maintain records of PM CEMS data.
		SO2	401 KAR 52:020 Section 10	SO2	Maintain records of SO2 CEMS data.
		NOx	401 KAR 52:020 Section 10	NOx	Maintain records of NOx CEMS data.
		All	2009 Consent Decree	Heat Input, Coal Burned, and Composite Fuel Sampling	Maintain records of the calculated heat input rate, mass of coal burned, and composite fuel sampling analysis results.
		Opacity	401 KAR 52:020 Section 10	Opacity	Method 9 every 14 operating days (FGD stack)
		SAM	2009 Consent Decree 401 KAR 51:017	473.1 tons for Units 1-3	Monthly cals/log with 12 month rolling SAM emissions
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable recording provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)*	Description of Recordkeeping(10)*
07	Coal Handling Operations 07	PM	401 KAR 52:020 Section 10	fugitives	Maintain records of the coal received (monthly); inspections of enclosures (monthly) ; maintenance records
09	Coal Handling Operations 09	Opacity	401 KAR 52:020 Section 10	Coal Processed	Maintain records of the coal received and processed.
			401 KAR 52:020 Section 10	Maintenance	Maintain records of maintenance on coal processing equipment and associated air pollution control equipment.
13	Coal Handling Operations 13	PM/Opacity	401 KAR 52:020 Section 10	Coal Processed	Maintain records of the coal received and processed.
			401 KAR 52:020 Section 10	Maintenance	Maintain records of maintenance on coal processing equipment and associated air pollution control equipment (cyclone, fabric filter).
16	Coal Crushing	PM/Opacity	401 KAR 52:020 Section 10	Coal Processed and Hours of Operation	Maintain records of the coal processed/burned and the hours of operation.
			401 KAR 52:020 Section 10	Maintenance	Maintain records of maintenance on coal processing equipment and associated air pollution control equipment (wet scrubber).
21	Dry Fly Ash Handling	PM/Opacity	401 KAR 52:020 Section 10	Ash Processed and Hours of Operation	Monthly records of the ash processed and the hours of operation
			401 KAR 52:020 Section 10	Maintenance	Maintain records of maintenance on ash handling equipment and associated air pollution control equipment.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)*	Description of Recordkeeping(10)*
023 024 025 026 029	Combustion Turbine Unit 9 Combustion Turbine Unit 10 Combustion Turbine Unit 8 Combustion Turbine Unit 11 Combustion Turbine Unit 5	NOx	401 KAR 59:005 Section 3	CEMS Records	Maintain records of CEMS output.
			401 KAR 59:005 Section 3	SSM Events	Maintain records of any startup, shutdown, or malfunction in the operation of the emission units, any malfunction of the air pollution control equipment, or any period during which the CEMS is inoperative.
			401 KAR 52:020, Section 10	Maintenance	Maintain records of maintenance and operation/use of the water injection control systems.
		SO2	401 KAR 52:060	Fuel Sulfur Content	Maintain a log of all sulfur content measurements as required in the approved custom fuel sulfur-monitoring plan.
		All	40 CFR 63.334(a)	Fuel Usage	Maintain records of daily natural gas and number two fuel oil usage.
		All	401 KAR 52:020, Section 10	Hours of Operation and Power Output	Maintain a daily log of all hours of operation and power output (in MW) for each combustion turbine.
027 028	Combustion Turbine Unit 6 Combustion Turbine Unit 7	NOx	401 KAR 59:005 Section 3	CEMS Records	Maintain records of CEMS output.
			401 KAR 59:005 Section 3	SSM Events	Maintain records of any startup, shutdown, or malfunction in the operation of the emission units, any malfunction of the air pollution control equipment, or any period during which the CEMS is inoperative.
			401 KAR 52:020, Section 10	Maintenance	Maintain records of maintenance and operation/use of the water injection control systems.
		SO2	401 KAR 52:060	Fuel Sulfur Content	Maintain a log of all sulfur content measurements as required in the approved custom fuel sulfur-monitoring plan.
		All	40 CFR 63.334(a)	Fuel Usage	Maintain records of daily natural gas and number two fuel oil usage.
		All	401 KAR 52:020, Section 10	Hours of Operation and Power Output	Maintain a daily log of all hours of operation and power output (in MW) for each combustion turbine.

Imber

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)*	Description of Recordkeeping(10)*
030 031	Limestone Truck Dump Station #1 Limestone Truck Dump Station #2	PM	401 KAR 52:020 Section 10	Material processed	Maintain records of monthly material processed and maintenance .
		Opacity	401 KAR 52:020 Section 10	Opacity	Maintain log of visible emissions observations.
032 033 034	Limestone Stacking Tube Limestone Reclaim Conveyor #1 Limestone Reclaim Conveyor #2	PM	401 KAR 52:020 Section 10	Material processed	Maintain records of monthly material processed and maintenance .
		Opacity	401 KAR 52:020 Section 10	Opacity	Maintain log of visible emissions observations.
35	Road Fugitives from Truck Traffic on Unpaved and Paved Roads	PM	401 KAR 52:020 Section 10	fugitives	Maintain records of the VMT (monthly); inspections of controls/truck water sprayers (monthly) ; maintenance records
036 037 038	Unit 1 Cooling Tower with Drift Eliminators Unit 2 Cooling Tower with Drift Eliminators Unit 3 Cooling Tower with Drift Eliminators	PM	401 KAR 52:020 Section 10	fugitives	Inspections of controls/drift eliminators (monthly) ; maintenance records
039	Dix Dam Crest Gate Emergency Generator - 40 HP (Existing SI Emergency < 500 HP)	Work Practices	40 CFR 63.6655(a), (e), (f)	Notifications Maintenance Hours	Malfunctions, if applicable; maintenance records; hours of operation (verify emergency usage only)
040 041 042 043 044	Dix Dam Station Emergency Generator CT5 Emergency Generator CT6 Emergency Generator CT6 Emergency Generator CT7 Emergency Generator (Existing CI Emergency RICE < 500 HP)	Work Practices	401 KAR 52:020, Section 10	Fuel Hours Deviations	Fuel (usage gallons/monthly records) Hour (monthly) Deviations (Semi-Annual Reports)
045 046 047 048	Emergency Steam Plant Fire Pump Engine #1 Emergency Steam Plant Fire Pump Engine #2 Emergency Quench Water Pump Engine #1 Emergency Quench Water Pump Engine #2 (New CI Emergency RICE < 500 HP)		40 CFR 63, Subpart ZZZZ	Hours Deviations Certification	Hours (monthly) Deviations (note in semi-annual reports, if applicable) Certification
049	Emergency 752 HP Engine (New CI Emergency RICE > 500 HP)		40 CFR 63, Subpart ZZZZ	Hours Deviations Certification	Hours (monthly) Deviations (note in semi-annual reports, if applicable) Certification
050	New Ash/Gypsum Landfill and Haul Trucks	PM	401 KAR 52:020, Section 10	fugitives	Daily QVs Records of processing rate (tons, VMT) Maintenance of controls
"051 052	Emergency Tier II 1220 HP Diesel RICE Emergency Tier II 1220 HP Diesel RICE (New CI Emergency RICE > 500 HP)		40 CFR 63, Subpart ZZZZ	Hours Deviations Certification	Hours (monthly) Deviations (note in semi-annual reports, if applicable) Certification

Imber

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION III. RECORDKEEPING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Recorded(9)*	Description of Recordkeeping(10)*

* See text of cited rule or the 2009 Consent Decree for a complete description of the applicable requirement.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION IV. REPORTING REQUIREMENTS[1]

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Reported(11)	Description of Reporting(12)*
01	Unit 1 Indirect Heat Exchanger	SO2 PM SAM	401 KAR 61:005 Section 3(15)	Excess Emissions Startups if exceedance occur SAM	Submit quarterly excess emission reports for CEMS. Startup & SAM data in semi-annual report
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable reporting provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.
02	Unit 2 Indirect Heat Exchanger	SO2 PM SAM	401 KAR 61:005 Section 3(16)	Excess Emissions Startups if exceedance occur SAM	Submit quarterly excess emission reports for CEMS. Startup & SAM data in semi-annual report
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable reporting provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.
03	Unit 3 Indirect Heat Exchanger	SO2 PM SAM	401 KAR 61:005 Section 3(16)	Excess Emissions Startups if exceedance occur SAM	Submit quarterly excess emission reports for CEMS. Startup & SAM data in semi-annual report
		All	2009 Consent Decree	Compliance Determination	Submit semi-annual compliance and PM CEMS data report to EPA within sixty days after the end of each half of the calendar year.
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable reporting provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.
07	Coal Handling Operations 07			General	Title V Reports
09	Coal Handling Operations 09				Semi-annual reporting of Method 22's that exceed 20% opacity
13	Coal Handling Operations 13			General	Title V Reports
16	Coal Crushing			General	Title V Reports
21	Dry Fly Ash Handling			General	CAM plan (exceedances); Semi-Annual Reports
023 024 025 026 029	Combustion Turbine Unit 9 Combustion Turbine Unit 10 Combustion Turbine Unit 8 Combustion Turbine Unit 11 Combustion Turbine Unit 5	NOx	401 KAR 59:005 Section 3	Excess Emissions	Submit quarterly excess emission reports for the oxygen continuous monitoring system.
		SO2	401 KAR 60.334(c)	Excess Emissions	Submit quarterly excess emissions reports for sulfur dioxide emissions from the turbines.
027 028	Combustion Turbine Unit 6 Combustion Turbine Unit 7	NOx	401 KAR 59:005 Section 3	Excess Emissions	Submit quarterly excess emission reports for the oxygen continuous monitoring system.
		SO2	401 KAR 60.334(c)	Excess Emissions	Submit quarterly excess emissions reports for sulfur dioxide emissions from the turbines.
030 031	Limestone Truck Dump Station #1 Limestone Truck Dump Station #2	PM		Fugitives	Report opacity observations per 40 CFR 60.676(f).

032 033 034	Limestone Stacking Tube Limestone Reclaim Conveyor #1 Limestone Reclaim Conveyor #2	PM	NSPS Subpart OOO	PM	Report containing the results of all performance tests, including reports of opacity observations per 40 CFR 60.676(f).
35	Road Fugitives from Truck Traffic on Unpaved and Paved Roads			General	Title V Reports
036 037 038	Unit 1 Cooling Tower with Drift Eliminators Unit 2 Cooling Tower with Drift Eliminators Unit 3 Cooling Tower with Drift Eliminators			General	Title V Reports
039	Dix Dam Crest Gate Emergency Generator - 40 HP (Existing SI Emergency < 500 HP)		40 CFR 63, Subpart ZZZZ	General	Deviations, and Title V monitoring, recordkeeping and reporting requirements
040 041 042 043 044	Dix Dam Station Emergency Generator CT5 Emergency Generator CT6 Emergency Generator CT6 Emergency Generator CT7 Emergency Generator (Existing CI Emergency RICE < 500 HP)		40 CFR 63, Subpart ZZZZ	Hours Deviations Maintenance	Hours, Deviations, and Title V monitoring, recordkeeping and reporting requirements
045 046 047 048	Emergency Steam Plant Fire Pump Engine #1 Emergency Steam Plant Fire Pump Engine #2 Emergency Quench Water Pump Engine #1 Emergency Quench Water Pump Engine #2 (New CI Emergency RICE < 500 HP)		40 CFR 63, Subpart ZZZZ	General	Permittee is not required to submit an initial notification per 40 CFR 60.4214(b) General Reporting requirements
049	Emergency 752 HP Engine (New CI Emergency RICE > 500 HP)		40 CFR 63, Subpart ZZZZ	General	Permittee is not required to submit an initial notification per 40 CFR 60.4214(b) General Reporting requirements
050	New Ash/Gypsum Landfill and Haul Trucks	PM	401 KAR 52:020, Section 10	General	Title V monitoring, recordkeeping and reporting requirements
"051 052	Emergency Tier II 1220 HP Diesel RICE Emergency Tier II 1220 HP Diesel RICE (New CI Emergency RICE > 500 HP)		40 CFR 63, Subpart ZZZZ	General	Permittee is not required to submit an initial notification per 40 CFR 60.4214(b) General Reporting requirements

[1] Annual compliance certifications will be submitted covering all emission identified emission units. Additionally, reports of stack tests will be submitted for those emission units requiring annual stack tests as noted in Section V of this form.

* See text of cited rule or the 2009 Consent Decree for a complete description of the applicable requirement.

DEP7007V
continued

APPLICANT NAME: EW Brown

SECTION V. TESTING REQUIREMENTS

KYEIS No.(1)	Emission Unit Description(2)	Contaminant(3)	Origin of Requirement or Standard(4)	Parameter Tested(13)	Description of Testing(14)*
01	Unit 1 Indirect Heat Exchanger	PM	401 KAR 50:045 401 KAR 50:055	PM	Stack tests within (1) year of renewal permit and then within the 3rd year of the permit Method 9 every 14 days from FGD/common stack.
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable testing provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.
02	Unit 2 Indirect Heat Exchanger	PM	401 KAR 50:045 401 KAR 50:055	PM	Stack tests and opacity trigger level within (1) year of renewal permit and then within the 3rd year of the permit Method 9 every 14 days from FGD/common stack.
		SAM	401 KAR 50:055 40 CFR 64.6(c)		SAM Performance testing with Unit 2 PM Performance test
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable testing provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.
03	Unit 3 Indirect Heat Exchanger	PM	2009 Consent Decree/401 KAR 50:045 401 KAR 50:055	PM	Conduct a stack test for PM on the common stack servicing Unit 3 at least one time each calendar year. Test must be at least six months apart. Method 9 every 14 days from FGD/common stack.
		SAM	401 KAR 50:055 40 CFR 64.6(c)		Annual SAM Performance testing (FGD stack)
		HAPS	40 CFR 63, Subpart UUUUU	NA	Comply with all applicable testing provisions of 40 CFR 63.10030 through 40 CFR 63.10033, no later than April 16, 2015 or by the extension date.
07	Coal Handling Operations 07				NA
09	Coal Handling Operations 09	Opacity	40 CFR 60.253(a)		Quarterly Method 22
13	Coal Handling Operations 13	Opacity	401 KAR 50:020, Section 10	opacity	Weekly QV and Method 9 if triggered
16	Coal Crushing	Opacity	401 KAR 50:020, Section 10	opacity	Weekly QV and Method 9 if triggered
21	Dry Fly Ash Handling	PM	401 KAR 50:055	PM	Performance test for startup
023 024 025 026 029	Combustion Turbine Unit 9 Combustion Turbine Unit 10 Combustion Turbine Unit 8 Combustion Turbine Unit 11 Combustion Turbine Unit 5	NOx SO2	40 CFR 60.8(b)(3)	NOx SO2	Compute the NOx and SO2 emissions of the fuel being fired by Division approved alternate procedures as listed in Appendix D and E of 40 CFR 75.
			40 CFR 60.335(b)	NOx SO2	In conducting performance tests required by 40 CFR 60.8 use the Administrator approved alternate procedures as provided for in 40 CFR 60.8(b)(3).
			40 CFR 60.335(d)	SO2	Determine compliance with the sulfur content standard using appropriate ASTM methods as required by 40 CFR 60.335(d).
			40 CFR 60.334(b)	NOx SO2	Use the methods specified in 40 CFR 60.335(a) and (d) to determine the nitrogen and sulfur contents of the fuel being burned.
027 028	Combustion Turbine Unit 6 Combustion Turbine Unit 7	NOx SO2	40 CFR 60.8(b)(3)	NOx SO2	Compute the NOx and SO2 emissions of the fuel being fired by Division approved alternate procedures as listed in Appendix D and E of 40 CFR 75.

			40 CFR 60.335(b)	NOx SO2	In conducting performance tests required by 40 CFR 60.8 use the Administrator approved alternate procedures as provided for in 40 CFR 60.8(b)(3).
			40 CFR 60.335(d)	SO2	Determine compliance with the sulfur content standard using appropriate ASTM methods as required by 40 CFR 60.335(d).
			40 CFR 60.334(b)	NOx SO2	Use the methods specified in 40 CFR 60.335(a) and (d) to determine the nitrogen and sulfur contents of the fuel being burned.
030 031	Limestone Truck Dump Station #1 Limestone Truck Dump Station #2		401 KAR 50:055	fugitives	Quarterly Method 9, Method 9 if triggered
032 033 034	Limestone Stacking Tube Limestone Reclaim Conveyor #1 Limestone Reclaim Conveyor #2	PM and Opacity	40 CFR 60.675	PM & Opacity	Conducting initial performance tests required by 40 CFR 60.8 for PM and opacity. Use reference methods and procedures the test methods in Appendices A-1 through A-7 of 40 CFR 60.
35	Road Fugitives from Truck Traffic on Unpaved and Paved Roads				NA
036 037 038	Unit 1 Cooling Tower with Drift Eliminators Unit 2 Cooling Tower with Drift Eliminators Unit 3 Cooling Tower with Drift Eliminators				NA
039	Dix Dam Crest Gate Emergency Generator - 40 HP (Existing SI Emergency < 500 HP)				NA
040 041 042 043 044	Dix Dam Station Emergency Generator CT5 Emergency Generator CT6 Emergency Generator CT6 Emergency Generator CT7 Emergency Generator (Existing CI Emergency RICE < 500 HP)				NA
045 046 047 048	Emergency Steam Plant Fire Pump Engine #1 Emergency Steam Plant Fire Pump Engine #2 Emergency Quench Water Pump Engine #1 Emergency Quench Water Pump Engine #2 (New CI Emergency RICE < 500 HP)	CO, NOX, PM, NMHC	NSPS Subpart IIII, 60.4211(b)	CO, NOX, PM, NMHC	Conduct initial performance test within 60 days of achieving maximum production but no later than 180 days after startup, in accordance with 60.4212. NA for certified engine
049	Emergency 752 HP Engine (New CI Emergency RICE > 500 HP)	CO, NOX, PM, NMHC	NSPS Subpart IIII, 60.4211(b)	CO, NOX, PM, NMHC	Conduct initial performance test within 60 days of achieving maximum production but no later than 180 days after startup, in accordance with 60.4212. NA for certified engine
050	New Ash/Gypsum Landfill and Haul Trucks				NA
"051 052	Emergency Tier II 1220 HP Diesel RICE Emergency Tier II 1220 HP Diesel RICE (New CI Emergency RICE > 500 HP)	CO, NOX, PM, NMHC	NSPS Subpart IIII, 60.4211(b)	CO, NOX, PM, NMHC	Conduct initial performance test within 60 days of achieving maximum production but no later than 180 days after startup, in accordance with 60.4212. NA for certified engine

* See text of cited rule or the 2009 Consent Decree for a complete description of the applicable requirement.

Commonwealth of Kentucky
Natural Resources & Environmental Protection Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007Y
Good Engineering Practice (GEP) Stack Height Determination

Complete only for stacks 65m or taller

EMISSIONS UNIT # 01, 02, 03
EMISSIONS POINT # 017

EXHAUST POINT INFORMATION		
1) Flow diagram designation of exhaust point New Main Stack		
2) Description of exhaust point (stack, vent, roof monitor, indoors, etc.). If the exhaust point discharges indoors, complete items 3 through 11 for the building exhaust nearest to the process operations emission unit. Stack for Units 1, 2, & 3		
3) Distance to nearest plant boundary from exhaust point discharge (ft): 1,200		
4) Discharge height above grade (ft): 561		
5) Good engineering practice (GEP) height, if known (ft): 585		
6) Diameter (or equivalent diameter) of exhaust point (ft): 26.7		
7) Exit gas flow rate:	a) Maximum (ACFM): 2,624,305	b) Minimum (ACFM):
8) Exit gas temperature:	a) @ maximum flow rate (˚F): 129	b) @ minimum flow rate (˚F):
9) Direction of exhaust (vertical, lateral, downward): Vertical		
10a) Latitude:	b) Longitude	
11a) UTM zone: 16 (NAD83)	b) UTM vertical (KM): 4,184.8943	c) UTM Horizontal (KM): 701.1779

NOTE: For a square or rectangular vent, the equivalent diameter is 1.128 times the square root of the stack's area

BUILDING DIMENSION INFORMATION			
12) Dimensions of building on which exhaust point is located	a) Length (ft) NA – Not located on building	b) Width (ft)	c) Height (ft)
13) Distance to nearest building (ft): 445			
14) Dimension of this nearest building	a) Length (ft): 220	b) Width (ft): 433	d) Height (ft): 234 (Boiler Roof Loovers)

15) List all emission units and control devices serviced by this exhaust point.

Name	Flow Diagram Designation
a) Unit 1 Indirect Heat Exchanger	01
b) Unit 2 Indirect Heat Exchanger	02
c) Unit 3 Indirect Heat Exchanger	03
d)	
e)	
f)	
g)	
h)	
i)	

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection

DIVISION FOR AIR QUALITY

DEP7007DD

INSIGNIFICANT ACTIVITIES

INSIGNIFICANT ACTIVITY CRITERIA

1. Emissions from insignificant activities shall be counted toward the source's potential to emit;
2. Emissions from the activity shall not be subject to a federally enforceable requirement other than generally applicable requirements that apply to all activities and affected facilities such as 401 KAR 59:010, 61:020, 63:010, and others deemed generally applicable by the Cabinet;
3. The potential to emit a regulated air pollutant from the activity or affected facility shall not exceed 5 tons/yr.
4. The potential to emit of a hazardous air pollutant from the activity or affected facility shall not exceed 1,000 pounds/yr., or the deminimis level established under Section 112(g) of the Act, whichever is less;
5. The activity shall be included in the permit application, identifying generally applicable and state origin requirements.

Description of Activity Including Rated Capacity	Generally Applicable Regulations Or State Origin Requirements	Does the Activity meet the Insignificant Activity Criteria Listed Above?
Refer to attached Supplement to Form DEP7007DD		

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 Ralph Bowling
Authorized Signature

7 / 10 / 15
Date

Ralph Bowling
Typed or Printed Name of Signatory

Vice President Power Production
Title of Signatory

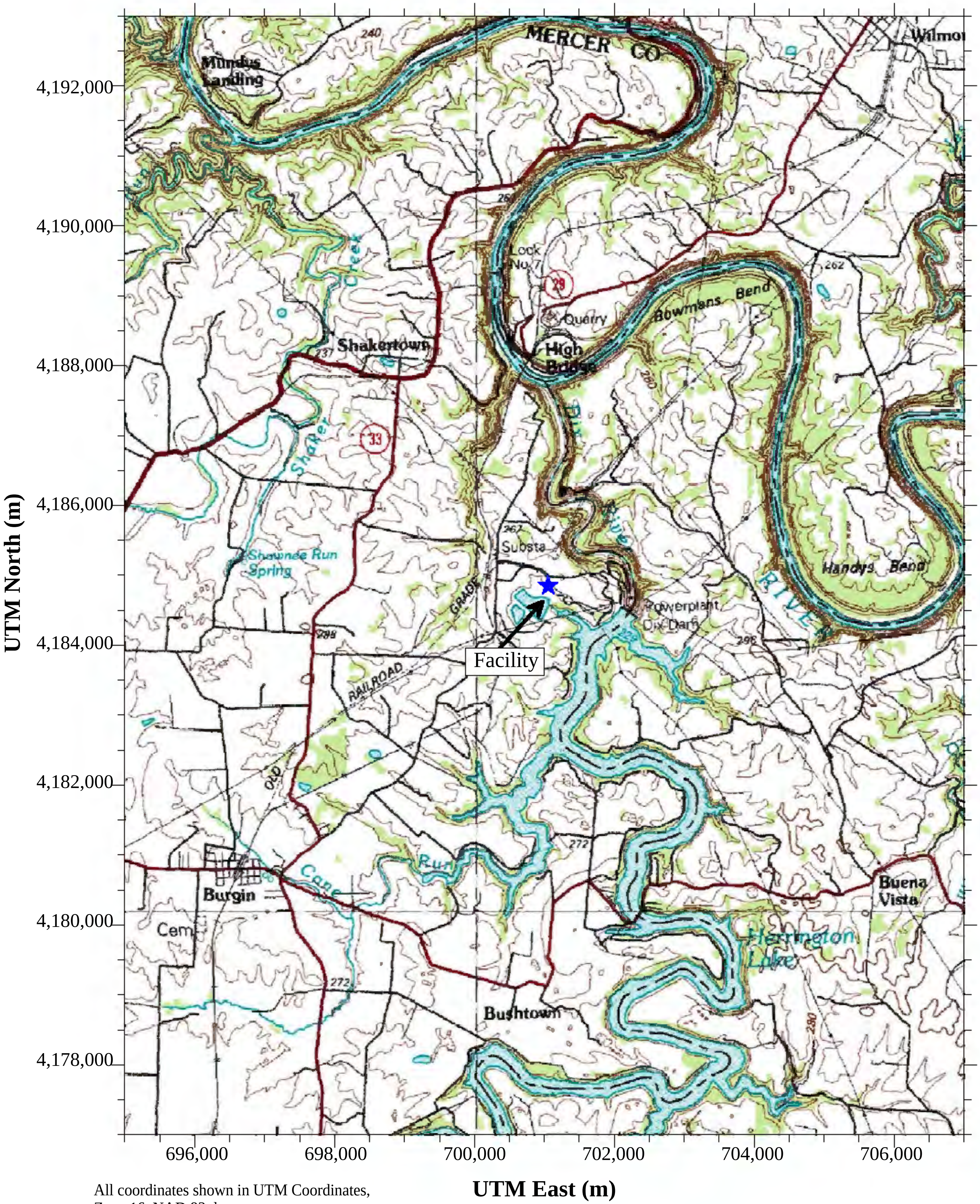
1. Station fuel-oil tanks (2 @ 1,100.,000 each)	None	Yes
*2. Fuel-oil tanks (various installed before 1973)**	*None*	*Yes*
3. Turbine oil tanks for Unit 3 (2 @ 9,000 gallons)	*None*	*Yes*
4. Unleaded gasoline storage tanks	*None*	*Yes*
5. Turbine oil reservoirs for CT6 & 7 & Unit 3 (3 @ 6,500 gallons)	*None*	*Yes*
6. Turbine oil tanks for Units 1 &2 (2 @ 3,600 gallons)	*None*	*Yes*
7. Turbine oil reservoirs for CT5, 8, 9, 10, 11 (5 @ 4,000 gallons)	*None*	*Yes*
8. Turbine oil reservoirs for Units 1 & 2 (2 @ 3,000 gallons)	*None*	*Yes*
~~*9. SO3, sulfur trioxide, injection system (Emission Unit 1)*~~ *REMOVED*	~~*None*~~	~~*Yes*~~
10. Thermal evaporation of boiler chemical cleaning solutions	*401 KAR 59:010*	*Yes*
11. Burning of Off-Specification Used Oil for Energy Recovery	*401 KAR 61:020*	*Yes*
12. Natural Gas Fired Fuel Heaters (less than 7 MMBtu/hr each)	*401 KAR 61:015*	*Yes*
13. Kerosene Tank (1 @ 500 gallons)	*None*	*Yes*
14. Distillate Oil and/or Propane Coal Belt Heaters	*None*	*Yes*
15. Gypsum Slurry Transfer from FGD to Gypsum Dewatering	*401 KAR 59:010*	*Yes*
16. Gypsum Dewatering Process	*401 KAR 59:010*	*Yes*
17. Gypsum Storage Pile	*401 KAR 63:010*	*Yes*
18. Limestone Storage Pile	*401 KAR 63:010*	*Yes*
19. Limestone Reclaim Maintenance Tunnel Exhaust Vent)	*401 KAR 59:010*	*Yes*
20. Sorbent Storage Silos (for SO3 Mitigation)	*401 KAR 59:010*	*Yes*
21. Natural Gas Distillate tank (2000 gallons)	*None*	*Yes*
22. Diesel Fuel tanks for emergency generators(3 @ 391 gallons)	*None*	*Yes*
23. Diesel Fuel tank for emergency fire pump (300 gallons)	*None*	*Yes*
24. Diesel Fuel tank for emergency generator(275 gallons)	*None*	*Yes*
25. Diesel Fuel tank for emergency generator (837 gallons)	*None*	*Yes*
26. Diesel Fuel tanks for emergency fire pumps & FGD building(2 @ 440 gallons)	*None*	*Yes*
27. Diesel Fuel tanks for emergency fire pumps & FGD building(2 @ 550 gallons)	*None*	*Yes*
28. Turbine oil reservoir for Unit 3 feed pump (2,000 gallons)	*None*	*Yes*
29. Turbine oil reservoir for Unit 1 seal oil (55 gallons)	*None*	*Yes*
30. Turbine oil reservoir for Unit 2 seal oil (75 gallons)	*None*	*Yes*
31. Turbine oil reservoir for Unit 3 seal oil (150 gallons)	*None*	*Yes*
32. Turbine oil reservoir for Unit 1 lube oil (300 gallons)	*None*	*Yes*
33. Turbine oil reservoir for Unit 2 lube oil (2 @ 55 gallons)	*None*	*Yes*
34. Turbine oil reservoir for Unit 3 lube oil (2 @ 400 gallons)	*None*	*Yes*
35. Lab Fume Hood	*None*	*Yes*
36. Hydraulic oil tanks (2 @300 and 1 @ 500 gallons)	*None*	*Yes*
37. PAC Storage Silos	*401 KAR 59:010*	*Yes*
38. Bottom Ash Transport	*401 KAR 63:010*	*Yes*
39. Fly Ash Transport	*401 KAR 63:010*	*Yes*
40. Gypsum Transport	*401 KAR 63:010*	*Yes*
41. Landfill Truck Loading and Unloading	*401 KAR 63:010*	*Yes*
42. Active Area of the Landfill (Wind Erosion)	*401 KAR 63:010*	*Yes*
43. Slipstream Carbon Dioxide (C02) capture System – Research	*401 KAR 63:010*	*Yes*
44. Bottom As/1 Handling Including storage pile (associated with new landfill operations)	*401 KAR 63:010*	*Yes*
45. Fly Ash Handling Including load out to trucks (associated with new landfill operations)	*401 KAR 63:010*	*Yes*
46. Fly Ash Filter/Separator Units (2) (associated with new landfill operations)	*401 KAR 63:010*	*Yes*
47. Fly Ash Storage Silos (2) (associated with new landfill operations)	*401 KAR 63:010*	*Yes*
48. Gypsum Processing Including storage p/le (associated with new landfill operations)	*401 KAR 63:010*	*Yes*
** includes (2) 525,000 gallon; (2) 15,000 gallon; (1) 275 gallon #2 fuel oil tanks; (1) 1650 gallon and (1) 1000 gallon diesel tanks.*		

APPENDIX B – Maps & Site Plans

APPENDIX B

AREA MAP, SITE PLAN, AND AERIAL PHOTOS

Figure B-1. Area Map Showing Location of Brown Station



All coordinates shown in UTM Coordinates, Zone 16, NAD 83 datum.

GENERAL NOTES

1. ALL COORDINATES AND BEARINGS ARE BASED ON THE KENTUCKY STATE PLANE, SOUTH ZONE, NAD 83.
2. EXISTING SITE CONDITIONS AND TOPOGRAPHY ARE TAKEN TAKEN FROM AN AERIAL SURVEY DATED SEPTEMBER 1, 2005 BY L. ROBERT KIMBALL AND ASSOCIATES, INC. ADDITIONAL FIELD SURVEY DATA AND LOCATIONS OF UNDERGROUND LINES HAS BEEN PROVIDED BY FULLER, MOSSBARGER, SCOTT AND MAY, INC. LEXINGTON KENTUCKY.
3. ALL GRADES SHOWN AS PROPOSED FINISHED GRADES INCLUDE SURFACE TREATMENTS SUCH AS TOPSOIL OR PAVEMENT. MAKE ALLOWANCES DURING EARTHWORK OPERATIONS FOR THESE SURFACE TREATMENTS.
4. ALL WORK SHOWN ON THE CIVIL DRAWINGS SHALL BE ACCOMPLISHED IN ACCORDANCE WITH THE REQUIREMENTS OF THE FOLLOWING SPECIFICATION SECTIONS:

TITLE	SECTION No.
DEMOLITION	A2AP.750.210.02050
TOPSOIL REMOVAL AND STOCKPILING	A2AP.750.210.02115
EARTHWORK	A2AP.750.210.02200
ROCK DRILLING AND BLASTING	A2AP.750.210.02211
EXCAVATION, BACKFILL AND COMPACTION – STRUCTURES	A2APBR.750.210.02222
EXCAVATION, BACKFILL AND COMPACTION – UNDERGROUND PIPING	A2APBR.750.210.02224
BUILDING FLOOR SLAB BASE	A2AP.750.210.02231
AGGREGATE PAVEMENT BASE	A2AP.750.210.02232
EROSION CONTROL	A2AP.750.210.02270
RIPRAP	A2AP.750.210.02271
BITUMINOUS CONCRETE PAVING	A2AP.750.210.02513
PORTLAND CEMENT CONCRETE PAVING	A2AP.750.210.02515
STORM SEWER SYSTEMS AND CULVERTS	A2AP.750.210.02720
SANITARY SEWER SYSTEMS	A2AP.750.210.02730
CHAIN LINK FENCE – GALVANIZED	A2AP.750.210.02834
STRUCTURAL CONCRETE AND REINFORCING	A2AP.750.215.03300
GENERAL REQUIREMENTS–FIRE PROTECTION	A2AP.750.653.45000
UNDERGROUND AND OUTSIDE FIRE PROTECTION	A2AP.750.653.45005

CIVIL DRAWING LIST

BRO–C–00301	BROWN FGD PROJECT OVERALL SITE PLAN & GENERAL NOTES – CIVIL
BRO–C–00311	BROWN FGD PROJECT SITE PLAN – CIVIL
BRO–C–00312	BROWN FGD PROJECT SITE PLAN – CIVIL
BRO–C–00313	BROWN FGD PROJECT SITE PLAN – CIVIL
BRO–C–00314	BROWN FGD PROJECT SITE PLAN – CIVIL
BRO–C–00315	BROWN FGD PROJECT SITE PLAN – CIVIL
BRO–C–00316	BROWN FGD PROJECT SITE PLAN – CIVIL
BRO–C–00321	BROWN FGD PROJECT GRADING & DRAINAGE PLAN – CIVIL
BRO–C–00322	BROWN FGD PROJECT GRADING & DRAINAGE PLAN – CIVIL
BRO–C–00323	BROWN FGD PROJECT GRADING & DRAINAGE PLAN – CIVIL
BRO–C–00324	BROWN FGD PROJECT GRADING & DRAINAGE PLAN – CIVIL
BRO–C–00325	BROWN FGD PROJECT GRADING & DRAINAGE PLAN – CIVIL
BRO–C–00326	BROWN FGD PROJECT GRADING & DRAINAGE PLAN – CIVIL
BRO–C–00331	BROWN FGD PROJECT DEMOLITION PLAN – CIVIL
BRO–C–00332	BROWN FGD PROJECT DEMOLITION PLAN – CIVIL
BRO–C–00333	BROWN FGD PROJECT DEMOLITION PLAN – CIVIL
BRO–C–00334	BROWN FGD PROJECT DEMOLITION PLAN – CIVIL
BRO–C–00335	BROWN FGD PROJECT DEMOLITION PLAN – CIVIL
BRO–C–00336	BROWN FGD PROJECT DEMOLITION PLAN – CIVIL
BRO–C–00341	BROWN FGD PROJECT STORMWATER MANAGEMENT/EROSION CONTROL – EXISTING STORMWATER RUNOFF PATTERNS
BRO–C–00342	BROWN FGD PROJECT STORMWATER MANAGEMENT/EROSION CONTROL – PROPOSED STORMWATER RUNOFF PATTERNS
BRO–C–00351	BROWN FGD PROJECT TEMPORARY CONSTRUCTION PARKING AREA – STORMWATER MANAGEMENT/EROSION CONTROL
BRO–C–00352	BROWN FGD PROJECT TEMPORARY CONSTRUCTION LAYDOWN AREA – STORMWATER MANAGEMENT/EROSION CONTROL
BRO–C–00353	BROWN FGD PROJECT LIMESTONE HANDLING/TRAINING BUILDING AREA – STORMWATER MANAGEMENT/EROSION CONTROL
BRO–C–00354	BROWN FGD PROJECT WAREHOUSE AREA – STORMWATER MANAGEMENT/EROSION CONTROL
BRO–C–00355	BROWN FGD PROJECT FGD BUILDING/LIMESTONE PREPARATION AREA – STORMWATER MANAGEMENT/EROSION CONTROL
BRO–C–00361	BROWN FGD PROJECT UNDERGROUND UTILITIES – CIVIL
BRO–C–00362	BROWN FGD PROJECT UNDERGROUND UTILITIES – CIVIL
BRO–C–00363	BROWN FGD PROJECT UNDERGROUND UTILITIES PLAN – CIVIL
BRO–C–00364	BROWN FGD PROJECT UNDERGROUND UTILITIES PLAN – CIVIL
BRO–C–00365	BROWN FGD PROJECT UNDERGROUND UTILITIES PLAN – CIVIL
BRO–C–00366	BROWN FGD PROJECT UNDERGROUND UTILITIES PLAN – CIVIL
BRO–C–00371	BROWN FGD PROJECT PAVING AND SITE SECTIONS & DETAILS – CIVIL
BRO–C–00372	BROWN FGD PROJECT SECTIONS & DETAILS – CIVIL
BRO–C–00373	BROWN FGD PROJECT SECTIONS & DETAILS – CIVIL
BRO–C–00374	BROWN FGD PROJECT EROSION CONTROL SECTIONS & DETAILS – CIVIL
BRO–C–00375	BROWN FGD PROJECT ENLARGED PLANS, SECTIONS & DETAILS – CIVIL
BRO–C–00376	BROWN FGD PROJECT ENLARGED PLAN, SECTIONS & DETAILS – CIVIL
BRO–C–00377	BROWN FGD PROJECT SECTIONS & DETAILS – CIVIL
BRO–C–00378	BROWN FGD PROJECT ENLARGED PLAN, SECTIONS & DETAILS – CIVIL
BRO–C–00379	BROWN FGD PROJECT ENLARGED PLANS, SECTIONS & DETAILS – CIVIL
BRO–C–00380	BROWN FGD PROJECT ENLARGED PLANS, SECTIONS & DETAILS – CIVIL
BRO–C–00381	BROWN FGD PROJECT CROSS–SECTIONS & PROFILES – SHT. 1 – CIVIL
BRO–C–00382	BROWN FGD PROJECT PROFILES SHEET – CIVIL
BRO–C–00383	BROWN FGD PROJECT CROSS SECTIONS – CIVIL
BRO–C–00384	BROWN FGD PROJECT PROFILES SHEET – CIVIL
BRO–C–00391	BROWN FGD PROJECT FGD AREA EXCAVATION PLAN – CIVIL
BRO–C–00392	BROWN FGD PROJECT LIMESTONE AREA EXCAVATION PLAN – CIVIL

0' 100' 200' 400' 600' 800'

GRAPHIC SCALE 1"=200'

A	09/07/06	RJE	IFC
B	04/16/07	DS	ISSUED WITH SWPPP
C			

FLUOR

BROWN FGD PROJECT
OVERALL SITE PLAN & GENERAL NOTES
CIVIL

E. W. BROWN UNITS 1, 2 & 3

1"=200'
RJ EDENFIELD

an e-on company

A2AP

BRO–C–0301X __

Figure B-3. Brown Station Emission Point Location Plot

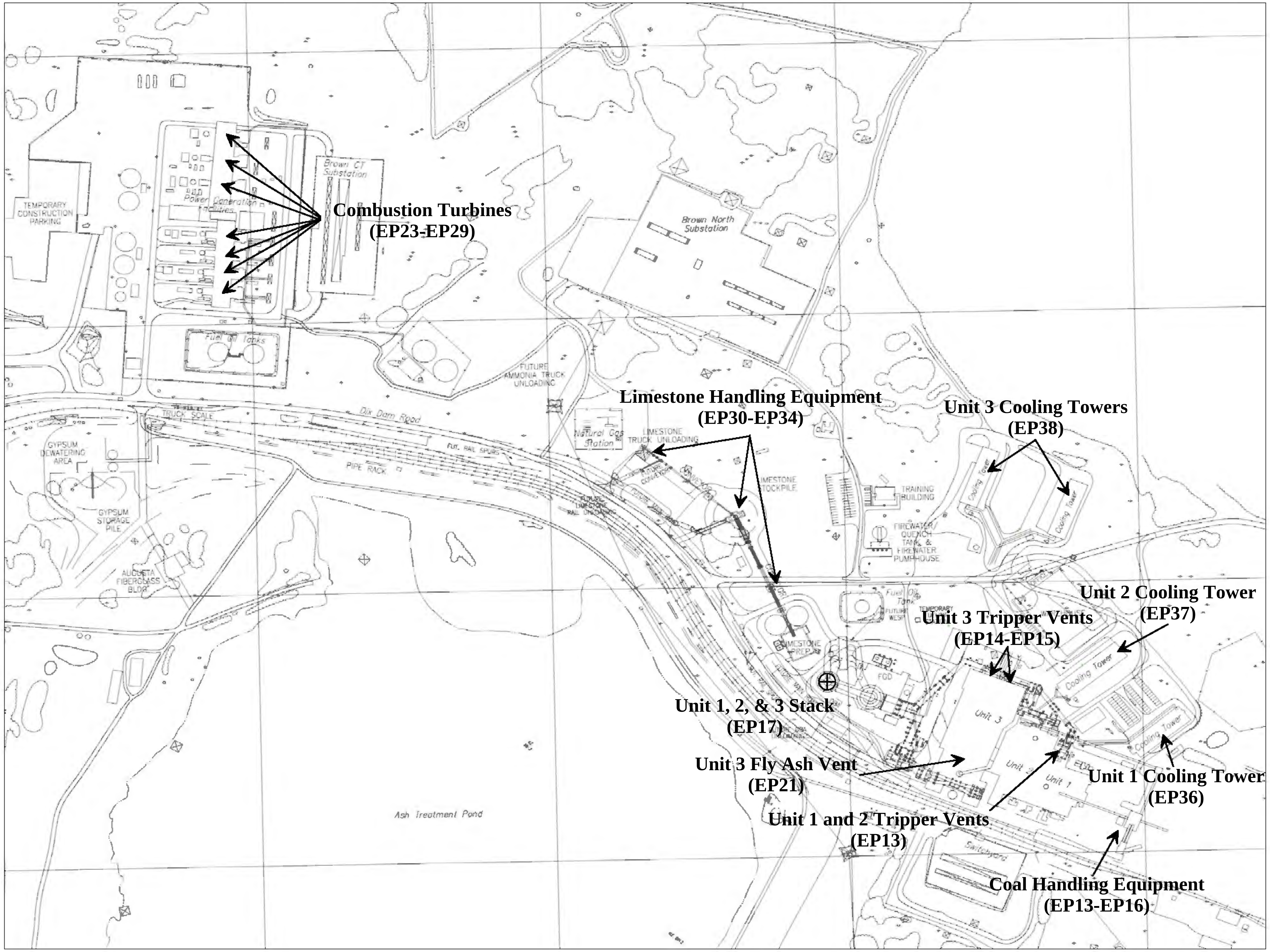


FIGURE B-4. AERIAL VIEW OF E.W. BROWN STATION LOOKING NORTHWEST

(Picture taken on August 1, 2008)

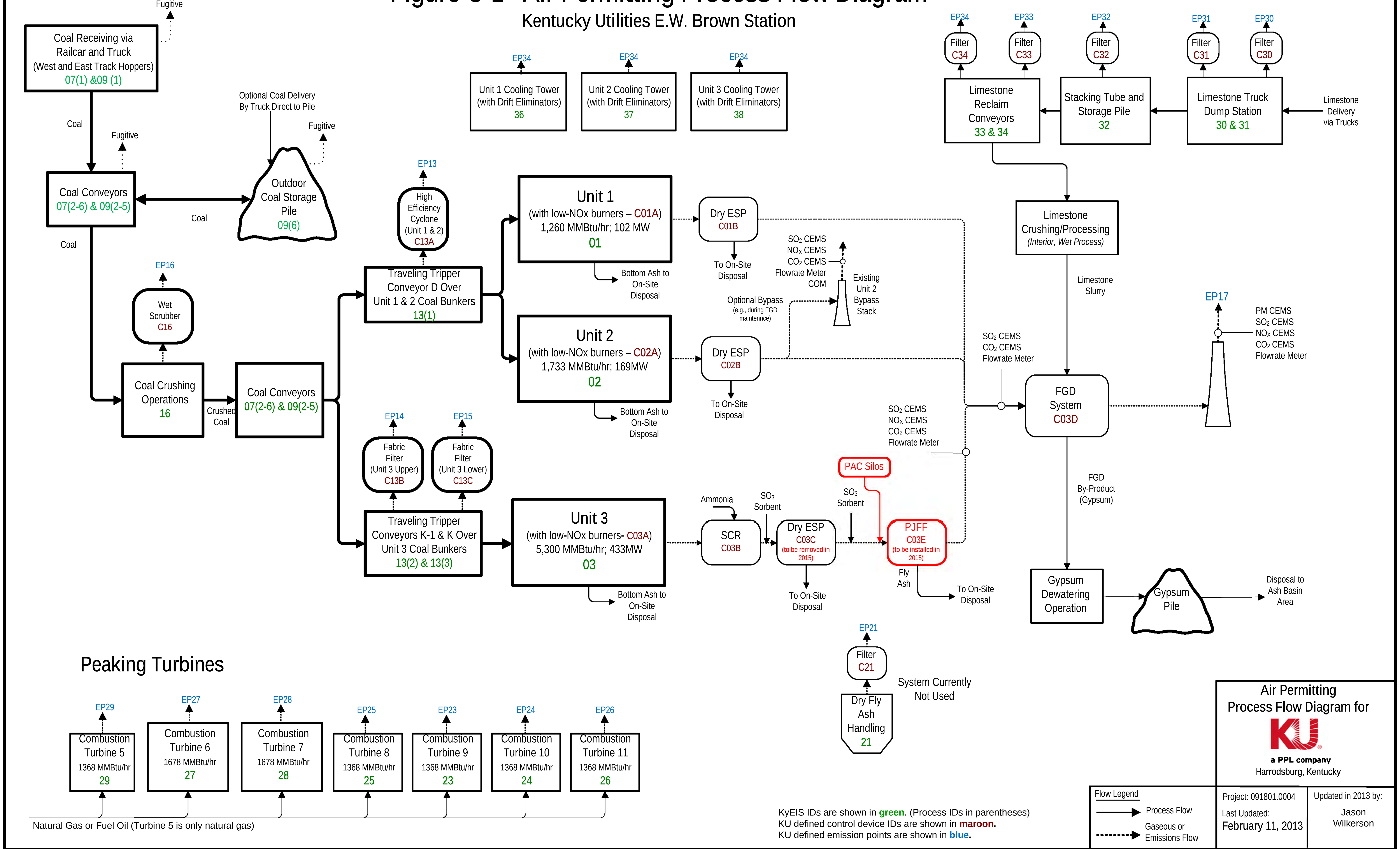
FIGURE B-5. AERIAL VIEW OF E.W. BROWN STATION LOOKING EAST SOUTHEAST

(Picture taken on August 1, 2008)

APPENDIX C – Process Flow Diagram

Figure C-1 Air Permitting Process Flow Diagram

Kentucky Utilities E.W. Brown Station



APPENDIX D –Emission Documentation

1. Emission Unit Index

Title V Permit ID#	KyEIS Equipment ID#	KyEIS Source ID#	KyEIS Process ID#	Emission Unit Description	KyEIS Process Description	Control Description	KU Control ID#	Emission Point ID#
3	4	5	6	7	8	9	10	11
01 (01)	COMB001	01	1	Unit 1 Indirect Heat Exchanger		Unit 1 Low NOX Burners	C01A	17
						Unit 1 Dry ESP	C01B	
						FGD for Units 1, 2 & 3	C03D	
02 (02)	COMB002	02	1	Unit 2 Indirect Heat Exchanger		Unit 2 Low NOX Burners	C02A	17
						Unit 2 Dry ESP	C02B	
						FGD for Units 1, 2 & 3	C03D	
03 (03)	COMB003	03	1	Unit 3 Indirect Heat Exchanger		Unit 3 Low NOX Burners	C03A	17
						Unit 3 SCR	C03B	
						Unit 3 PJFF	C03E	
						FGD for Units 1, 2 & 3	C03D	
07 (12, 14, 15)	EQPT014	07	1	Coal Handling Operations 07	West Track Hopper	Enclosures	C07A	Fugitive
			2		Conveyor A-1	Enclosures	C07B	
			3		Conveyor E	Enclosures	C07C	
			4		Conveyor F	Enclosures	C07D	
			5		Conveyor G	Enclosures	C07E	
			6		Conveyor H	Enclosures	C07F	
09 (12, 14)	EQPT015	09	1	Coal Handling Operations 09	East Track Hopper	Enclosures	C09A	Fugitive
			2		Conveyor A	Enclosures	C09B	
			3		Conveyor B	Enclosures	C09C	
			4		Conveyor C	Enclosures	C09D	
			5		Conveyor J	Enclosures	C09E	
			6		Coal Stockpile	Enclosures	C09F	
13 (14)	EQPT016	13	1	Coal Handling Operations 13	Conveyor D [Tripper for Units 1 & 2]	High Efficiency Cyclone	C13A	13
			2	Coal Handling Operations 13	Conveyor K-1 [Upper Tripper for Unit 3]	Baghouse, Partial Enclosure	C13B	14
			3	Coal Handling Operations 13	Conveyor K [Lower Tripper for Unit 3]	Baghouse, Partial Enclosure	C13C	15
16 (13)	EQPT001	16	1	Coal Crushing	Four Crushers and Crusher House	Enclosure/Wet Scrubber	C16	16
21 (16)	EQPT002	21	1	Dry Fly Ash Handling	Dry Fly Ash Collection and Silo	PJFF	C21	21
23 (09)	COMB004	23	1	Combustion Turbine Unit 9	Fuel: Distillate Oil	CT9 Water Injection	C23	23
			2		Fuel: Natural Gas			
24 (10)	COMB005	24	1	Combustion Turbine Unit 10	Fuel: Distillate Oil	CT10 Water Injection	C24	24
			2		Fuel: Natural Gas			
25 (08)	COMB006	25	1	Combustion Turbine Unit 8	Fuel: Distillate Oil	CT8 Water Injection	C25	25
			2		Fuel: Natural Gas			
26 (11)	COMB007	26	1	Combustion Turbine Unit 11	Fuel: Distillate Oil	CT11 Water Injection	C26	26
			2		Fuel: Natural Gas			
27 (06)	COMB008	27	1	Combustion Turbine Unit 6	Fuel: Distillate Oil	CT6 Water Injection	C27	27
			2		Fuel: Natural Gas			
28 (07)	COMB009	28	1	Combustion Turbine Unit 7	Fuel: Distillate Oil	CT7 Water Injection	C28	28
			2		Fuel: Natural Gas			
29 (05)	COMB010	29	1	Combustion Turbine Unit 5	Fuel: Natural Gas	CT5 Water Injection	C29	29
(Note a)		30	1	Limestone Truck Dump Station #1		Fabric Filter	C30	30
		31	1	Limestone Truck Dump Station #2		Fabric Filter	C31	31
		32	1	Limestone Stacking Tube		Fabric Filter	C32	32
		33	1	Limestone Reclaim Conveyor #1		Fabric Filter	C33	33
		34	1	Limestone Reclaim Conveyor #2		Fabric Filter	C34	34
(Note b)		35	1	Road Fugitives from Truck Traffic on Unpaved and Paved Roads				Fugitive
(Note c)		36	1	Unit 1 Cooling Tower with Drift Eliminators				36
		37	1	Unit 2 Cooling Tower with Drift Eliminators				37
		38	1	Unit 3 Cooling Tower with Drift Eliminators				38
(Note d)		39	1	Dix Dam Crest Gate Emergency Generator				39
		40	1	Dix Dam Station Emergency Generator				40
		41	1	CT5 Emergency Generator				41
		42	1	CT6 Emergency Generator				42
		43	1	CT7 Emergency Generator				43
		44	1	CT Area Emergency Fire Pump Engine				44
		45	1	Emergency Steam Plant Fire Pump Engine #1				45
		46	1	Emergency Steam Plant Fire Pump Engine #2				46
		47	1	Emergency Quench Water Pump Engine #1				47
		48	1	Emergency Quench Water Pump Engine #2				48
(Note e)		49	1	Emergency Tier II 752 HP Diesel RICE				49
		50	6	New Ash/Gypsum Landfill and Haul Trucks				50
		51	1	Emergency Tier II 1220 HP Diesel RICE				51
		52	1	Emergency Tier II 1220 HP Diesel RICE				52

a. The Limestone Handling System emission units were part of the FGD system andwere covered by a March 2005 minor revision application.
b. Road fugitives were previously regulated as an insignificant activity. Consistent with correspondence to KDAQ on 5/22/2008, the designation was changed in the 2009 permit application
c. The Cooling Towers were previously regulated as insignificant activities. Consistent with correspondence to KDAQ on 5/22/2008, the designation was changed in the 2009 application.
d. The emergency generators and fire pump engines were previously regulated as insignificant activities. The designation was changed in the 2009 application.

5. Unit 1 Indirect Heat Exchanger (KyEIS ID# 01)

> Documentation of boiler fuel firing rates, emission factors, and emission calculations are provided in this section.

5.1 Description and Nomenclature

Generating Unit 1; Pulverized coal-fired, dry bottom, wall-fired unit with Low NOX Burners, ESP, and FGD. FGD operational in 2010.

Type of Unit (Make, Model):	Babcock & Wilcox Pulverized Coal Boiler
Construction Date:	5/1/1957
Title V Permit ID:	01 (01)
KyEIS Equipment ID:	COMB001
KyEIS Source ID:	01
KyEIS Process ID:	1
Emission Point ID:	17

5.2 Boiler Capacity and Fuel Firing Rates

Boiler Heat Input Capacity	1,260	MMBtu/hr	
Net Power Output	102	MW	

5.21 Coal Properties

Coal Heating Value	22.0	MMBtu/ton	
	11,000	Btu/lb	= (22 MMBtu/ton * 1E6 Btu/MMBtu / 2000 lb/ton)
Coal % Sulfur Content (Weight Basis)	3.8%		(Expected range: 0.2 to 3.8%)
Coal % Ash Content (Weight Basis)	13.8%		(Expected range: 5 to 30%)

5.22 Maximum Coal Firing Rate

Maximum Coal Firing Rate	57.3	ton/hr	= (1260 MMBtu/hr / 22 MMBtu/ton)

5.3 Source Classification Code

SCC:	10100202
SCC Description:	Pulverized Coal: Dry Bottom (Bituminous Coal) (1-01-002-02)
SCC Units:	Tons Bituminous Coal Burned

5.4 Documentation of Emission Factors Used

> Emission factors for the primary pollutants are either those published in AP42 Section 1.1 (9/98 Edition) or from vendor data, as listed below. Control efficiencies listed are based on a combination of vendor information and engineering judgment.

5.41 Primary Pollutants			Emission Factor Basis
CO	0.5	lb/ton	AP42 1.1-3, 9/98
	0.023	lb/MMBtu	= (0.5 lb/ton / 22 MMBtu/ton)
NOX			
Uncontrolled Factor	22	lb/ton	AP42 1.1-3, 9/98; PC, dry bottom, wall-fired, pre-NSPS
	1.000	lb/MMBtu	= (22 lb/ton / 22 MMBtu/ton)
Control Efficiency, LNB	50%		
Controlled Factor	11	lb/ton	
Actual Estimated NOX Emissions	0.500	lb/MMBtu	= (11 lb/ton / 22 MMBtu/ton)
SO2			
Uncontrolled Factor	38	S lb/ton	AP42 1.1-3, 9/98
	144.4	lb/ton	= (38 * 0.038 * 100)
	6.564	lb/MMBtu	= (144.4 lb/ton / 22 MMBtu/ton)
Control Efficiency, FGD	98.6%		Lowest actuals between 2013 and 2014
Controlled Factor	2.0216	lb/ton	= (1-0.99) * 144.4 lb/ton
Actual Estimated SO2 Emissions	0.092	lb/MMBtu	= (2.0216 lb/ton / 22 MMBtu/ton)
Permitted allowable SO2 (61:015)	5.15	lb/MMBtu	
VOC (TNMOC)	0.06	lb/ton	AP42 1.1-19, 9/98
	0.0027	lb/MMBtu	= (0.06 lb/ton / 22 MMBtu/ton)
Methane (Exempted VOC)	0.04	lb/ton	AP42 1.1-19, 9/98
	0.0018	lb/MMBtu	= (0.04 lb/ton / 22 MMBtu/ton)
PM			
Uncontrolled Factor	10	A lb/ton	AP42 1.1-4, 9/98
	138	lb/ton	= (10 * 0.138 * 100)
	6.273	lb/MMBtu	= (138 lb/ton / 22 MMBtu/ton)
Control Efficiency, ESP	98.5%		
Controlled Factor	2.07	lb/ton	= (1-0.985) * 138 lb/ton
Actual Estimated PM Emissions	0.094	lb/MMBtu	= (2.07 lb/ton / 22 MMBtu/ton)
Permitted allowable PM (Reg 7)	0.254	lb/MMBtu	
PM10			
Uncontrolled Factor	2.3	A lb/ton	AP42 1.1-4, 9/98
	31.74	lb/ton	= (2.3 * 0.138 * 100)
	1.443	lb/MMBtu	= (31.74 lb/ton / 22 MMBtu/ton)
Control Efficiency, ESP	98.5%		Assume control efficiency is the same as for PM
Controlled Factor	0.4761	lb/ton	= (1-0.985) * 31.74 lb/ton
	0.022	lb/MMBtu	= (0.476 lb/ton / 22 MMBtu/ton)

PM2.5

Uncontrolled Factor	0.6	A lb/ton	AP42 1.1-6, 9/98
	8.28	lb/ton	= (0.6 * 0.138 * 100)
	0.376	lb/MMBtu	= (8.28 lb/ton / 22 MMBtu/ton)
Percentage of PM10 that is PM2.5	44.44%		Ratio of PM2.5 to PM10 in AP42 1.1-6 is 0.024A / 0.054A = 44.44%.
Controlled Factor	0.212	lb/ton	= (0.4444 * 0.476 lb/ton)
	0.010	lb/MMBtu	= (0.4444 * 0.022 lb/MMBtu)
Back-Calculated Control Efficiency	97.44%		= 1 - 0.01/0.376

5.42 Sulfuric Acid Mist

> H2SO4 emissions are conservatively estimated assuming 1% conversion of S to SO3 in the boiler, 10% reduction of SO3 in the air heater, 10% reduction in the dry ESP, and 50% reduction in the FGD system.

H2SO4

Sulfur loading	76	lb/ton	= 0.038 lb S/lb coal * 2000 lb/ton
Conversion to SO3 in boiler	1%		
Reduction of SO3 in air heater	10%		
Uncontrolled H2SO4 emission factor	2.092	lb/ton	= [76 * 0.01 * (1-0.1) * 98.07848 / 32.065]
Reduction of SO3 in dry ESP	10%		
Reduction of SO3 in FGD system	50%		Vendor guarantee. Actual control may be higher.
Controlled H2SO4 emission factor	0.941	lb/ton	= [76 * 0.01 * (1-0.1) * (1-0.1) * (1-0.5) * 98.07848 / 32.065]
	0.043	lb/MMBtu	= (0.941 lb/ton / 22 MMBtu/ton)
H2SO4 control efficiency downstream of air heater	55%		= 1 - 0.9415 / 2.0922

5.43 Metal Compounds With Factors Based on Coal Concentration

> Emission factors for all metal compounds except mercury and selenium are based on AP42 Table 1.1-16 (9/98 Edition). Emissions in AP42 1.1-16 are expressed as a function of coal concentration, ash content, and either the PM uncontrolled or controlled emission factor.

> Coal metal concentrations are based on either information in the PISCES database for coal samples from Kentucky and West Virginia or on target specifications for coal to be burned in Units 1, 2, and 3 following installation of the FGD system.

Uncontrolled Metal Emission Factors:

Metal Compound	Emission Equation (lb/TBtu)	Coal Conc. (ppmwt)	Ash Content (%)	Total PM Uncontrolled Factor (lb/MMBtu)	Uncontrolled Metal Factor (lb/TBtu)	Equivalent Uncontrolled Metal Factor (lb/ton)
Antimony	0.92*(C/A*PM)^0.63	1	13.8%	6.273	10.187	2.24E-04
Arsenic	3.1*(C/A*PM)^0.85	10	13.8%	6.273	562.733	1.24E-02
Beryllium	1.2*(C/A*PM)^1.1	1.38	13.8%	6.273	113.863	2.50E-03
Cadmium	3.3*(C/A*PM)^0.5	1	13.8%	6.273	22.249	4.89E-04
Chromium	3.7*(C/A*PM)^0.58	19.92	13.8%	6.273	191.948	4.22E-03
Cobalt	1.7*(C/A*PM)^0.69	7.28	13.8%	6.273	93.121	2.05E-03
Lead	3.4*(C/A*PM)^0.8	10	13.8%	6.273	454.507	1.00E-02
Manganese	3.8*(C/A*PM)^0.6	29.76	13.8%	6.273	287.415	6.32E-03
Nickel	4.4*(C/A*PM)^0.48	15	13.8%	6.273	100.836	2.22E-03

Controlled Metal Emission Factors:

Metal Compound	Emission Equation (lb/TBtu)	Coal Conc. (ppmwt)	Ash Content (%)	Total PM Controlled Factor (lb/MMBtu)	Controlled Metal Factor (lb/TBtu)	Equivalent Controlled Metal Factor (lb/ton)	Metal Control Efficiency (%)
Antimony	0.92*(C/A*PM)^0.63	1	13.8%	0.094	0.723	1.59E-05	92.9%
Arsenic	3.1*(C/A*PM)^0.85	10	13.8%	0.094	15.848	3.49E-04	97.2%
Beryllium	1.2*(C/A*PM)^1.1	1.38	13.8%	0.094	1.122	2.47E-05	99.0%
Cadmium	3.3*(C/A*PM)^0.5	1	13.8%	0.094	2.725	5.99E-05	87.8%
Chromium	3.7*(C/A*PM)^0.58	19.92	13.8%	0.094	16.800	3.70E-04	91.2%
Cobalt	1.7*(C/A*PM)^0.69	7.28	13.8%	0.094	5.135	1.13E-04	94.5%
Lead	3.4*(C/A*PM)^0.8	10	13.8%	0.094	15.791	3.47E-04	96.5%
Manganese	3.8*(C/A*PM)^0.6	29.76	13.8%	0.094	23.129	5.09E-04	92.0%
Nickel	4.4*(C/A*PM)^0.48	15	13.8%	0.094	13.432	2.96E-04	86.7%

5.44 Metal Compounds with Emissions Based on AP-42 Controlled Factors

> AP42 provides no concentration-based factor for mercury or selenium. However, AP42 Table 1.1-18 (9/98 Edition) provides controlled emission factors for these metals which are thus used.

> Estimated uncontrolled emission factors are back-calculated based on the metal concentration in the coal.

Mercury

Controlled emission factor	8.3E-05	lb/ton	AP42 1.1-18, 9/98
	3.773	lb/TBtu	= (0.000083 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/TBtu)
Concentration of mercury in coal	0.12	mg/kg	Target specifications for Brown Station coal
Uncontrolled mercury emissions	0.0002	lb/ton	= 0.12 lb Hg /1E6 lb coal * 2000 lb/ton
Assumed control efficiency	65.4%		= (1- 0.000083 / 0.00024)

Selenium

Controlled emission factor	0.0013	lb/ton	AP42 1.1-18, 9/98
	59.091	lb/TBtu	= (0.0013 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/TBtu)
Concentration of selenium in coal	2	mg/kg	Target specifications for Brown Station coal
Uncontrolled selenium emissions	0.004	lb/ton	= 2 lb Se /1E6 lb coal * 2000 lb/ton
Assumed control efficiency	67.5%		= (1- 0.0013 / 0.004)

5.45 Polynuclear Aromatic Hydrocarbons

> Emission factors for select polynuclear aromatic hydrocarbons are taken from AP42 Table 1.1-13 (9/98 Edition). The AP42 factors are controlled emission factors. For purposes of completing the 7007N form, no control efficiency is assigned.

PAH Compound	Emission Factor (lb/ton)	Equivalent Factor (lb/TBtu)	Sample Calculation
Biphenyl	1.70E-06	0.077	= (0.0000017 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/Tbtu)
Naphthalene	1.30E-05	0.591	= (0.000013 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/Tbtu)

5.46 Other Organic Compounds

> Emission factors for other organic compounds expected to be emitted are based on emission factors in EPRI's PISCES database where available, or AP42 Table 1.1-14 (9/98 Edition).

> PISCES (Power Plant Integrated System: Chemical Emissions Study) is data published by the Electric Power Research Institute.

	Emission Factor (lb/ton)	Emission Factor (lb/TBtu)	Emission Factor Basis
Acetaldehyde	7.0E-05	3.2	PISCES
Acetophenone	2.6E-05	1.2	PISCES
Acrolein	4.2E-05	1.9	PISCES
Benzene	8.6E-05	3.9	PISCES
Benzyl chloride	6.2E-06	0.28	PISCES
Bis(2-ethylhexyl)phthalate	7.9E-05	3.6	PISCES
Bromoform	3.9E-05	1.8	AP42 1.1-14, 9/98
Carbon disulfide	2.4E-05	1.1	PISCES
2-Chloroacetophenone	7.0E-06	0.3	AP42 1.1-14, 9/98
Chlorobenzene	3.5E-06	0.16	PISCES
Chloroform	1.8E-05	0.8	PISCES
Cumene	5.3E-06	0.2	AP42 1.1-14, 9/98
Cyanide	2.5E-03	113.6	AP42 1.1-14, 9/98
Dimethyl sulfate	4.8E-05	2.2	AP42 1.1-14, 9/98
2,4-Dinitrotoluene	4.4E-06	0.2	PISCES
Ethylbenzene	1.8E-05	0.8	PISCES
Ethyl chloride	4.2E-05	1.9	AP42 1.1-14, 9/98
Ethylene dibromide	1.2E-06	0.1	AP42 1.1-14, 9/98
Ethylene dichloride	4.0E-05	1.8	AP42 1.1-14, 9/98
Formaldehyde	5.7E-05	2.6	PISCES
Hexane	6.7E-05	3.0	AP42 1.1-14, 9/98
Isophorone	2.6E-05	1.2	PISCES
Methyl bromide	1.6E-04	7.3	AP42 1.1-14, 9/98
Methyl chloride	5.3E-04	24.1	AP42 1.1-14, 9/98
Methyl ethyl ketone	3.9E-04	17.7	AP42 1.1-14, 9/98
Methyl hydrazine	1.7E-04	7.7	AP42 1.1-14, 9/98
Methyl methacrylate	2.0E-05	0.9	AP42 1.1-14, 9/98
Methyl tert butyl ether	3.5E-05	1.6	AP42 1.1-14, 9/98
Methylene chloride	7.9E-05	3.6	PISCES
Phenol	7.3E-05	3.3	PISCES
Propionaldehyde	4.2E-05	1.9	PISCES
Styrene	1.5E-05	0.7	PISCES
Tetrachloroethylene	9.2E-06	0.42	PISCES
Toluene	3.7E-05	1.7	PISCES
1,1,1-Trichloroethane	2.0E-05	0.9	AP42 1.1-14, 9/98
Vinyl acetate	6.8E-06	0.31	PISCES
m/p-Xylene	1.8E-05	0.82	PISCES
o-Xylene	9.7E-06	0.44	PISCES

5.47 Polycyclic Organic Matter (POM)

> Emission factors for POM are taken from AP42 Table 1.1-17 (9/98 Edition). The AP42 factors are uncontrolled emission factors. For purposes of completing the 7007N form, no control efficiency is assigned.

Controlled emission factor	2.08	lb/TBtu	AP42 1.1-17, 9/98 (PC, Dry Bottom)
	4.58E-05	lb/ton	= (2.08 lb/TBtu / 1E6 MMBtu/TBtu * 22 MMBtu/ton)

5.48 Inorganic HAPs- HCl and HF

> Emissions for HCl and HF are based on emission factors published in EPRI's PISCES database.
> The uncontrolled emission factors for HCl and HF are back-calculated based on the chloride and fluoride present in the coal.

Hydrogen Chloride

Controlled emission factor	12,535	lb/TBtu	PISCES
	0.276	lb/ton	= (12535 lb/TBtu / 1E6 MMBtu/TBtu * 22 MMBtu/ton)
Concentration of chloride in coal	700	mg/kg	Target specifications for Brown Station coal
Molecular weight of chlorine	35.453	lb/lbmole	
Molecular weight of HCl	36.461	lb/lbmole	
Uncontrolled HCl emissions	1.440	lb/ton	= 700 lb Cl /1E6 lb coal * 36.46/35.45 * 2000 lb/ton
Back calculated control efficiency	80.8%		= 1 - 0.276/1.44

Hydrogen Fluoride

Controlled emission factor	1,003	lb/TBtu	PISCES
	0.022	lb/ton	= (1003 lb/TBtu / 1E6 MMBtu/TBtu * MMBtu/ton)
Concentration of fluoride in coal	80	mg/kg	Target specifications for Brown Station coal
Molecular weight of fluorine	18.998	lb/lbmole	
Molecular weight of HF	20.006	lb/lbmole	
Uncontrolled HF emissions	0.168	lb/ton	= 80 lb Cl /1E6 lb coal * 20/19 * 2000 lb/ton
Back calculated control efficiency	86.9%		= 1 - 0.022/0.168

5.5 Emission Calculations Based on Factors Documented

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/ton)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Primary Pollutants							
CO	0.5	AP42 1.1-3, 9/98	28.6	125	na	na	na
NOX	22	AP42 1.1-3, 9/98	1,260	5,519	50.0%	630	2,759
SO2	144.4	AP42 1.1-3, 9/98	8,270	36,223	98.6%	116	507
VOC (TNMOC)	0.06	AP42 1.1-19, 9/98	3.4	15.1	na	na	na
Methane (Exempted VOC)	0.04	AP42 1.1-19, 9/98	2.3	10.0	na	na	na
PM	138	AP42 1.1-4, 9/98	7,904	34,618	98.5%	119	519
PM10	31.74	AP42 1.1-4, 9/98	1,818	7,962	98.5%	27	119
PM2.5	8.28	AP42 1.1-6, 9/98	474	2,077	97.4%	12	53
H2SO4	2.09	1% conversion to SO3	120	525	55.0%	54	236
CO_2E	4,561	40 CFR 98 Subpart C	261,201	1,144,061	na	na	na
Metals							
Antimony	2.24E-04	AP42 1.1-16, 9/98	0.0128	0.0562	92.9%	9.11E-04	3.99E-03
Arsenic	1.24E-02	AP42 1.1-16, 9/98	0.7090	3.1056	97.2%	2.00E-02	8.75E-02
Beryllium	2.50E-03	AP42 1.1-16, 9/98	0.1435	0.6284	99.0%	1.41E-03	6.19E-03
Cadmium	4.89E-04	AP42 1.1-16, 9/98	0.0280	0.1228	87.8%	3.43E-03	1.50E-02
Chromium	4.22E-03	AP42 1.1-16, 9/98	0.2419	1.0593	91.2%	2.12E-02	9.27E-02
Cobalt	2.05E-03	AP42 1.1-16, 9/98	0.1173	0.5139	94.5%	6.47E-03	2.83E-02
Lead	1.00E-02	AP42 1.1-16, 9/98	0.5727	2.5083	96.5%	1.99E-02	8.71E-02
Manganese	6.32E-03	AP42 1.1-16, 9/98	0.3621	1.5862	92.0%	2.91E-02	1.28E-01
Nickel	2.22E-03	AP42 1.1-16, 9/98	0.1271	0.5565	86.7%	1.69E-02	7.41E-02
Mercury	0.00024	AP42 1.1-18, 9/98	0.0137	0.0602	65.4%	4.75E-03	2.08E-02
Selenium	0.004	AP42 1.1-18, 9/98	0.2291	1.0034	67.5%	7.45E-02	3.26E-01
PAH Compounds							
Biphenyl	1.70E-06	AP42 1.1-13, 9/98	0.0001	0.0004	na	na	na
Naphthalene	1.30E-05	AP42 1.1-13, 9/98	0.0007	0.0033	na	na	na

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/ton)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Other Organic Compounds							
Acetaldehyde	7.0E-05	PISCES	0.0040	0.0177	na	na	na
Acetophenone	2.6E-05	PISCES	0.0015	0.0066	na	na	na
Acrolein	4.2E-05	PISCES	0.0024	0.0105	na	na	na
Benzene	8.6E-05	PISCES	0.0049	0.0215	na	na	na
Benzyl chloride	6.2E-06	PISCES	0.0004	0.0015	na	na	na
Bis(2-ethylhexyl)phthalate	7.9E-05	PISCES	0.0045	0.0199	na	na	na
Bromoform	3.9E-05	AP42 1.1-14, 9/98	0.0022	0.0098	na	na	na
Carbon disulfide	2.4E-05	PISCES	0.0014	0.0061	na	na	na
2-Chloroacetophenone	7.0E-06	AP42 1.1-14, 9/98	0.0004	0.0018	na	na	na
Chlorobenzene	3.5E-06	PISCES	0.0002	0.0009	na	na	na
Chloroform	1.8E-05	PISCES	0.0010	0.0044	na	na	na
Cumene	5.3E-06	AP42 1.1-14, 9/98	0.0003	0.0013	na	na	na
Cyanide	2.5E-03	AP42 1.1-14, 9/98	0.1432	0.6271	na	na	na
Dimethyl sulfate	4.8E-05	AP42 1.1-14, 9/98	0.0027	0.0120	na	na	na
2,4-Dinitrotoluene	4.4E-06	PISCES	0.0003	0.0011	na	na	na
Ethylbenzene	1.8E-05	PISCES	0.0010	0.0044	na	na	na
Ethyl chloride	4.2E-05	AP42 1.1-14, 9/98	0.0024	0.0105	na	na	na
Ethylene dibromide	1.2E-06	AP42 1.1-14, 9/98	0.0001	0.0003	na	na	na
Ethylene dichloride	4.0E-05	AP42 1.1-14, 9/98	0.0023	0.0100	na	na	na
Formaldehyde	5.7E-05	PISCES	0.0033	0.0143	na	na	na
Hexane	6.7E-05	AP42 1.1-14, 9/98	0.0038	0.0168	na	na	na
Isophorone	2.6E-05	PISCES	0.0015	0.0066	na	na	na
Methyl bromide	1.6E-04	AP42 1.1-14, 9/98	0.0092	0.0401	na	na	na
Methyl chloride	5.3E-04	AP42 1.1-14, 9/98	0.0304	0.1330	na	na	na
Methyl ethyl ketone	3.9E-04	AP42 1.1-14, 9/98	0.0223	0.0978	na	na	na
Methyl hydrazine	1.7E-04	AP42 1.1-14, 9/98	0.0097	0.0426	na	na	na
Methyl methacrylate	2.0E-05	AP42 1.1-14, 9/98	0.0011	0.0050	na	na	na
Methyl tert butyl ether	3.5E-05	AP42 1.1-14, 9/98	0.0020	0.0088	na	na	na
Methylene chloride	7.9E-05	PISCES	0.0045	0.0199	na	na	na
Phenol	7.3E-05	PISCES	0.0042	0.0182	na	na	na
Propionaldehyde	4.2E-05	PISCES	0.0024	0.0105	na	na	na
Styrene	1.5E-05	PISCES	0.0009	0.0039	na	na	na
Tetrachloroethylene	9.2E-06	PISCES	0.0005	0.0023	na	na	na
Toluene	3.7E-05	PISCES	0.0021	0.0094	na	na	na
1,1,1-Trichloroethane	2.0E-05	AP42 1.1-14, 9/98	0.0011	0.0050	na	na	na
Vinyl acetate	6.8E-06	PISCES	0.0004	0.0017	na	na	na
m/p-Xylene	1.8E-05	PISCES	0.0010	0.0045	na	na	na
o-Xylene	9.7E-06	PISCES	0.0006	0.0024	na	na	na
POM	4.6E-05	AP42 1.1-17, 9/98	0.0026	0.0115	na	na	na
Inorganic HAPs- HCl and HF							
Hydrogen Chloride	1.440	PISCES	82.5	361	80.8%	15.8	69.2
Hydrogen Fluoride	0.168	PISCES	9.6	42	86.9%	1.3	5.5

6. Unit 2 Indirect Heat Exchanger (KyEIS ID# 02)

> Documentation of boiler fuel firing rates, emission factors, and emission calculations are provided in this section.

6.1 Description and Nomenclature

Generating Unit 2; Pulverized coal-fired, dry bottom, tangentially-fired unit with Low NOX Burners, ESP, and FGD. FGD began operational in 2010. Emission calculations shown reflect presence of the FGD system.

Type of Unit (Make, Model):	Combustion Engineering Pulverized Coal Boiler
Construction Date:	6/1/1963
Title V Permit ID:	02 (02)
KyEIS Equipment ID:	COMB002
KyEIS Source ID:	02
KyEIS Process ID:	1
Emission Point ID:	17

6.2 Boiler Capacity and Fuel Firing Rates

Boiler Heat Input Capacity	1,733	MMBtu/hr	
Net Power Output	169	MW	

6.21 Coal Properties

Coal Heating Value	22.0	MMBtu/ton	
	11,000	Btu/lb	= (22 MMBtu/ton * 1E6 Btu/MMBtu / 2000 lb/ton)
Coal % Sulfur Content (Weight Basis)	3.8%		(Expected range: 0.2 to 3.8%)
Coal % Ash Content (Weight Basis)	13.8%		(Expected range: 5 to 30%)

6.22 Maximum Coal Firing Rate

Maximum Coal Firing Rate	78.8	ton/hr	= (1733 MMBtu/hr / 22 MMBtu/ton)

6.3 Source Classification Code

SCC:	10100212
SCC Description:	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal) (1-01-002-12)
SCC Units:	Tons Bituminous Coal Burned

6.4 Documentation of Emission Factors Used

> Emission factors for the primary pollutants are either those published in AP42 Section 1.1 (9/98 Edition) or from vendor data, as listed below. Control efficiencies listed are based on a combination of vendor information and engineering judgment.

6.41 Primary Pollutants

				Emission Factor Basis
CO		0.5	lb/ton	AP42 1.1-3, 9/98
		0.023	lb/MMBtu	= (0.5 lb/ton / 22 MMBtu/ton)
NOX				
	Uncontrolled Factor	15	lb/ton	AP42 1.1-3, 9/98; PC, dry bottom, tangentially-fired, pre-NSPS
		0.682	lb/MMBtu	= (15 lb/ton / 22 MMBtu/ton)
	Control Efficiency, LNB	35%		Vendor guarantee
	Controlled Factor	9.75	lb/ton	
	Actual Estimated NOX Emissions	0.443	lb/MMBtu	= (9.75 lb/ton / 22 MMBtu/ton)
SO2				
	Uncontrolled Factor	38	S lb/ton	AP42 1.1-3, 9/98
		144.4	lb/ton	= (38 * 0.038 * 100)
		6.564	lb/MMBtu	= (144.4 lb/ton / 22 MMBtu/ton)
	Control Efficiency, FGD	95%		Lowest actuals between 2013 and 2014
	Controlled Factor	7.3644	lb/ton	= (1-0.95) * 144.4 lb/ton
	Actual Estimated SO2 Emissions	0.335	lb/MMBtu	= (7.36440000000001 lb/ton / 22 MMBtu/ton)
	Permitted allowable SO2 (61:015)	5.15	lb/MMBtu	

During circumstances when Unit 2 exhausts out the existing Unit 2/Unit 3 combined stack (no FGD), coal with a sufficiently low sulfur content to meet the 5.15 lb/MMBtu allowable will be combusted. The maximum coal sulfur content under this configuration will be as follows:

	Max sulfur content, FGD by-pass:	2.98	% sulfur	= (5.15 lb/MMBtu * 22 MMBtu/ton / 38 S lb/ton
VOC (TNMOC)		0.06	lb/ton	AP42 1.1-19, 9/98
		0.0027	lb/MMBtu	= (0.06 lb/ton / 22 MMBtu/ton)
Methane (Exempted VOC)		0.04	lb/ton	AP42 1.1-19, 9/98
		0.0018	lb/MMBtu	= (0.04 lb/ton / 22 MMBtu/ton)
PM				
	Uncontrolled Factor	10	A lb/ton	AP42 1.1-4, 9/98
		138	lb/ton	= (10 * 0.138 * 100)
		6.273	lb/MMBtu	= (138 lb/ton / 22 MMBtu/ton)
	Control Efficiency, ESP	99.0%		
	Controlled Factor	1.38	lb/ton	= (1-0.99) * 138 lb/ton
	Actual Estimated PM Emissions	0.063	lb/MMBtu	= (1.38 lb/ton / 22 MMBtu/ton)
	Permitted allowable PM (61:015)	0.162	lb/MMBtu	
PM10				
	Uncontrolled Factor	2.3	A lb/ton	AP42 1.1-4, 9/98
		31.74	lb/ton	= (2.3 * 0.138 * 100)
		1.443	lb/MMBtu	= (31.74 lb/ton / 22 MMBtu/ton)
	Control Efficiency, ESP	99.0%		Assume control efficiency is the same as for PM
	Controlled Factor	0.3174	lb/ton	= (1-0.99) * 31.74 lb/ton
		0.014	lb/MMBtu	= (0.317 lb/ton / 22 MMBtu/ton)

PM2.5

Uncontrolled Factor	0.6	A lb/ton	AP42 1.1-6, 9/98
	8.28	lb/ton	= (0.6 * 0.138 * 100)
	0.376	lb/MMBtu	= (8.28 lb/ton / 22 MMBtu/ton)
Percentage of PM10 that is PM2.5	44.44%		Ratio of PM2.5 to PM10 in AP42 1.1-6 is 0.024A / 0.054A = 44.44%.
Controlled Factor	0.141	lb/ton	= (0.4444 * 0.317 lb/ton)
	0.006	lb/MMBtu	= (0.4444 * 0.014 lb/MMBtu)
Back-Calculated Control Efficiency	98.30%		= 1 - 0.006/0.376

6.42 Sulfuric Acid Mist

> H2SO4 emissions are conservatively estimated assuming 1% conversion of S to SO3 in the boiler, 10% reduction of SO3 in the air heater, 10% reduction in the dry ESP, and 50% reduction in the FGD system.

H2SO4

Sulfur loading	76	lb/ton	= 0.038 lb S/lb coal * 2000 lb/ton
Conversion to SO3 in boiler	1%		
Reduction of SO3 in air heater	10%		
Uncontrolled H2SO4 emission factor	2.0922	lb/ton	= [76 * 0.01 * (1-0.1) * 98.07848 / 32.065]
Reduction of SO3 in dry ESP	10%		
Reduction of SO3 in FGD system	50%		Vendor guarantee. Actual control may be higher.
Controlled H2SO4 emission factor	0.9415	lb/ton	= [76 * 0.01 * (1-0.1) * (1-0.1) * (1-0.5) * 98.07848 / 32.065]
	0.043	lb/MMBtu	= (0.941 lb/ton / 22 MMBtu/ton)
H2SO4 control efficiency downstream of air heater	55%		= 1 - 0.9415 / 2.0922

6.43 Metal Compounds With Factors Based on Coal Concentration

> Emission factors for all metal compounds except mercury and selenium are based on AP42 Table 1.1-16 (9/98 Edition). Emissions in AP42 1.1-16 are expressed as a function of coal concentration, ash content, and either the PM uncontrolled or controlled emission factor.

> Coal metal concentrations are based on either information in the PISCES database for coal samples from Kentucky and West Virginia or on target specifications for coal to be burned in Units 1, 2, and 3 following installation of the FGD system.

Uncontrolled Metal Emission Factors:

Metal Compound	Emission Equation (lb/TBtu)	Coal Conc. (ppmwt)	Ash Content (%)	Total PM Uncontrolled Factor (lb/MMBtu)	Uncontrolled Metal Factor (lb/TBtu)	Equivalent Uncontrolled Metal Factor (lb/ton)
Antimony	0.92*(C/A*PM)^0.63	1	13.8%	6.273	10.187	2.24E-04
Arsenic	3.1*(C/A*PM)^0.85	10	13.8%	6.273	562.733	1.24E-02
Beryllium	1.2*(C/A*PM)^1.1	1.38	13.8%	6.273	113.863	2.50E-03
Cadmium	3.3*(C/A*PM)^0.5	1	13.8%	6.273	22.249	4.89E-04
Chromium	3.7*(C/A*PM)^0.58	19.92	13.8%	6.273	191.948	4.22E-03
Cobalt	1.7*(C/A*PM)^0.69	7.28	13.8%	6.273	93.121	2.05E-03
Lead	3.4*(C/A*PM)^0.8	10	13.8%	6.273	454.507	1.00E-02
Manganese	3.8*(C/A*PM)^0.6	29.76	13.8%	6.273	287.415	6.32E-03
Nickel	4.4*(C/A*PM)^0.48	15	13.8%	6.273	100.836	2.22E-03

Controlled Metal Emission Factors:

Metal Compound	Emission Equation (lb/TBtu)	Coal Conc. (ppmwt)	Ash Content (%)	Total PM Controlled Factor (lb/MMBtu)	Controlled Metal Factor (lb/TBtu)	Equivalent Controlled Metal Factor (lb/ton)	Metal Control Efficiency (%)
Antimony	0.92*(C/A*PM)^0.63	1	13.8%	0.063	0.560	1.23E-05	94.5%
Arsenic	3.1*(C/A*PM)^0.85	10	13.8%	0.063	11.228	2.47E-04	98.0%
Beryllium	1.2*(C/A*PM)^1.1	1.38	13.8%	0.063	0.718	1.58E-05	99.4%
Cadmium	3.3*(C/A*PM)^0.5	1	13.8%	0.063	2.225	4.89E-05	90.0%
Chromium	3.7*(C/A*PM)^0.58	19.92	13.8%	0.063	13.280	2.92E-04	93.1%
Cobalt	1.7*(C/A*PM)^0.69	7.28	13.8%	0.063	3.882	8.54E-05	95.8%
Lead	3.4*(C/A*PM)^0.8	10	13.8%	0.063	11.417	2.51E-04	97.5%
Manganese	3.8*(C/A*PM)^0.6	29.76	13.8%	0.063	18.135	3.99E-04	93.7%
Nickel	4.4*(C/A*PM)^0.48	15	13.8%	0.063	11.056	2.43E-04	89.0%

6.44 Metal Compounds with Emissions Based on AP-42 Controlled Factors

> AP42 provides no concentration-based factor for mercury or selenium. However, AP42 Table 1.1-18 (9/98 Edition) provides controlled emission factors for these metals which are thus used.

> Estimated uncontrolled emission factors are back-calculated based on the metal concentration in the coal.

Mercury

Controlled emission factor	8.3E-05	lb/ton	AP42 1.1-18, 9/98
	3.773	lb/TBtu	= (0.000083 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/TBtu)
Concentration of mercury in coal	0.12	mg/kg	Target specifications for Brown Station coal
Uncontrolled mercury emissions	0.00024	lb/ton	= 0.12 lb Hg /1E6 lb coal * 2000 lb/ton
Assumed control efficiency	65.4%		= (1- 0.000083 / 0.00024)

Selenium

Controlled emission factor	0.0013	lb/ton	AP42 1.1-18, 9/98
	59.091	lb/TBtu	= (0.0013 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/TBtu)
Concentration of selenium in coal	2	mg/kg	Target specifications for Brown Station coal
Uncontrolled selenium emissions	0.004	lb/ton	= 2 lb Se /1E6 lb coal * 2000 lb/ton
Assumed control efficiency	67.5%		= (1- 0.0013 / 0.004)

6.45 Polynuclear Aromatic Hydrocarbons

> Emission factors for select polynuclear aromatic hydrocarbons are taken from AP42 Table 1.1-13 (9/98 Edition). The AP42 factors are controlled emission factors. For purposes of completing the 7007N form, no control efficiency is assigned.

PAH Compound	Emission Factor (lb/ton)	Equivalent Factor (lb/TBtu)	Sample Calculation
Biphenyl	1.70E-06	0.077	= (0.0000017 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/Tbtu)
Naphthalene	1.30E-05	0.591	= (0.000013 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/Tbtu)

6.46 Other Organic Compounds

> Emission factors for other organic compounds expected to be emitted are based on emission factors in EPRI's PISCES database where available, or AP42 Table 1.1-14 (9/98 Edition).

> PISCES (Power Plant Integrated System: Chemical Emissions Study) is data published by the Electric Power Research Institute.

	Emission Factor (lb/ton)	Emission Factor (lb/TBtu)	Emission Factor Basis
Acetaldehyde	7.0E-05	3.2	PISCES
Acetophenone	2.6E-05	1.2	PISCES
Acrolein	4.2E-05	1.9	PISCES
Benzene	8.6E-05	3.9	PISCES
Benzyl chloride	6.2E-06	0.28	PISCES
Bis(2-ethylhexyl)phthalate	7.9E-05	3.6	PISCES
Bromoform	3.9E-05	1.8	AP42 1.1-14, 9/98
Carbon disulfide	2.4E-05	1.1	PISCES
2-Chloroacetophenone	7.0E-06	0.3	AP42 1.1-14, 9/98
Chlorobenzene	3.5E-06	0.16	PISCES
Chloroform	1.8E-05	0.8	PISCES
Cumene	5.3E-06	0.2	AP42 1.1-14, 9/98
Cyanide	2.5E-03	113.6	AP42 1.1-14, 9/98
Dimethyl sulfate	4.8E-05	2.2	AP42 1.1-14, 9/98
2,4-Dinitrotoluene	4.4E-06	0.2	PISCES
Ethylbenzene	1.8E-05	0.8	PISCES
Ethyl chloride	4.2E-05	1.9	AP42 1.1-14, 9/98
Ethylene dibromide	1.2E-06	0.1	AP42 1.1-14, 9/98
Ethylene dichloride	4.0E-05	1.8	AP42 1.1-14, 9/98
Formaldehyde	5.7E-05	2.6	PISCES
Hexane	6.7E-05	3.0	AP42 1.1-14, 9/98
Isophorone	2.6E-05	1.2	PISCES
Methyl bromide	1.6E-04	7.3	AP42 1.1-14, 9/98
Methyl chloride	5.3E-04	24.1	AP42 1.1-14, 9/98
Methyl ethyl ketone	3.9E-04	17.7	AP42 1.1-14, 9/98
Methyl hydrazine	1.7E-04	7.7	AP42 1.1-14, 9/98
Methyl methacrylate	2.0E-05	0.9	AP42 1.1-14, 9/98
Methyl tert butyl ether	3.5E-05	1.6	AP42 1.1-14, 9/98
Methylene chloride	7.9E-05	3.6	PISCES
Phenol	7.3E-05	3.3	PISCES
Propionaldehyde	4.2E-05	1.9	PISCES
Styrene	1.5E-05	0.7	PISCES
Tetrachloroethylene	9.2E-06	0.42	PISCES
Toluene	3.7E-05	1.7	PISCES
1,1,1-Trichloroethane	2.0E-05	0.9	AP42 1.1-14, 9/98
Vinyl acetate	6.8E-06	0.31	PISCES
m/p-Xylene	1.8E-05	0.82	PISCES
o-Xylene	9.7E-06	0.44	PISCES

6.47 Polycyclic Organic Matter (POM)

> Emission factors for POM are taken from AP42 Table 1.1-17 (9/98 Edition). The AP42 factors are uncontrolled emission factors. For purposes of completing the 7007N form, no control efficiency is assigned.

Controlled emission factor	2.4	lb/TBtu	AP42 1.1-17, 9/98 (PC, Dry Bottom, Tangentially Fired)
	5.28E-05	lb/ton	= (2.4 lb/TBtu / 1E6 MMBtu/TBtu * 22 MMBtu/ton)

6.48 Inorganic HAPs- HCl and HF

> Emissions for HCl and HF are based on emission factors published in EPRI's PISCES database.

> The uncontrolled emission factors for HCl and HF are back-calculated based on the chloride and fluoride present in the coal.

Hydrogen Chloride

Controlled emission factor	12,535	lb/TBtu	PISCES
	0.276	lb/ton	= (12535 lb/TBtu / 1E6 MMBtu/TBtu * 22 MMBtu/ton)
Concentration of chloride in coal	700	mg/kg	Target specifications for Brown Station coal
Molecular weight of chlorine	35.453	lb/lbmole	
Molecular weight of HCl	36.461	lb/lbmole	
Uncontrolled HCl emissions	1.440	lb/ton	= 700 lb Cl /1E6 lb coal * 36.46/35.45 * 2000 lb/ton
Back calculated control efficiency	80.8%		= 1 - 0.276/1.44

Hydrogen Fluoride

Controlled emission factor	1,003	lb/TBtu	PISCES
	0.022	lb/ton	= (1003 lb/TBtu / 1E6 MMBtu/TBtu * MMBtu/ton)
Concentration of fluoride in coal	80	mg/kg	Target specifications for Brown Station coal
Molecular weight of fluorine	18.998	lb/lbmole	
Molecular weight of HF	20.006	lb/lbmole	
Uncontrolled HF emissions	0.168	lb/ton	= 80 lb Cl /1E6 lb coal * 20/19 * 2000 lb/ton
Back calculated control efficiency	86.9%		= 1 - 0.022/0.168

6.5 Emission Calculations Based on Factors Documented

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/ton)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Primary Pollutants							
CO	0.5	AP42 1.1-3, 9/98	39.4	173	na	na	na
NOX	15	AP42 1.1-3, 9/98	1,182	5,175	35.0%	768	3,364
SO2	144.4	AP42 1.1-3, 9/98	11,375	49,822	94.9%	580	2,541
VOC (TNMOC)	0.06	AP42 1.1-19, 9/98	4.7	20.7	na	na	na
Methane (Exempted VOC)	0.04	AP42 1.1-19, 9/98	3.2	13.8	na	na	na
PM	138	AP42 1.1-4, 9/98	10,871	47,613	99.0%	109	476
PM10	31.74	AP42 1.1-4, 9/98	2,500	10,951	99.0%	25	110
PM2.5	8.28	AP42 1.1-6, 9/98	652	2,857	98.3%	11	49
H2SO4	2.09	1% conversion to SO3	165	722	55.0%	74	325
CO_2E	4,561	40 CFR 98 Subpart C	359,255	1,573,538	na	na	na
Metals							
Antimony	2.24E-04	AP42 1.1-16, 9/98	0.0177	0.0773	94.5%	9.70E-04	4.25E-03
Arsenic	1.24E-02	AP42 1.1-16, 9/98	0.9752	4.2714	98.0%	1.95E-02	8.52E-02
Beryllium	2.50E-03	AP42 1.1-16, 9/98	0.1973	0.8643	99.4%	1.25E-03	5.45E-03
Cadmium	4.89E-04	AP42 1.1-16, 9/98	0.0386	0.1689	90.0%	3.86E-03	1.69E-02
Chromium	4.22E-03	AP42 1.1-16, 9/98	0.3326	1.4570	93.1%	2.30E-02	1.01E-01
Cobalt	2.05E-03	AP42 1.1-16, 9/98	0.1614	0.7068	95.8%	6.73E-03	2.95E-02
Lead	1.00E-02	AP42 1.1-16, 9/98	0.7877	3.4500	97.5%	1.98E-02	8.67E-02
Manganese	6.32E-03	AP42 1.1-16, 9/98	0.4981	2.1816	93.7%	3.14E-02	1.38E-01
Nickel	2.22E-03	AP42 1.1-16, 9/98	0.1747	0.7654	89.0%	1.92E-02	8.39E-02
Mercury	0.00024	AP42 1.1-18, 9/98	0.0189	0.0828	65.4%	6.54E-03	2.86E-02
Selenium	0.004	AP42 1.1-18, 9/98	0.3151	1.3801	67.5%	1.02E-01	4.49E-01
PAH Compounds							
Biphenyl	1.70E-06	AP42 1.1-13, 9/98	0.0001	0.0006	na	na	na
Naphthalene	1.30E-05	AP42 1.1-13, 9/98	0.0010	0.0045	na	na	na

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/ton)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Other Organic Compounds							
Acetaldehyde	7.0E-05	PISCES	0.0055	0.0243	na	na	na
Acetophenone	2.6E-05	PISCES	0.0021	0.0091	na	na	na
Acrolein	4.2E-05	PISCES	0.0033	0.0144	na	na	na
Benzene	8.6E-05	PISCES	0.0068	0.0296	na	na	na
Benzyl chloride	6.2E-06	PISCES	0.0005	0.0021	na	na	na
Bis(2-ethylhexyl)phthalate	7.9E-05	PISCES	0.0062	0.0273	na	na	na
Bromoform	3.9E-05	AP42 1.1-14, 9/98	0.0031	0.0135	na	na	na
Carbon disulfide	2.4E-05	PISCES	0.0019	0.0083	na	na	na
2-Chloroacetophenone	7.0E-06	AP42 1.1-14, 9/98	0.0006	0.0024	na	na	na
Chlorobenzene	3.5E-06	PISCES	0.0003	0.0012	na	na	na
Chloroform	1.8E-05	PISCES	0.0014	0.0061	na	na	na
Cumene	5.3E-06	AP42 1.1-14, 9/98	0.0004	0.0018	na	na	na
Cyanide	2.5E-03	AP42 1.1-14, 9/98	0.1969	0.8626	na	na	na
Dimethyl sulfate	4.8E-05	AP42 1.1-14, 9/98	0.0038	0.0166	na	na	na
2,4-Dinitrotoluene	4.4E-06	PISCES	0.0003	0.0015	na	na	na
Ethylbenzene	1.8E-05	PISCES	0.0014	0.0061	na	na	na
Ethyl chloride	4.2E-05	AP42 1.1-14, 9/98	0.0033	0.0145	na	na	na
Ethylene dibromide	1.2E-06	AP42 1.1-14, 9/98	0.0001	0.0004	na	na	na
Ethylene dichloride	4.0E-05	AP42 1.1-14, 9/98	0.0032	0.0138	na	na	na
Formaldehyde	5.7E-05	PISCES	0.0045	0.0197	na	na	na
Hexane	6.7E-05	AP42 1.1-14, 9/98	0.0053	0.0231	na	na	na
Isophorone	2.6E-05	PISCES	0.0021	0.0091	na	na	na
Methyl bromide	1.6E-04	AP42 1.1-14, 9/98	0.0126	0.0552	na	na	na
Methyl chloride	5.3E-04	AP42 1.1-14, 9/98	0.0417	0.1829	na	na	na
Methyl ethyl ketone	3.9E-04	AP42 1.1-14, 9/98	0.0307	0.1346	na	na	na
Methyl hydrazine	1.7E-04	AP42 1.1-14, 9/98	0.0134	0.0587	na	na	na
Methyl methacrylate	2.0E-05	AP42 1.1-14, 9/98	0.0016	0.0069	na	na	na
Methyl tert butyl ether	3.5E-05	AP42 1.1-14, 9/98	0.0028	0.0121	na	na	na
Methylene chloride	7.9E-05	PISCES	0.0062	0.0273	na	na	na
Phenol	7.3E-05	PISCES	0.0057	0.0250	na	na	na
Propionaldehyde	4.2E-05	PISCES	0.0033	0.0144	na	na	na
Styrene	1.5E-05	PISCES	0.0012	0.0053	na	na	na
Tetrachloroethylene	9.2E-06	PISCES	0.0007	0.0032	na	na	na
Toluene	3.7E-05	PISCES	0.0029	0.0129	na	na	na
1,1,1-Trichloroethane	2.0E-05	AP42 1.1-14, 9/98	0.0016	0.0069	na	na	na
Vinyl acetate	6.8E-06	PISCES	0.0005	0.0024	na	na	na
m/p-Xylene	1.8E-05	PISCES	0.0014	0.0062	na	na	na
o-Xylene	9.7E-06	PISCES	0.0008	0.0033	na	na	na
POM	5.3E-05	AP42 1.1-17, 9/98	0.0042	0.0182	na	na	na
Inorganic HAPs- HCl and HF							
Hydrogen Chloride	1.440	PISCES	113.4	497	80.8%	21.7	95.1
Hydrogen Fluoride	0.168	PISCES	13.3	58	86.9%	1.7	7.6

7. Unit 3 Indirect Heat Exchanger (KyEIS ID# 03)

> Documentation of boiler fuel firing rates, emission factors, and emission calculations are provided in this section.

7.1 Description and Nomenclature

Generating Unit 3; Tangentially-Fired Utility Boiler with Low NOX Burners, SCR, ESP, and FGD. FGD operational in 2010. SCR operational in December 2012. PJFF operational and replaces ESP prior to Feb. 2016. Emission calculations shown reflect presence of FGD, SCR, PJFF and low NOx burners

Type of Unit (Make, Model):	Combustion Engineering Pulverized Coal Boiler
Construction Date:	7/19/1971
Title V Permit ID:	03 (03)
KyEIS Equipment ID:	COMB003
KyEIS Source ID:	03
KyEIS Process ID:	1
Emission Point ID:	17

7.2 Boiler Capacity and Fuel Firing Rates

Boiler Heat Input Capacity	5,300 MMBtu/hr	
Net Power Output	433 MW	

7.21 Coal Properties

Coal Heating Value	22.0 MMBtu/ton	
	11,000 Btu/lb	= (22 MMBtu/ton * 1E6 Btu/MMBtu / 2000 lb/ton)
Coal % Sulfur Content (Weight Basis)	3.8%	(Expected range: 0.2 to 3.8%)
Coal % Ash Content (Weight Basis)	13.8%	(Expected range: 5 to 30%)

7.22 Maximum Coal Firing Rate

240.9 ton/hr	= (5300 MMBtu/hr / 22 MMBtu/ton)

7.3 Source Classification Code

SCC:	10100212
SCC Description:	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal) (1-01-002-12)
SCC Units:	Tons Bituminous Coal Burned

7.4 Documentation of Emission Factors Used

> Emission factors for the primary pollutants are either those published in AP42 Section 1.1 (9/98 Edition) or from vendor data, as listed below. Control efficiencies listed are based on a combination of vendor information and engineering judgment.

7.41 Primary Pollutants

	Value	Unit	Emission Factor Basis
CO	0.5	lb/ton	AP42 1.1-3, 9/98
	0.023	lb/MMBtu	= (0.5 lb/ton / 22 MMBtu/ton)
NOX			
Uncontrolled Factor	15	lb/ton	AP42 1.1-3, 9/98; PC, dry bottom, tangentially fired, pre-NSPS
	0.682	lb/MMBtu	= (15 lb/ton / 22 MMBtu/ton)
Control Efficiency, LNB	50%		
Control Efficiency, SCR	85%		Vendor guarantee for NOX control in SCR.
Combined Control	92.5%		= 1 - (1 - 0.85) * 0.5
Controlled Factor	1.125	lb/ton	
Actual Estimated NOX Emissions	0.05	lb/MMBtu	= (1.125 lb/ton / 22 MMBtu/ton)
Allowable NOX Emissions	0.07	lb/MMBtu	
SO2			
Uncontrolled Factor	38	S lb/ton	AP42 1.1-3, 9/98
	144.4	lb/ton	= (38 * 0.038 * 100)
	6.564	lb/MMBtu	= (144.4 lb/ton / 22 MMBtu/ton)
Control Efficiency, FGD	98.4%		Lowest actuals between 2013 and 2014
Controlled Factor	2.3104	lb/ton	= (1-0.98) * 144.4 lb/ton
Actual Estimated SO2 Emissions	0.105	lb/MMBtu	= (2.3104 lb/ton / 22 MMBtu/ton)
Allowable SO2 Emissions	0.105	MMBtu	Higher of 0.1 lb/MMBtu OR 97% control
VOC (TNMOC)	0.06	lb/ton	AP42 1.1-19, 9/98
	0.0027	lb/MMBtu	= (0.06 lb/ton / 22 MMBtu/ton)
Methane (Exempted VOC)	0.04	lb/ton	AP42 1.1-19, 9/98
	0.0018	lb/MMBtu	= (0.04 lb/ton / 22 MMBtu/ton)
PM			
Uncontrolled Factor	10	A lb/ton	AP42 1.1-4, 9/98
	138	lb/ton	= (10 * 0.138 * 100)
	6.273	lb/MMBtu	= (138 lb/ton / 22 MMBtu/ton)
Control Efficiency, PJFF	99.52%		Efficiency needed to reach consent decree limit of 0.03 lb/MMBtu.
Controlled Factor	0.66	lb/ton	= (1-0.9952) * 138 lb/ton
Actual Estimated PM Emissions	0.03	lb/MMBtu	= (0.66 lb/ton / 22 MMBtu/ton)
Allowable PM Emissions	0.03	lb/MMBtu	
PM10			
Uncontrolled Factor	2.3	A lb/ton	AP42 1.1-4, 9/98
	31.74	lb/ton	= (2.3 * 0.138 * 100)
	1.443	lb/MMBtu	= (31.74 lb/ton / 22 MMBtu/ton)
Controlled Factor	0.66	lb/ton	Assume maximum PM10 emission rate is same as PM emission rate.
	0.030	lb/MMBtu	
Back-Calculated Control Efficiency	97.92%		= 1 - 0.03/1.443

PM2.5

Uncontrolled Factor	0.6	A lb/ton	AP42 1.1-6, 9/98
	8.28	lb/ton	= (0.6 * 0.138 * 100)
	0.376	lb/MMBtu	= (8.28 lb/ton / 22 MMBtu/ton)
Percentage of PM10 that is PM2.5	44.44%		Ratio of PM2.5 to PM10 in AP42 1.1-6 is 0.024A / 0.054A = 44.44%.
Controlled Factor	0.293	lb/ton	= (0.4444 * 0.66 lb/ton)
	0.013	lb/MMBtu	= (0.4444 * 0.03 lb/MMBtu)
Back-Calculated Control Efficiency	96.46%		= 1 - 0.013/0.376

7.42 Sulfuric Acid Mist

> H2SO4 emissions are conservatively estimated assuming 1% conversion of S to SO3 in the boiler, 2% conversion in the SCR, 10% reduction of SO3 in the air heater, 10% reduction in the dry ESP, 50% reduction in the FGD system, and 70.96% reduction from the SO3 mitigation system.

H2SO4

Sulfur loading	76	lb/ton	= 0.038 lb S/lb coal * 2000 lb/ton
Conversion to SO3 in boiler and generation in SCR	3%		
Reduction of SO3 in air heater	5%		
Uncontrolled H2SO4 emission factor	6.6252	lb/ton	= [76 * 0.03 * (1-0.05) * 98.07848 / 32.065]
Reduction of SO3 in PJFF	5%		
Reduction of SO3 in FGD system	50%		Vendor guarantee. Actual control may be higher.
Reduction from SO3 mitigation system	85.60%		Estimated performance level.
Controlled H2SO4 emission factor	0.4532	lb/ton	= [76*0.03*(1-0.05)*(1-0.05)*(1-0.5)*(1-0.856) * 98.07848 / 32.065]
	0.021	lb/MMBtu	= (0.453 lb/ton / 22 MMBtu/ton)
H2SO4 control efficiency downstream of air heater	93.2%		= 1 - 0.4532 / 6.6252

7.43 Metal Compounds With AP-42 Factors Based on Coal Concentration

> Emission factors for all metal compounds except mercury and selenium are based on AP42 Table 1.1-16 (9/98 Edition). Emissions in AP42 1.1-16 are expressed as a function of coal concentration, ash content, and either the PM uncontrolled or controlled emission factor.

> Coal metal concentrations are based on either information in the PISCES database for coal samples from Kentucky and West Virginia or on target specifications for coal to be burned in Units 1, 2, and 3 following installation of the FGD system.

Uncontrolled Metal Emission Factors:

Metal Compound	Emission Equation (lb/TBtu)	Coal Conc. (ppmwt)	Ash Content (%)	Total PM Uncontrolled Factor (lb/MMBtu)	Uncontrolled Metal Factor (lb/TBtu)	Equivalent Uncontrolled Metal Factor (lb/ton)
Antimony	0.92*(C/A*PM)^0.63	1	13.8%	6.273	10.187	2.24E-04
Arsenic	3.1*(C/A*PM)^0.85	10	13.8%	6.273	562.733	1.24E-02
Beryllium	1.2*(C/A*PM)^1.1	1.38	13.8%	6.273	113.863	2.50E-03
Cadmium	3.3*(C/A*PM)^0.5	1	13.8%	6.273	22.249	4.89E-04
Chromium	3.7*(C/A*PM)^0.58	19.92	13.8%	6.273	191.948	4.22E-03
Cobalt	1.7*(C/A*PM)^0.69	7.28	13.8%	6.273	93.121	2.05E-03
Lead	3.4*(C/A*PM)^0.8	10	13.8%	6.273	454.507	1.00E-02
Manganese	3.8*(C/A*PM)^0.6	29.76	13.8%	6.273	287.415	6.32E-03
Nickel	4.4*(C/A*PM)^0.48	15	13.8%	6.273	100.836	2.22E-03

Controlled Metal Emission Factors:

Metal Compound	Emission Equation (lb/TBtu)	Coal Conc. (ppmwt)	Ash Content (%)	Total PM Controlled Factor (lb/MMBtu)	Controlled Metal Factor (lb/TBtu)	Equivalent Controlled Metal Factor (lb/ton)	Metal Control Efficiency (%)
Antimony	0.92*(C/A*PM)^0.63	1	13.8%	0.030	0.352	7.74E-06	96.5%
Arsenic	3.1*(C/A*PM)^0.85	10	13.8%	0.030	5.998	1.32E-04	98.9%
Beryllium	1.2*(C/A*PM)^1.1	1.38	13.8%	0.030	0.319	7.02E-06	99.7%
Cadmium	3.3*(C/A*PM)^0.5	1	13.8%	0.030	1.539	3.38E-05	93.1%
Chromium	3.7*(C/A*PM)^0.58	19.92	13.8%	0.030	8.657	1.90E-04	95.5%
Cobalt	1.7*(C/A*PM)^0.69	7.28	13.8%	0.030	2.334	5.13E-05	97.5%
Lead	3.4*(C/A*PM)^0.8	10	13.8%	0.030	6.328	1.39E-04	98.6%
Manganese	3.8*(C/A*PM)^0.6	29.76	13.8%	0.030	11.650	2.56E-04	95.9%
Nickel	4.4*(C/A*PM)^0.48	15	13.8%	0.030	7.760	1.71E-04	92.3%

7.44 Metal Compounds with Emissions Based on AP-42 Controlled Factors

> AP42 provides no concentration-based factor for mercury or selenium. However, AP42 Table 1.1-18 (9/98 Edition) provides controlled emission factors for these metals which are thus used.

> Estimated uncontrolled emission factors are back-calculated based on the metal concentration in the coal.

Mercury

Controlled emission factor	2.6E-05	lb/ton	AP42 1.1-18, 9/98 adjusted for PJFF
	1.200	lb/TBtu	= (0.0000264 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/TBtu)
Concentration of mercury in coal	0.12	mg/kg	Target specifications for Brown Station coal
Uncontrolled mercury emissions	0.00024	lb/ton	= 0.12 lb Hg /1E6 lb coal * 2000 lb/ton
Assumed control efficiency	89.0%		= (1- 0.0000264 / 0.00024)

Selenium

Controlled emission factor	0.0013	lb/ton	AP42 1.1-18, 9/98
	59.091	lb/TBtu	= (0.0013 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/TBtu)
Concentration of selenium in coal	2	mg/kg	Target specifications for Brown Station coal
Uncontrolled selenium emissions	0.004	lb/ton	= 2 lb Se /1E6 lb coal * 2000 lb/ton
Assumed control efficiency	67.5%		= (1- 0.0013 / 0.004)

7.45 Polynuclear Aromatic Hydrocarbons

> Emission factors for select polynuclear aromatic hydrocarbons are taken from AP42 Table 1.1-13 (9/98 Edition). The AP42 factors are controlled emission factors. For purposes of completing the 7007N form, no control efficiency is assigned.

PAH Compound	Emission Factor (lb/ton)	Equivalent Factor (lb/TBtu)	Sample Calculation
Biphenyl	1.70E-06	0.077	= (0.0000017 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/Tbtu)
Naphthalene	1.30E-05	0.591	= (0.000013 lb/ton / 22 MMBtu/ton * 1E6 MMBtu/Tbtu)

7.46 Other Organic Compounds

> Emission factors for other organic compounds expected to be emitted are based on emission factors in EPRI's PISCES database where available, or AP42 Table 1.1-14 (9/98 Edition).

> PISCES (Power Plant Integrated System: Chemical Emissions Study) is data published by the Electric Power Research Institute.

	Emission Factor (lb/ton)	Emission Factor (lb/TBtu)	Emission Factor Basis
Acetaldehyde	7.0E-05	3.2	PISCES
Acetophenone	2.6E-05	1.2	PISCES
Acrolein	4.2E-05	1.9	PISCES
Benzene	8.6E-05	3.9	PISCES
Benzyl chloride	6.2E-06	0.28	PISCES
Bis(2-ethylhexyl)phthalate	7.9E-05	3.6	PISCES
Bromoform	3.9E-05	1.8	AP42 1.1-14, 9/98
Carbon disulfide	2.4E-05	1.1	PISCES
2-Chloroacetophenone	7.0E-06	0.3	AP42 1.1-14, 9/98
Chlorobenzene	3.5E-06	0.16	PISCES
Chloroform	1.8E-05	0.8	PISCES
Cumene	5.3E-06	0.2	AP42 1.1-14, 9/98
Cyanide	2.5E-03	113.6	AP42 1.1-14, 9/98
Dimethyl sulfate	4.8E-05	2.2	AP42 1.1-14, 9/98
2,4-Dinitrotoluene	4.4E-06	0.2	PISCES
Ethylbenzene	1.8E-05	0.8	PISCES
Ethyl chloride	4.2E-05	1.9	AP42 1.1-14, 9/98
Ethylene dibromide	1.2E-06	0.1	AP42 1.1-14, 9/98
Ethylene dichloride	4.0E-05	1.8	AP42 1.1-14, 9/98
Formaldehyde	5.7E-05	2.6	PISCES
Hexane	6.7E-05	3.0	AP42 1.1-14, 9/98
Isophorone	2.6E-05	1.2	PISCES
Methyl bromide	1.6E-04	7.3	AP42 1.1-14, 9/98
Methyl chloride	5.3E-04	24.1	AP42 1.1-14, 9/98
Methyl ethyl ketone	3.9E-04	17.7	AP42 1.1-14, 9/98
Methyl hydrazine	1.7E-04	7.7	AP42 1.1-14, 9/98
Methyl methacrylate	2.0E-05	0.9	AP42 1.1-14, 9/98
Methyl tert butyl ether	3.5E-05	1.6	AP42 1.1-14, 9/98
Methylene chloride	7.9E-05	3.6	PISCES
Phenol	7.3E-05	3.3	PISCES
Propionaldehyde	4.2E-05	1.9	PISCES
Styrene	1.5E-05	0.7	PISCES
Tetrachloroethylene	9.2E-06	0.42	PISCES
Toluene	3.7E-05	1.7	PISCES
1,1,1-Trichloroethane	2.0E-05	0.9	AP42 1.1-14, 9/98
Vinyl acetate	6.8E-06	0.31	PISCES
m/p-Xylene	1.8E-05	0.82	PISCES
o-Xylene	9.7E-06	0.44	PISCES

7.47 Polycyclic Organic Matter (POM)

> Emission factors for POM are taken from AP42 Table 1.1-17 (9/98 Edition). The AP42 factors are uncontrolled emission factors. For purposes of completing the 7007N form, no control efficiency is assigned.

Controlled emission factor	2.4	lb/TBtu	AP42 1.1-17, 9/98 (PC, Dry Bottom, Tangentially Fired)
	5.28E-05	lb/ton	= (2.4 lb/TBtu / 1E6 MMBtu/TBtu * 22 MMBtu/ton)

7.48 Inorganic HAPs- HCl and HF

> Emissions for HCl and HF are based on emission factors published in EPRI's PISCES database.

> The uncontrolled emission factors for HCl and HF are back-calculated based on the chloride and fluoride present in the coal.

Hydrogen Chloride

Controlled emission factor	12,535	lb/TBtu	PISCES
	0.276	lb/ton	= (12535 lb/TBtu / 1E6 MMBtu/TBtu * 22 MMBtu/ton)
Concentration of chloride in coal	700	mg/kg	Target specifications for Brown Station coal
Molecular weight of chlorine	35.453	lb/lbmole	
Molecular weight of HCl	36.461	lb/lbmole	
Uncontrolled HCl emissions	1.440	lb/ton	= 700 lb Cl /1E6 lb coal * 36.46/35.45 * 2000 lb/ton
Back calculated control efficiency	80.8%		= 1 - 0.276/1.44

Hydrogen Fluoride

Controlled emission factor	1,003	lb/TBtu	PISCES
	0.022	lb/ton	= (1003 lb/TBtu / 1E6 MMBtu/TBtu * MMBtu/ton)
Concentration of fluoride in coal	80	mg/kg	Target specifications for Brown Station coal
Molecular weight of fluorine	18.998	lb/lbmole	
Molecular weight of HF	20.006	lb/lbmole	
Uncontrolled HF emissions	0.168	lb/ton	= 80 lb Cl /1E6 lb coal * 20/19 * 2000 lb/ton
Back calculated control efficiency	86.9%		= 1 - 0.022/0.168

7.5 Emission Calculations Based on Factors Documented

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/ton)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Primary Pollutants							
CO	0.5	AP42 1.1-3, 9/98	120.5	528	na	na	na
NOX	15	AP42 1.1-3, 9/98	3,614	15,828	92.5%	271	1,187
SO2	144.4	AP42 1.1-3, 9/98	34,787	152,368	98.4%	557	2,438
VOC (TNMOC)	0.06	AP42 1.1-19, 9/98	14.5	63.3	na	na	na
Methane (Exempted VOC)	0.04	AP42 1.1-19, 9/98	9.6	42.2	na	na	na
PM	138	AP42 1.1-4, 9/98	33,245	145,615	99.5%	159	696
PM10	31.74	AP42 1.1-4, 9/98	7,646	33,491	97.9%	159	696
PM2.5	8.28	AP42 1.1-6, 9/98	1,995	8,737	96.5%	71	310
H2SO4	6.63	3% conversion to SO3	1,596	6,991	93.2%	109	478
CO_2E	4,561	40 CFR 98 Subpart C	1,098,703	4,812,320	na	na	na
Metals							
Antimony	2.24E-04	AP42 1.1-16, 9/98	0.0540	0.2365	96.5%	1.86E-03	8.17E-03
Arsenic	1.24E-02	AP42 1.1-16, 9/98	2.9825	13.0633	98.9%	3.18E-02	1.39E-01
Beryllium	2.50E-03	AP42 1.1-16, 9/98	0.6035	2.6432	99.7%	1.69E-03	7.41E-03
Cadmium	4.89E-04	AP42 1.1-16, 9/98	0.1179	0.5165	93.1%	8.15E-03	3.57E-02
Chromium	4.22E-03	AP42 1.1-16, 9/98	1.0173	4.4559	95.5%	4.59E-02	2.01E-01
Cobalt	2.05E-03	AP42 1.1-16, 9/98	0.4935	2.1617	97.5%	1.24E-02	5.42E-02
Lead	1.00E-02	AP42 1.1-16, 9/98	2.4089	10.5509	98.6%	3.35E-02	1.47E-01
Manganese	6.32E-03	AP42 1.1-16, 9/98	1.5233	6.6721	95.9%	6.17E-02	2.70E-01
Nickel	2.22E-03	AP42 1.1-16, 9/98	0.5344	2.3408	92.3%	4.11E-02	1.80E-01
Mercury	0.00024	AP42 1.1-18, 9/98 adjust	0.0578	0.2532	89.0%	6.36E-03	2.79E-02
Selenium	0.004	AP42 1.1-18, 9/98	0.9636	4.2207	67.5%	3.13E-01	1.37E+00
PAH Compounds							
Biphenyl	1.70E-06	AP42 1.1-13, 9/98	0.0004	0.0018	na	na	na
Naphthalene	1.30E-05	AP42 1.1-13, 9/98	0.0031	0.0137	na	na	na

	Uncontrolled Emission Factor (lb/ton)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Other Organic Compounds							
Acetaldehyde	7.0E-05	PISCES	0.0170	0.0743	na	na	na
Acetophenone	2.6E-05	PISCES	0.0064	0.0279	na	na	na
Acrolein	4.2E-05	PISCES	0.0101	0.0441	na	na	na
Benzene	8.6E-05	PISCES	0.0207	0.0905	na	na	na
Benzyl chloride	6.2E-06	PISCES	0.0015	0.0065	na	na	na
Bis(2-ethylhexyl)phthalate	7.9E-05	PISCES	0.0191	0.0836	na	na	na
Bromoform	3.9E-05	AP42 1.1-14, 9/98	0.0094	0.0412	na	na	na
Carbon disulfide	2.4E-05	PISCES	0.0058	0.0255	na	na	na
2-Chloroacetophenone	7.0E-06	AP42 1.1-14, 9/98	0.0017	0.0074	na	na	na
Chlorobenzene	3.5E-06	PISCES	0.0008	0.0037	na	na	na
Chloroform	1.8E-05	PISCES	0.0042	0.0186	na	na	na
Cumene	5.3E-06	AP42 1.1-14, 9/98	0.0013	0.0056	na	na	na
Cyanide	2.5E-03	AP42 1.1-14, 9/98	0.6023	2.6380	na	na	na
Dimethyl sulfate	4.8E-05	AP42 1.1-14, 9/98	0.0116	0.0506	na	na	na
2,4-Dinitrotoluene	4.4E-06	PISCES	0.0011	0.0046	na	na	na
Ethylbenzene	1.8E-05	PISCES	0.0042	0.0186	na	na	na
Ethyl chloride	4.2E-05	AP42 1.1-14, 9/98	0.0101	0.0443	na	na	na
Ethylene dibromide	1.2E-06	AP42 1.1-14, 9/98	0.0003	0.0013	na	na	na
Ethylene dichloride	4.0E-05	AP42 1.1-14, 9/98	0.0096	0.0422	na	na	na
Formaldehyde	5.7E-05	PISCES	0.0138	0.0604	na	na	na
Hexane	6.7E-05	AP42 1.1-14, 9/98	0.0161	0.0707	na	na	na
Isophorone	2.6E-05	PISCES	0.0064	0.0279	na	na	na
Methyl bromide	1.6E-04	AP42 1.1-14, 9/98	0.0385	0.1688	na	na	na
Methyl chloride	5.3E-04	AP42 1.1-14, 9/98	0.1277	0.5592	na	na	na
Methyl ethyl ketone	3.9E-04	AP42 1.1-14, 9/98	0.0940	0.4115	na	na	na
Methyl hydrazine	1.7E-04	AP42 1.1-14, 9/98	0.0410	0.1794	na	na	na
Methyl methacrylate	2.0E-05	AP42 1.1-14, 9/98	0.0048	0.0211	na	na	na
Methyl tert butyl ether	3.5E-05	AP42 1.1-14, 9/98	0.0084	0.0369	na	na	na
Methylene chloride	7.9E-05	PISCES	0.0191	0.0836	na	na	na
Phenol	7.3E-05	PISCES	0.0175	0.0766	na	na	na
Propionaldehyde	4.2E-05	PISCES	0.0101	0.0441	na	na	na
Styrene	1.5E-05	PISCES	0.0037	0.0162	na	na	na
Tetrachloroethylene	9.2E-06	PISCES	0.0022	0.0097	na	na	na
Toluene	3.7E-05	PISCES	0.0090	0.0395	na	na	na
1,1,1-Trichloroethane	2.0E-05	AP42 1.1-14, 9/98	0.0048	0.0211	na	na	na
Vinyl acetate	6.8E-06	PISCES	0.0016	0.0072	na	na	na
m/p-Xylene	1.8E-05	PISCES	0.0043	0.0190	na	na	na
o-Xylene	9.7E-06	PISCES	0.0023	0.0102	na	na	na
POM	5.3E-05	AP42 1.1-17, 9/98	0.0127	0.0557	na	na	na
Inorganic HAPs- HCl and HF							
Hydrogen Chloride	1.440	PISCES	346.9	1,519	80.8%	66.4	291.0
Hydrogen Fluoride	0.168	PISCES	40.6	178	86.9%	5.3	23.3

. Derivation of GHG Emission Factors for Combustion Systems

The basis for GHG emission factors represented on the 7007N form for each type of fuel combustion system are documented in this section.

. GHG Emission Factors for Natural Gas Combustion

Emission factors for GHGs from natural gas combustion are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Tables C-1 and C-2), as revised on 11/29/2013 (78 FR 71909).

The global warming multiplying factors for CH4 and N2O are those specified in Subpart C, as revised on 11/29/2013 (78 FR 71909).

CO2	53.06	kg/MMBtu	40CFR98 Subpart C, Table C-1
	119,316	lb/MMscf	53.06 kg/MMBtu x 2.2046 lb/kg x 1,020 MMBtu/MMscf
CH4	1.00E-03	kg/MMBtu	40CFR98 Subpart C, Table C-2
	2.249	lb/MMscf	1.00E-03 kg/MMBtu x 2.2046 lb/kg x 1,020 MMBtu/MMscf
N2O	1.00E-04	kg/MMBtu	40CFR98 Subpart C, Table C-2
	0.2249	lb/MMscf	1.00E-04 kg/MMBtu x 2.2046 lb/kg x 1,020 MMBtu/MMscf
CO2e			
GWP for CO2	1		40CFR98 Subpart A, Table A-1
GWP for CH4	25		40CFR98 Subpart A, Table A-1
GWP for N2O	298		40CFR98 Subpart A, Table A-1
CO2e Factor:	119,439	lb/MMscf	40CFR98 Subpart A
			119,316 lb/MMscf + (25 x 2.249 lb/MMscf) + (298 x 0.2249 lb/MMscf)

. GHG Emission Factors for Diesel Combustion

Emission factors for GHGs from diesel fuel combustion are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Tables C-1 and C-2), as revised on 11/29/2013 (78 FR 71909).

138

CO2	73.96	kg/MMBtu	40CFR98 Subpart C, Table C-1
	22,501	lb/ Mgal	= 73.96 kg/MMBtu x 2.2046 lb/kg x 138 MMBtu/Mgal
CH4	3.00E-03	kg/MMBtu	40CFR98 Subpart C, Table C-2
	0.9127	lb/ Mgal	= 3.00E-03 kg/MMBtu x 2.2046 lb/kg x 138.0 MMBtu/Mgal
N2O	6.00E-04	kg/MMBtu	40CFR98 Subpart C, Table C-2
	0.1825	lb/ Mgal	= 6.00E-04 kg/MMBtu x 2.2046 lb/kg x 138.0 MMBtu/Mgal
CO2e			
CO2e Factor:	22,578	lb/ Mgal	40CFR98 Subpart A
			= 22,501 lb/Mgal + (25 x 0.913 lb/Mgal) + (298 x 0.183 lb/Mgal)

. **GHC Emission Factors for Coal Combustion**

Emission factors for GHGs from coal fuel combustion are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Tables C-1 and C-2), as revised on 11/29/2013 (78 FR 71909).

CO2	93.28	kg/MMBtu	40CFR98 Subpart C, Table C-1	
	4,524	lb/ ton	93.28 kg/MMBtu x 2.2046 lb/kg x 22 MMBtu/ton	
CH4	1.10E-02	kg/MMBtu	40CFR98 Subpart C, Table C-2	
	0.5335	lb/ ton	1.10E-02 kg/MMBtu x 2.2046 lb/kg x 22 MMBtu/ton	25

N2O	1.60E-03	kg/MMBtu	40CFR98 Subpart C, Table C-2	
	0.0776	lb/ ton	1.60E-03 kg/MMBtu x 2.2046 lb/kg x 22 MMBtu/ton	298
CO2e				
CO2e Factor:	4,561	lb/ ton	40CFR98 Subpart A	
			4,524 lb/ton + (25 x 0.534 lb/ton) + (298 x 0.078 lb/ton)	

GHC Emission Factors for Gasoline Combustion

> Emission factors for GHGs from gasoline combustion are based on Subpart C of EPA's Mandatory Greenhouse Gas Reporting Rule (MRR, 40 CFR 98 Subpart C Tables C-1 and C-2), as revised on 11/29/2013 (78 FR 71909).

CO2	70.22	kg/MMBtu	40CFR98 Subpart C, Table C-1	125
	19,351	lb/ Mgal	= 70.22 kg/MMBtu x 2.2046 lb/kg x 125.0 MMBtu/Mgal	
CH4	3.00E-03	kg/MMBtu	40CFR98 Subpart C, Table C-2	
	0.8267	lb/ Mgal	= 3.00E-03 kg/MMBtu x 2.2046 lb/kg x 125.0 MMBtu/Mgal	
N2O	6.00E-04	kg/MMBtu	40CFR98 Subpart C, Table C-2	
	0.1653	lb/ Mgal	= 6.00E-04 kg/MMBtu x 2.2046 lb/kg x 125.0 MMBtu/Mgal	
CO2e				
CO2e Factor:	19,421	lb/ Mgal	40CFR98 Subpart A	

8. Coal Handling Operations (KyEIS ID#s 7, 9, 13 & 16)

> Fugitive PM emissions due to receiving, storing, conveying, crushing, and handling of coal are documented in this section.

8.1 Emission Unit Nomenclature and Process Rates

> Process rates for each conveyor/transfer point upon which emissions estimates are based are also provided below.

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Construc. Date	Process Rate (ton/hr)	Control Description
Coal Handling Operations 07					
West Track Hopper	07	1	1/1/1970	820	Enclosures
Conveyor A-1	07	2	1/1/1970	820	Enclosures
Conveyor E	07	3	1/1/1970	820	Enclosures
Conveyor F	07	4	1/1/1970	820	Enclosures
Conveyor G	07	5	1/1/1970	820	Enclosures
Conveyor H	07	6	1/1/1970	820	Enclosures
Coal Handling Operations 09					
East Track Hopper	09	1	1/1/1993	820	Enclosures
Conveyor A	09	2	1/1/1970	820	Enclosures
Conveyor B	09	3	1/1/1970	1,640	Enclosures
Conveyor C	09	4	1/1/1970	820	Enclosures
Conveyor J	09	5	1/1/1970	1,640	Enclosures
Coal Stockpile	09	6	1/1/1970	1,640	Enclosures
Coal Handling Operations 13					
Conveyor D [Tripper for Units 1 & 2]	13	1	1/1/1956	820	High Efficiency Cyclone
Conveyor K-1 [Upper Tripper for Unit 3]	13	2	1/1/1970	820	Baghouse, Partial Enclosure
Conveyor K [Lower Tripper for Unit 3]	13	3	1/1/1970	820	Baghouse, Partial Enclosure
Coal Crushing	16	1	1/1/1956	1,640	Enclosure/Wet Scrubber

8.2 Source Classification Codes

> SCC assigned to each of the coal handling system emission units are documented below. Please note that in prior applications, the general SCC, 30501099, had been specified for all units. These have been updated to reflect unit-specific SCC where available.

Emission Unit	SCC	SCC Description	SCC Units
Coal Handling Operations 07			
West Track Hopper	30501008	Coal Mining, Cleaning, and Material Handling, Unloading (3-05-010-08)	Tons Coal Shipped
Conveyor A-1	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor E	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor F	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor G	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor H	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Coal Handling Operations 09			
East Track Hopper	30501008	Coal Mining, Cleaning, and Material Handling, Unloading (3-05-010-08)	Tons Coal Shipped
Conveyor A	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor B	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor C	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor J	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Coal Stockpile	30501099	Coal Mining, Cleaning, and Material Handling, Other Not Classified (3-05-010-99)	Tons Material Shipped
Coal Handling Operations 13			
Conveyor D [Tripper for Units 1 & 2]	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor K-1 [Upper Tripper for Unit 3]	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Conveyor K [Lower Tripper for Unit 3]	30501011	Coal Mining, Cleaning, and Material Handling, Coal Transfer (3-05-010-11)	Tons Coal Shipped
Coal Crushing	30501010	Coal Mining, Cleaning, and Material Handling, Crushing (3-05-010-10)	Tons Coal Shipped

8.3 Coal Stockpile Fugitive PM Emission Factors

> Fugitive PM emissions may be released from the stockpiling of coal through two mechanisms-- (1) placing of coal to the pile (from Conveyor B or directly from trucks), and (2) wind erosion. PM emissions are expected to be small due to natural characteristics of the coal received at the plant, as well as additional measures employed such as compaction and wet suppression.

8.31 Coal Transfer/Handling Emission Factors

> PM emission factors for conveyor transfer and drop points are calculated using Equation 1 from AP42 Section 13.2.4, Aggregate Handling and Storage Piles. The mean wind speed used in this equation is based on five years of data from Lexington (1988-1992 data set). The material moisture content used is based on AP42 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 calculated using AP42 have been reduced by 70% due to the presence of dust suppression measures.

> The following emission factor equation applies: (Equations 1 in AP42 13.2.4)

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
U	Mean Wind Speed (mph)	8.4	8.4	8.4
M	Material Moisture Content (%)	4.5	4.5	4.5
E	Emission Factor (lb/ton)	1.49E-03	7.06E-04	1.07E-04

8.32 Wind Erosion Emission Factors

> 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 measureable 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. Then, so that a single SCC unit based emission factor can be used for the coal stockpile, the emission rate is divided by the coal processing rate of the overall coal handling system.

> *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 AP42 Table 13.2.4-1.
p	Number of days with >0.01 in precipitation per year	130	days	AP42 Figure 13.2.1-2.
f	% of time unobstructed wind speed > 12 mph at mean pile height	12		Lexington NWS surface data 1988-1992 data set.
E	PM/PM10 Emission Factor (lb/day/acre)	1.99	lb/day/acre	

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

Coal surface area:	6	acre	
PM Emission Factor (lb/hr) (average)	0.50	lb/hr	
Coal handling area process rate:	1,640	ton/hr	
Wind Erosion PM Emission Factor (lb/ton)	3.04E-04	lb/ton	
Wind Erosion PM10 Emission Factor (lb/ton)	1.52E-04	lb/ton	Assumed to be 50% of PM
Wind Erosion PM2.5 Emission Factor (lb/hr)	6.08E-05	lb/ton	Assumed to be 20% of PM

8.33 Combined Coal Transfer/Handling and Wind Erosion Emission Factor

	PM	PM10	PM2.5
Material Handling Emission Factors (lb/ton)	1.49E-03	7.06E-04	1.07E-04
Wind Erosion Emission Factors (lb/ton)	3.04E-04	1.52E-04	6.08E-05
TOTAL (Uncontrolled)	1.80E-03	8.58E-04	1.68E-04
Control efficiency applied for dust suppression measures	70%	70%	70%
TOTAL (Controlled)	5.39E-04	2.58E-04	5.03E-05

8.4 Uncontrolled Emission Factors and Emission Rates

> The same PM/PM10 emission factors utilized in the previous Title V application for Brown Station (citing the Midwest Research Institute) and reflected in the KyEIS system are retained for this renewal application with the exception of those for the coal stockpile. These factors are close to what could alternatively be calculated using the methodology for aggregate handling and storage in AP42 Section 13.2.4. Control efficiencies previously referenced in prior applications are retained.

> PM2.5 emissions are estimated to be 20% of PM10 emissions.

> Coal stockpile fugitive emission factors have been updated as part of this renewal application since the prior factors in use were overly conservative.

Emission Unit	Uncontrolled Emission Factor (lb/ton)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Coal Handling Operations 07							
West Track Hopper							
PM	0.0004	MRI; 1996 Title V App	0.33	1.44	90%	0.03	0.14
PM10	0.0004	MRI; 1996 Title V App	0.33	1.44	90%	0.03	0.14
PM2.5	0.00008	Estimated 20% of PM10	0.07	0.29	90%	0.01	0.03
Conveyor A-1							
PM	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM10	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM2.5	0.00006	Estimated 20% of PM10	0.05	0.22	90%	0.00	0.02
Conveyor E							
PM	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM10	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM2.5	0.00006	Estimated 20% of PM10	0.05	0.22	90%	0.00	0.02
Conveyor F							
PM	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM10	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM2.5	0.00006	Estimated 20% of PM10	0.05	0.22	90%	0.00	0.02
Conveyor G							
PM	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM10	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM2.5	0.00006	Estimated 20% of PM10	0.05	0.22	90%	0.00	0.02
Conveyor H							
PM	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM10	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM2.5	0.00006	Estimated 20% of PM10	0.05	0.22	90%	0.00	0.02

Emission Unit	Uncontrolled Emission Factor (lb/ton)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Coal Handling Operations 09							
East Track Hopper							
PM	0.0004	MRI; 1996 Title V App	0.33	1.44	90%	0.03	0.14
PM10	0.0004	MRI; 1996 Title V App	0.33	1.44	90%	0.03	0.14
PM2.5	0.00008	Estimated 20% of PM10	0.07	0.29	90%	0.01	0.03
Conveyor A							
PM	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM10	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM2.5	0.00006	Estimated 20% of PM10	0.05	0.22	90%	0.00	0.02
Conveyor B							
PM	0.0003	MRI; 1996 Title V App	0.49	2.15	90%	0.05	0.22
PM10	0.0003	MRI; 1996 Title V App	0.49	2.15	90%	0.05	0.22
PM2.5	0.00006	Estimated 20% of PM10	0.10	0.43	90%	0.01	0.04
Conveyor C							
PM	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM10	0.0003	MRI; 1996 Title V App	0.25	1.08	90%	0.02	0.11
PM2.5	0.00006	Estimated 20% of PM10	0.05	0.22	90%	0.00	0.02
Conveyor J							
PM	0.0003	MRI; 1996 Title V App	0.49	2.15	90%	0.05	0.22
PM10	0.0003	MRI; 1996 Title V App	0.49	2.15	90%	0.05	0.22
PM2.5	0.00006	Estimated 20% of PM10	0.10	0.43	90%	0.01	0.04
Coal Stockpile							
PM	0.00180	AP42 & EPA450/3-88-008	2.95	12.91	70%	0.88	3.87
PM10	0.00086	Estimated 50% of PM	1.41	6.17	70%	0.42	1.85
PM2.5	0.00017	Estimated 20% of PM	0.28	1.21	70%	0.08	0.36
Coal Handling Operations 13							
Conveyor D [Tripper for Units 1 & 2]							
PM	0.0419	MRI; 1996 Title V App	34.36	150.49	92%	2.75	12.04
PM10	0.0419	MRI; 1996 Title V App	34.36	150.49	92%	2.75	12.04
PM2.5	0.00838	Estimated 20% of PM10	6.87	30.10	92%	0.55	2.41
Conveyor K-1 [Upper Tripper for Unit 3]							
PM	0.028	MRI; 1996 Title V App	22.96	100.56	99.5%	0.11	0.50
PM10	0.028	MRI; 1996 Title V App	22.96	100.56	99.5%	0.11	0.50
PM2.5	0.0056	Estimated 20% of PM10	4.59	20.11	99.5%	0.02	0.10
Conveyor K [Lower Tripper for Unit 3]							
PM	0.028	MRI; 1996 Title V App	22.96	100.56	99.5%	0.11	0.50
PM10	0.028	MRI; 1996 Title V App	22.96	100.56	99.5%	0.11	0.50
PM2.5	0.0056	Estimated 20% of PM10	4.59	20.11	99.5%	0.02	0.10
Coal Crushing							
Four Crushers and Crusher House							
PM	0.02	MRI; 1996 Title V App	32.80	143.66	99%	0.33	1.44
PM10	0.01	MRI; 1996 Title V App	16.40	71.83	99%	0.16	0.72
PM2.5	0.002	Estimated 20% of PM10	3.28	14.37	99%	0.03	0.14

9. Dry Fly Ash Handling (KyEIS ID# 21)

> PM emissions due to handling of fly ash collected in the dry ESPs of Units 1, 2 & 3 Boilers are documented in this section.

9.1 Emission Unit Nomenclature and Process Rates

> The nomenclature for the dry fly ash system and the maximum process rate upon which emissions are based is listed below.

Emission Unit Description	KyEIS Source ID#	KyEIS Process ID#	Construc. Date	Process Rate (ton/hr)	Control Description
Dry Fly Ash Handling	21	1	1/1/1982	79.5	PJFF

9.2 Source Classification Code

SCC:	30599999
SCC Description:	Mineral Products (3-05), Other Not Defined (3-05-999)
SCC Units:	Tons Product Produced

9.3 Uncontrolled Emission Factors and Emission Rates

> The same PM/PM10 emission factors utilized in the previous Title V application for Brown Station (citing Midwest Research Institute) and reflected in the KyEIS system are retained for this renewal application.

> PM2.5 emissions are estimated to be 20% of PM10 emissions.

Emission Unit Description	Uncontrolled Emission Factor (lb/ton)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	Control Efficiency (%)	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Dry Fly Ash Handling							
PM	3	MRI; 1996 Title V App	238.50	1,044.63	99.9%	0.24	1.04
PM10	3	MRI; 1996 Title V App	238.50	1,044.63	99.9%	0.24	1.04
PM2.5	0.6	Estimated 20% of PM10	47.70	208.93	99.9%	0.05	0.21

10. Peaking Combustion Turbines (KyEIS ID#s 23-29)

> Documentation of combustion turbine fuel firing rates, emission factors, and emission calculations are provided in this section.

10.1 Description and Nomenclature

> The 7 combustion turbines at Brown Station (CT5, CT6, CT7, CT8, CT9, CT10 & CT11) are each assigned a separate emission unit ID in the current Title V permit. Based on updates made to the 2008 KyEIS inventory, separate KyEIS Source ID#s are also now assigned to each turbine. Process ID#s are assigned for each fuel combusted (gas or distillate oil).

Turbine Name & Fuel	Title V Permit ID#	KyEIS Source ID#	KyEIS Process ID#
Combustion Turbine Unit 5 (Fuel: Natural Gas)	29	29	1
Combustion Turbine Unit 6 (Fuel: Distillate Oil)	27	27	1
Combustion Turbine Unit 6 (Fuel: Natural Gas)			2
Combustion Turbine Unit 7 (Fuel: Distillate Oil)	28	28	1
Combustion Turbine Unit 7 (Fuel: Natural Gas)			2
Combustion Turbine Unit 8 (Fuel: Distillate Oil)	25	25	1
Combustion Turbine Unit 8 (Fuel: Natural Gas)			2
Combustion Turbine Unit 9 (Fuel: Distillate Oil)	23	23	1
Combustion Turbine Unit 9 (Fuel: Natural Gas)			2
Combustion Turbine Unit 10 (Fuel: Distillate Oil)	24	24	1
Combustion Turbine Unit 10 (Fuel: Natural Gas)			2
Combustion Turbine Unit 11 (Fuel: Distillate Oil)	26	26	1
Combustion Turbine Unit 11 (Fuel: Natural Gas)			2

> CT 5, 8, 9, 10 & 11 are ABB GT 11N2 simple cycle combustion turbines equipped with water injection for NOX control.
> CT 6 and 7are ABB GT 24 simple cycle combustion turbines equipped with water injection for NOX control.
> All the turbines are capable of burning both natural gas and distillate oil, except for CT5, which is equipped to fire natural gas only.

10.2 Turbine Capacities and Construction Dates

Natural Gas Heating Value	1,020	MMBtu/MMscf	
Distillate Oil Heating Value	138	MMBtu/1000 gal	
Maximum Operating Hours Per Year -Fuel Oil	2,500	hr/yr	(PSD permit derived operating limit for fuel oil.)
Maximum Operating Hours Per Year -NG	8,760	hr/yr	

Turbine	Install Date	Heat Input Capacity (MMBtu/hr)	Maximum Gas Firing Rate (MMscf/hr)	Annual Gas Firing Rate (MMscf/yr)	Maximum Oil Firing Rate (1000gal/hr)	Annual Oil Firing Rate (1000galyr)
CT5	6/8/2001	1,368	1.341	11,749	na	na
CT6	8/11/1999	1,678	1.645	14,411	12.159	30,399
CT7	8/8/1999	1,678	1.645	14,411	12.159	30,399
CT8	3/1/1996	1,368	1.341	11,749	9.913	24,783
CT9	11/28/1995	1,368	1.341	11,749	9.913	24,783
CT10	12/22/1995	1,368	1.341	11,749	9.913	24,783
CT11	5/8/1996	1,368	1.341	11,749	9.913	24,783

Maximum heat input capacities are stated at ISO standard conditions.

10.3 Source Classification Codes

Turbines Firing Natural Gas:

SCC: 20100201
SCC Description: Electric Generation (2-01), Turbine (2-01-002-01)
SCC Units: Million Cubic Feet Natural Gas Burned

Turbines Firing Distillate Oil:

SCC: 20100101
SCC Description: Electric Generation (2-01), Turbine (2-01-001-01)
SCC Units: 1000 Gallons Distillate Oil (Diesel) Burned

10.4 Documentation of Emission Factors Used

10.41 Primary Pollutants- Natural Gas

> Per AP42 Section 3.1, a default heating value of 1,020 MMBtu/MMscf is used to convert AP42 factors in terms of lb/MMBtu to lb/MMscf.

CO

Uncontrolled Factor	43	lb/MMscf	Manufacture EF is used to calculated the PTE. Actual emissions will be based on the most recent performance test for each CT. Please see Appendix G.

NOX

Uncontrolled (CT5, 8, 9, 10, 11)	115.92	lb/MMscf	Manufacturer
Uncontrolled (CT6, 7)	99.54	lb/MMscf	Manufacturer
Water Injection Control Efficiency	65%		
Controlled (CT5, 8, 9, 10, 11)	40.57	lb/MMscf	
Controlled (CT6 & 7))	34.84	lb/MMscf	

Permit V-03-034 limits NOX to the following values when the turbines are fired with natural gas:

CT 5	25 ppmdv @15% O2
CT 6 & 7	25 ppmdv @15% O2
CTs 8, 9, 10, 11	42 ppmdv @15% O2

These limits can not be directly converted into an emission factor in terms of lb/MMscf since they are dependent on actual exhaust gas conditions. However, as a sample calculation, the conversion of the 25 ppmdv permit limit to units of lb/MMscf at typical conditions is shown below using CT6 as an example.

Example O2 concentration of exhaust gas	12.9%		
NOX limit at actual O2 conditions	33.90	ppmdv @ actual O2	= 25 ppmdv * (20.9-12.9)/(20.9-15)
Fd Factor for Gas (EPA Method 19)	8,710	dscf/MMBtu	
NOX limit at actual O2 conditions			
E (lb/MMBtu) = C (lb/dscf) * Fd (dscf/MMBtu) * 20.9/(20.9-%O2)			EPA Method 19
C (lb/dscf) = NOX concentration (ppm) * conversion factor			EPA Method 19
Conversion factor (ppm to lb/dscf) = 1.194E-7			EPA Method 19
C (lb/dscf) =	4.047E-06	lb/dscf	= 33.9 ppmdv * 1.194E-7
E (lb/MMBtu) (Equivalent Permit Limit) =	0.092	lb/MMBtu	= 0.000004 * 8710 dscf/MMBtu * 20.9/(20.9-12.9)
E (lb/MMscf) =	93.94	lb/MMscf	= 0.092 lb/MMBtu * 1020 MMBtu/MMscf

As shown by this calculation, the expected NOX emissions in terms of lb/MMscf are less than the equivalent allowable in terms of lb/MMscf.

SO2

Uncontrolled Factor	0.94	S lb/MMBtu	AP42 Table 3.1-2a (4/2000)
Gas Sulfur Content	8.615E-05	%	
	0.0826	lb/MMscf	= 0.94 * 0.000086 [lb/MMBtu] * 1020 MMBtu/MMscf

VOC

Uncontrolled Factor	2.10E-03	lb/MMBtu	AP42 Table 3.1-2a (4/2000)
	2.1420	lb/MMscf	= 0.0021 * 1020 MMBtu/MMscf

PM

Uncontrolled Factor	6.60E-03	lb/MMBtu	AP42 Table 3.1-2a (4/2000)
	6.732	lb/MMscf	= 0.0066 * 1020 MMBtu/MMscf

PM10

Uncontrolled Factor	6.732	lb/MMscf	Assume all PM is PM2.5

PM2.5

% of PM10 assumed to be PM2.5	100%		Assume all PM is PM2.5
Uncontrolled Factor	6.732	lb/MMscf	

10.42 Primary Pollutants- Distillate Oil

> Per AP42 Section 3.1, a default heating value of 138 MMBtu/1000 gal is used to convert AP42 factors in terms of lb/MMBtu to lb/1000gal.

CO

Uncontrolled Factor	3.30E-03	lb/MMBtu	AP42 Table 3.1-1 (4/2000)
	0.459	lb/1000gal	= 0.0033 * 139 MMBtu/1000gal

NOX

Uncontrolled (CT5, 8, 9, 10, 11)	24.36	lb/1000gal	Manufacturer
Uncontrolled (CT6, 7)	27.3	lb/1000gal	Manufacturer
Water Injection Control Efficiency	65%		
Controlled (CT5, 8, 9, 10, 11)	8.526	lb/1000gal	
Controlled (CT5, 8, 9, 10, 11)	9.555	lb/1000gal	

SO2

CT5, 8, 9, 10, 11

Uncontrolled Factor	1.01	S lb/MMBtu	AP42 Table 3.1-2a (4/2000)
Maximum sulfur content	0.05	%	
	7.02	lb/1000gal	= 1.01 * 0.05 lb/MMBtu * 139 MMBtu/1000gal

CT6, 7

Uncontrolled Factor	1.01	S lb/MMBtu	AP42 Table 3.1-2a (4/2000)
Maximum sulfur content	0.23	%	
	32.29	lb/1000gal	= 1.01 * 0.23 lb/MMBtu * 139 MMBtu/1000gal

VOC

Uncontrolled Factor	4.10E-04	lb/MMBtu	AP42 Table 3.1-2a (4/2000)
	0.057	lb/1000gal	= 0.00041 * 139 MMBtu/1000gal

PM

Uncontrolled Factor	1.20E-02	lb/MMBtu	AP42 Table 3.1-2a (4/2000)
	1.668	lb/1000gal	= 0.012 * 139 MMBtu/1000gal

PM10

Uncontrolled Factor	1.668	lb/1000gal	Assume all PM is PM2.5

PM2.5

% of PM10 assumed to be PM2.5	100%		Assume all PM is PM2.5
Uncontrolled Factor	1.668	lb/1000gal	

Lead

Uncontrolled Factor	8.90E-06	lb/MMBtu	EPA TAP EF Compilation 1988
	0.0012	lb/1000gal	= 0.0000089 * 139 MMBtu/1000gal

10.43 Gaseous HAP (Natural Gas Fired Turbines)

> Emission factors used for gaseous HAP that may be emitted when turbines are fired on natural gas are those published in AP42 Table 3.1-3 (4/2000).

	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	Emission Factor Basis
1,3-Butadiene	4.3E-07	4.39E-04	AP42 Tbl 3.1-3
Acetaldehyde	4.0E-05	4.08E-02	AP42 Tbl 3.1-3
Acrolein	6.4E-06	6.53E-03	AP42 Tbl 3.1-3
Benzene	1.2E-05	1.22E-02	AP42 Tbl 3.1-3
Ethylbenzene	3.2E-05	3.26E-02	AP42 Tbl 3.1-3
Formaldehyde	7.1E-04	7.24E-01	AP42 Tbl 3.1-3
Naphthalene	1.3E-06	1.33E-03	AP42 Tbl 3.1-3
PAH	2.2E-06	2.24E-03	AP42 Tbl 3.1-3
Propylene Oxide	2.9E-05	2.96E-02	AP42 Tbl 3.1-3
Toluene	1.3E-04	1.33E-01	AP42 Tbl 3.1-3
Xylenes	6.4E-05	6.53E-02	AP42 Tbl 3.1-3

10.44 Gaseous HAP (Distillate Oil Fired Turbines)

> Emission factors used for gaseous HAP that may be emitted when turbines are fired on distillate are those published in AP42 Table 3.1-4 (4/2000).

	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000gal)	Emission Factor Basis
1,3-Butadiene	1.6E-05	2.22E-03	AP42 Tbl 3.1-4
Benzene	5.5E-05	7.65E-03	AP42 Tbl 3.1-4
Formaldehyde	2.8E-04	3.89E-02	AP42 Tbl 3.1-4
Naphthalene	3.5E-05	4.87E-03	AP42 Tbl 3.1-4
PAH	4.0E-05	5.56E-03	AP42 Tbl 3.1-4

10.45 Metallic HAP (Distillate Oil Fired Turbines)

> Emission factors used for metallic HAP that may be emitted when turbines are fired on distillate oil are those published in AP42 Table 3.1-5 (4/2000). For beryllium, a factor published in the EPA report "TAP Emission Factors- A Compilation for Selected Air Toxic Compounds and Sources, 2nd Edition" (450/2-90-011) is used.

	Emission Factor (lb/MMBtu)	Emission Factor (lb/1000gal)	Emission Factor Basis
Arsenic	1.1E-05	1.53E-03	AP42 Tbl 3.1-5
Beryllium	3.2E-07	4.50E-05	EPA 450/2-90-011
Cadmium	4.8E-06	6.67E-04	AP42 Tbl 3.1-5
Chromium	1.1E-05	1.53E-03	AP42 Tbl 3.1-5
Manganese	7.9E-04	1.10E-01	AP42 Tbl 3.1-5
Mercury	1.2E-06	1.67E-04	AP42 Tbl 3.1-5
Nickel	4.6E-06	6.39E-04	AP42 Tbl 3.1-5
Selenium	2.5E-05	3.48E-03	AP42 Tbl 3.1-5

10.5 Emission Calculations for Turbines Based on Factors Documented

10.51 CTs 5, 8, 9, 10, 11 Fired with <u>Natural Gas</u>

> Calculations shown are for a single turbine. Each turbine has the same potential emission rate.

Maximum Hourly Gas Usage (CT5, 8, 9, 10, 11):	1.341	MMscf/hr
Maximum Annual Gas Usage (CT5, 8, 9, 10, 11):	11,749	MMscf/yr

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/MMscf)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Primary Pollutants							
CO	43	Manufacture	57.7	252.6	na	na	na
NOX	115.92	Manufacturer	155.5	681.0	65%	54.4	238.3
SO2	0.08	AP42 Table 3.1-2a (4/2000)	0.11	0.49	na	na	na
VOC	2.142	AP42 Table 3.1-2a (4/2000)	2.9	12.6	na	na	na
PM	6.732	AP42 Table 3.1-2a (4/2000)	9.0	39.5	na	na	na
PM10	6.732	Assume all PM is PM2.5	9.0	39.5	na	na	na
PM2.5	6.732	Assume all PM is PM2.5	9.0	39.5	na	na	na
CO_2E	119,439	40 CFR 98 Subpart C	160,189	701,626	na	na	na
Gaseous HAPs							
1,3-Butadiene	4.39E-04	AP42 Tbl 3.1-3	5.88E-04	2.58E-03	na	na	na
Acetaldehyde	4.08E-02	AP42 Tbl 3.1-3	5.47E-02	2.40E-01	na	na	na
Acrolein	6.53E-03	AP42 Tbl 3.1-3	8.76E-03	3.83E-02	na	na	na
Benzene	1.22E-02	AP42 Tbl 3.1-3	1.64E-02	7.19E-02	na	na	na
Ethylbenzene	3.26E-02	AP42 Tbl 3.1-3	4.38E-02	1.92E-01	na	na	na
Formaldehyde	7.24E-01	AP42 Tbl 3.1-3	0.971	4.254	na	na	na
Naphthalene	1.33E-03	AP42 Tbl 3.1-3	1.78E-03	7.79E-03	na	na	na
PAH	2.24E-03	AP42 Tbl 3.1-3	3.01E-03	1.32E-02	na	na	na
Propylene Oxide	2.96E-02	AP42 Tbl 3.1-3	3.97E-02	1.74E-01	na	na	na
Toluene	1.33E-01	AP42 Tbl 3.1-3	0.178	0.779	na	na	na
Xylenes	6.53E-02	AP42 Tbl 3.1-3	8.76E-02	3.83E-01	na	na	na

> CO is limited to 75 lb/hr and 93.8 tpy per turbine.
> NOX is limited to 25 ppmdv @15% O2 for CT5 and 42 ppmdv @15% O2 for CTs 8, 9, 10, & 11, when firing natural gas.
> SO2 is limited to 444 lb/hr per turbine
> VOC is limited to 20.4 lb/hr and 25.5 tpy per turbine.
> PM is limited to 67 lb/hr and 83.8 tpy per turbine.

10.52 CTs 6 & 7 Fired with Natural Gas

> Calculations shown are for a single turbine. Each turbine has the same potential emission rate.

Maximum Hourly Gas Usage (CT6 & 7):	1.645	MMscf/hr
Maximum Annual Gas Usage (CT6 & 7):	14,411	MMscf/yr

	Uncontrolled Emission Factor (lb/MMscf)	Basis	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tpy)	Control Efficiency	Controlled Emissions (lb/hr)	Controlled Emissions (tpy)
Primary Pollutants							
CO	43	Manufacture	70.7	309.8	na	na	na
NOX	99.54	Manufacturer	163.8	717.2	65%	57.3	251.0
SO2	0.08	AP42 Table 3.1-2a (4/2000)	0.14	0.60	na	na	na
VOC	2.142	AP42 Table 3.1-2a (4/2000)	3.5	15.4	na	na	na
PM	6.732	AP42 Table 3.1-2a (4/2000)	11.1	48.5	na	na	na
PM10	6.732	Assume all PM is PM2.5	11.1	48.5	na	na	na
PM2.5	6.732	Assume all PM is PM2.5	11.1	48.5	na	na	na
CO_2E	119,439	40 CFR 98 Subpart C	196,489	860,620	na	na	na
Gaseous HAPs							
1,3-Butadiene	4.39E-04	AP42 Tbl 3.1-3	7.22E-04	3.16E-03	na	na	na
Acetaldehyde	4.08E-02	AP42 Tbl 3.1-3	6.71E-02	2.94E-01	na	na	na
Acrolein	6.53E-03	AP42 Tbl 3.1-3	1.07E-02	4.70E-02	na	na	na
Benzene	1.22E-02	AP42 Tbl 3.1-3	2.01E-02	8.82E-02	na	na	na
Ethylbenzene	3.26E-02	AP42 Tbl 3.1-3	5.37E-02	2.35E-01	na	na	na
Formaldehyde	7.24E-01	AP42 Tbl 3.1-3	1.191	5.218	na	na	na
Naphthalene	1.33E-03	AP42 Tbl 3.1-3	2.18E-03	9.55E-03	na	na	na
PAH	2.24E-03	AP42 Tbl 3.1-3	3.69E-03	1.62E-02	na	na	na
Propylene Oxide	2.96E-02	AP42 Tbl 3.1-3	4.87E-02	2.13E-01	na	na	na
Toluene	1.33E-01	AP42 Tbl 3.1-3	0.218	0.955	na	na	na
Xylenes	6.53E-02	AP42 Tbl 3.1-3	0.107	0.470	na	na	na

> CO is limited to 112.5 lb/hr and 140.63 tpy per turbine.
> NOX is limited to 25 ppmdv @15% O2 when firing natural gas.
> SO2 is limited to 666 lb/hr per turbine.
> VOC is limited to 30.6 lb/hr and 38.25 tpy per turbine.
> PM is limited to 100.5 lb/hr and 125.63 tpy per turbine.

10.53 CTs 8, 9, 10, 11 Fired with Distillate Oil

> Calculations shown are for a single turbine. Each turbine has the same potential emission rate.

Maximum Hourly Distillate Oil Usage (CT8, 9, 10, 11): 9.913 1000gal/hr
Maximum Annual Distillate Oil Usage (CT8, 9, 10, 11): 24,783 1000gal/yr

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/1000gal)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Primary Pollutants							
CO	0.459	AP42 Table 3.1-1 (4/2000)	4.5	5.7	na	na	na
NOX	24.36	Manufacturer	241.5	301.9	65%	84.5	105.6
SO2	7.02	AP42 Table 3.1-2a (4/2000)	69.6	87.0	na	na	na
VOC	0.057	AP42 Table 3.1-2a (4/2000)	0.6	0.7	na	na	na
PM	1.668	AP42 Table 3.1-2a (4/2000)	16.5	20.7	na	na	na
PM10	1.668	Assume all PM is PM2.5	16.5	20.7	na	na	na
PM2.5	1.668	Assume all PM is PM2.5	16.5	20.7	na	na	na
Lead	0.0012	EPA TAP EF Compilation	0.012	0.015	na	na	na
CO_2E	22,578	40 CFR 98 Subpart C	223,821	279,776	na	na	na
Gaseous HAPs							
1,3-Butadiene	2.22E-03	AP42 Tbl 3.1-4	2.20E-02	2.76E-02	na	na	na
Benzene	7.65E-03	AP42 Tbl 3.1-4	7.58E-02	9.47E-02	na	na	na
Formaldehyde	3.89E-02	AP42 Tbl 3.1-4	3.86E-01	4.82E-01	na	na	na
Naphthalene	4.87E-03	AP42 Tbl 3.1-4	4.82E-02	6.03E-02	na	na	na
PAH	5.56E-03	AP42 Tbl 3.1-4	5.51E-02	6.89E-02	na	na	na
Metallic HAPs							
Arsenic	1.53E-03	AP42 Tbl 3.1-5	1.52E-02	1.89E-02	na	na	na
Beryllium	4.50E-05	EPA 450/2-90-011	4.46E-04	5.58E-04	na	na	na
Cadmium	6.67E-04	AP42 Tbl 3.1-5	6.61E-03	8.27E-03	na	na	na
Chromium	1.53E-03	AP42 Tbl 3.1-5	1.52E-02	1.89E-02	na	na	na
Manganese	1.10E-01	AP42 Tbl 3.1-5	1.09E+00	1.36E+00	na	na	na
Mercury	1.67E-04	AP42 Tbl 3.1-5	1.65E-03	2.07E-03	na	na	na
Nickel	6.39E-04	AP42 Tbl 3.1-5	6.34E-03	7.92E-03	na	na	na
Selenium	3.48E-03	AP42 Tbl 3.1-5	3.44E-02	4.31E-02	na	na	na

> CO is limited to 75 lb/hr and 93.8 tpy per turbine.
> NOX is limited to 65 ppmdv @15% O2 for CTs 8, 9, 10, & 11, when firing distillate oil.
> SO2 is limited to 444 lb/hr per turbine when 7 or less turbines are fired and 402 lb/hr when 8 turbine are fired.
> VOC is limited to 20.4 lb/hr and 25.5 tpy per turbine.
> PM is limited to 67 lb/hr and 83.8 tpy per turbine.
> Beryllium is limited to 3.37E-3 lb/hr and 4.21E-3 tpy per turbine.

10.54 CTs 6 & 7 Fired with Distillate Oil

> Calculations shown are for a single turbine. Each turbine has the same potential emission rate.

Maximum Hourly Distillate Oil Usage (CT6 & 7):	12.159	1000gal/hr
Maximum Annual Distillate Oil Usage (CT6 & 7):	30,399	1000gal/yr

	Uncontrolled Emission Factor		Uncontrolled Emissions		Control Efficiency	Controlled Emissions	
	(lb/1000gal)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Primary Pollutants							
CO	0.459	AP42 Table 3.1-1 (4/2000)	5.6	7.0	na	na	na
NOX	27.3	Manufacturer	332.0	414.9	65%	116.2	145.2
SO2	32.29	AP42 Table 3.1-2a (4/2000)	392.6	490.8	na	na	na
VOC	0.057	AP42 Table 3.1-2a (4/2000)	0.7	0.9	na	na	na
PM	1.668	AP42 Table 3.1-2a (4/2000)	20.3	25.4	na	na	na
PM10	1.668	Assume all PM is PM2.5	20.3	25.4	na	na	na
PM2.5	1.668	Assume all PM is PM2.5	20.3	25.4	na	na	na
Lead	0.0012	EPA TAP EF Compilation	0.015	0.019	na	na	na
CO_2E	22,578	40 CFR 98 Subpart C	274,541	343,176	na	na	na
Gaseous HAPs							
1,3-Butadiene	2.22E-03	AP42 Tbl 3.1-4	2.70E-02	3.38E-02	na	na	na
Benzene	7.65E-03	AP42 Tbl 3.1-4	9.30E-02	1.16E-01	na	na	na
Formaldehyde	3.89E-02	AP42 Tbl 3.1-4	4.73E-01	5.92E-01	na	na	na
Naphthalene	4.87E-03	AP42 Tbl 3.1-4	5.92E-02	7.39E-02	na	na	na
PAH	5.56E-03	AP42 Tbl 3.1-4	6.76E-02	8.45E-02	na	na	na
Metallic HAPs							
Arsenic	1.53E-03	AP42 Tbl 3.1-5	1.86E-02	2.32E-02	na	na	na
Beryllium	4.50E-05	EPA 450/2-90-011	5.48E-04	6.85E-04	na	na	na
Cadmium	6.67E-04	AP42 Tbl 3.1-5	8.11E-03	1.01E-02	na	na	na
Chromium	1.53E-03	AP42 Tbl 3.1-5	1.86E-02	2.32E-02	na	na	na
Manganese	1.10E-01	AP42 Tbl 3.1-5	1.34E+00	1.67E+00	na	na	na
Mercury	1.67E-04	AP42 Tbl 3.1-5	2.03E-03	2.54E-03	na	na	na
Nickel	6.39E-04	AP42 Tbl 3.1-5	7.77E-03	9.72E-03	na	na	na
Selenium	3.48E-03	AP42 Tbl 3.1-5	4.23E-02	5.28E-02	na	na	na

> CO is limited to 112.5 lb/hr and 140.63 tpy per turbine.
> NOX is limited to 42 ppmdv @15% O2 when firing distillate oil.
> SO2 is limited to 666 lb/hr per turbine.
> VOC is limited to 30.6 lb/hr and 38.25 tpy per turbine.
> PM is limited to 100.5 lb/hr and 125.63 tpy per turbine.
> Beryllium is limited to 5.057E-3 lb/hr and 6.35E-3 tpy per turbine.

11. Limestone Handling System (KyEIS ID#s 30-34)

> Documentation of limestone handling system process rates, emission factors, and emission calculations.

11.1 Emission Unit Nomenclature and Process Rates

> 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.

> Due to changes in planned design since the minor revision application for the FGD project was submitted to KDAQ in March 2005, a new nomenclature is being proposed for the limestone system emissions units.

> Process rates for each operation and conveyor/transfer point used in deriving SCC based emission factors are listed below.

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Construc. Date	Process Rate (ton/hr)	Control Description
Limestone Truck Dump Station #1	30	1	1/1/2008	250	Fabric Filter
Limestone Truck Dump Station #2	31	1	1/1/2008	250	Fabric Filter
Limestone Stacking Tube	32	1	3/1/2008	500	Fabric Filter
Limestone Reclaim Conveyor #1	33	1	3/1/2008	500	Fabric Filter
Limestone Reclaim Conveyor #2	34	1	3/1/2008	500	Fabric Filter

11.2 Source Classification Codes

Emission Unit	KyEIS Source ID#	SCC	SCC Description	SCC Units
Limestone Truck Dump Station #1	30	30510405	Bulk Materials Unloading Operation (3-05-104), Limestone (3-05-104-05)	Tons Material Processed
Limestone Truck Dump Station #2	31	30510405	Bulk Materials Unloading Operation (3-05-104), Limestone (3-05-104-05)	Tons Material Processed
Limestone Stacking Tube	32	30510305	Bulk Materials Open Stockpiles (3-05-103), Limestone (3-05-103-05)	Tons Material Processed
Limestone Reclaim Conveyor #1	33	30510105	Bulk Materials Conveyors (3-05-101), Limestone (3-05-101-05)	Tons Material Processed
Limestone Reclaim Conveyor #2	34	30510105	Bulk Materials Conveyors (3-05-101), Limestone (3-05-101-05)	Tons Material Processed

11.3 Documentation of PM/PM10 Emission Factors Used

> PM that may be generated at the limestone transfer points are each captured and controlled in a fabric filter system. PM potential emissions are estimated based on vendor design filter specifications.

> The filters are designed to achieve a control efficiency greater than 99.9% at high inlet loading conditions. However, control efficiencies decrease with filter inlet loadings. Actual inlet loadings under normal operations will be less than loadings the filters are capable of accommodating The estimated uncontrolled emissions correspond to a slightly lower average control efficiency of 98% expected under the normally lower inlet loadings.

> There are two fans associated with each Truck Dump Station Filter. The flowrate listed below for each station is the combined value for both fans.

Emission Unit Filter System	KyEIS Source ID#	Design Fan Exhaust Rate (acfm)	Exit Grain Loading (gr/acf)	Controlled Emission Rate (lb/hr)	Design Control Efficiency (%)	Represented Uncontrolled Emission Rate (lb/hr)	SCC Based Emission Factor (lb/ton)
Limestone Truck Dump Station #1	30	8,828	0.0044	0.33	98%	16.6	0.067
Limestone Truck Dump Station #2	31	8,828	0.0044	0.33	98%	16.6	0.067
Limestone Stacking Tube	32	1,923	0.01	0.16	98%	8.2	0.016
Limestone Reclaim Conveyor #1	33	1,923	0.01	0.16	98%	8.2	0.016
Limestone Reclaim Conveyor #2	34	1,923	0.01	0.16	98%	8.2	0.016

> The filter systems on the Limestone Stacking Tube and Reclaim Conveyors are subject to a PM emission standard under NSPS Subpart OOO of 0.022 gr/dscf. The filter systems on the Truck Unloading Stations are exempt from NSPS Subpart OOO PM standards per 40 CFR 60.672(d).

11.4 PM/PM10/PM2.5 Emission Calculations Based on Factors Documented

PM/PM10		Uncontrolled Emission Factor		Uncontrolled PM/PM10 Emissions		Control Efficiency	Controlled PM/PM10 Emissions	
Emission Unit	KyEIS Source ID#	(lb/ton)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Limestone Truck Dump Station #1	30	0.067	Exit Loading Spec.	16.6	72.9	98%	0.33	1.46
Limestone Truck Dump Station #2	31	0.067	Exit Loading Spec.	16.6	72.9	98%	0.33	1.46
Limestone Stacking Tube	32	0.016	Exit Loading Spec.	8.2	36.1	98%	0.16	0.72
Limestone Reclaim Conveyor #1	33	0.016	Exit Loading Spec.	8.2	36.1	98%	0.16	0.72
Limestone Reclaim Conveyor #2	34	0.016	Exit Loading Spec.	8.2	36.1	98%	0.16	0.72

No test data or vendor information is available to estimate that portion of PM emissions that will be in the PM2.5 size range or less. As PM generated is solely from material handling, it is expected that fine particulate would only make up a minor portion of total PM10. Conservatively, PM2.5 emissions are estimated as 20% of PM10 emissions.

PM2.5		Uncontrolled Emission Factor		Uncontrolled PM2.5 Emissions		Control Efficiency	Controlled PM2.5 Emissions	
Emission Unit	KyEIS Source ID#	(lb/ton)	Basis	(lb/hr)	(tpy)		(lb/hr)	(tpy)
Limestone Truck Dump Station #1	30	0.0133	Estimated 20% of PM1(	3.3	14.6	98%	0.07	0.29
Limestone Truck Dump Station #2	31	0.0133	Estimated 20% of PM1(	3.3	14.6	98%	0.07	0.29
Limestone Stacking Tube	32	0.0033	Estimated 20% of PM1(	1.6	7.2	98%	0.03	0.14
Limestone Reclaim Conveyor #1	33	0.0033	Estimated 20% of PM1(	1.6	7.2	98%	0.03	0.14
Limestone Reclaim Conveyor #2	34	0.0033	Estimated 20% of PM1(	1.6	7.2	98%	0.03	0.14

12. Road Fugitives from Truck Traffic on Unpaved and Paved Roads (KyEIS ID# 35)

> Fugitive PM emissions potentially caused due to vehicle movement on plant roads are estimated in this section using methodologies of AP42 Section 13.2.1 (Paved) and 13.2.2 (Unpaved), 11/2006 Edition. Emissions are expressed as a function of vehicle miles traveled (VMT).

>

12.1 Annual Material Process Rates

> Road emissions are grouped into one of 4 categories based on type of truck-- coal, limestone, gypsum, or all others.

> For coal, limestone, and gypsum, VMT can be estimated each year based on the tons of material received and the approximate weight of material carried per trip. For all other types of vehicle traffic, a fixed estimate of annual VMT is set.

> Annual material process rate totals listed below are estimates of maximum deliveries via truck. For example, the annual coal volume is based on a projection of the maximum coal that would be received at the plant per year and assuming 7% is delivered by truck. This approach is conservative since in the future, 3% or less of the coal is expected to be delivered via truck.

	Annual Total (tons)	Full Truck Weight (tons)	Empty Truck Weight (tons)	Material Per Trip (tons)	Annual Trips (trips/yr)
Coal Delivered Via Truck	125,300	60	18	42	2,983
Limestone Delivered	250,000	40	18	22	11,364
Gypsum Hauled to Ash Basin	350,000	57	31	26	13,462

12.2 Truck Routes and Mileage

> The round trip distance each type of truck takes while on-site, and the portion unpaved and paved, are estimated based on site plan drawings.

	On-Site Round-Trip Distance (mi)	Annual Trips (trips/yr)	Annual VMT (VMT/yr)	% of Route Unpaved	% of Route Paved	Unpaved VMT (VMT/yr)	Paved VMT (VMT/yr)
Coal Delivery Trucks	2.0	2,983	5,967	5%	95%	298	5,668
Limestone Delivery Trucks	0.9	11,364	10,227	0%	100%	0	10,227
Gypsum Haul Trucks	0.7	13,462	9,423	30%	70%	2,827	6,596
Other Raw Material Trucks			10,000	10%	90%	1,000	9,000
						4,125	31,492

12.3 Unpaved Road Emission Factors

> The methodology presented in AP-42 Section 13.2.2 (11/2006) was used to derive fugitive PM emission factors for truck traffic on unpaved road surfaces within the plant.

> The following emission factor equation applies: (Equations 1a and 2 in AP42 13.2.2)

E (lb/VMT) = $[(k)(s/12)^{a}(W/3)^{b}]((365-P)/365)$

where:		PM	PM10	PM2.5
k	Particle Size Multiplier (lb/VMT)	4.9	1.5	0.15
a	Constant	0.7	0.9	0.9
b	Constant	0.45	0.45	0.45
s	Surface Material Silt Content (%)	3.9	3.9	3.9
P	Days with Precipitation	125	125	125

> The road surface silt content value is that used by EPA in the 1999 National Emissions Inventory for unpaved roads in Kentucky.

> Estimated mean number of days with 0.01 inch or more of precipitation for central Kentucky is from AP-42 Figure 13.2.2-1 (11/2006).

> For purposes of representing emissions in the Title V renewal application, the control efficiency provided by existing road dust suppression methods and work practices is not accounted for, which results in a conservative estimate of PM fugitive emissions.

Coal Delivery Trucks		PM	PM10	PM2.5
W	Average Vehicle Weight (tons)	39	39	39
E	Uncontrolled Emission Factor (lb/VMT)	4.653	1.138	0.114
Limestone Delivery Trucks				
W	Average Vehicle Weight (tons)	29	29	29
E	Uncontrolled Emission Factor (lb/VMT)	4.072	0.996	0.100
Gypsum Haul Trucks				
W	Average Vehicle Weight (tons)	44	44	44
E	Uncontrolled Emission Factor (lb/VMT)	4.912	1.201	0.120
All Other On-Site Truck Traffic				
W	Average Vehicle Weight (tons)	15	15	15
E	Uncontrolled Emission Factor (lb/VMT)	3.027	0.740	0.074

12.4 Paved Road Emission Factors

> The methodology presented in AP-42 Section 13.2.1 (11/2006) was used to derive fugitive PM emission factors for truck traffic on paved road surfaces within the plant.

> The following emission factor equation applies: (Equation 2 in AP43 13.2.1)

E (lb/VMT) = $[(k)(sL/2)^{0.65}(W/3)^{1.5} - C](1-(P/4N))$

where:		PM	PM10	PM2.5
k	Particle Size Multiplier (lb/VMT)	0.082	0.016	0.0024
sL	Silt Loading (g/m2)	0.6	0.6	0.6
C	Factor for Exhaust, Brake Wear & Tire Wear (lb/VMT)	0.00047	0.00047	0.00036
P	Days with Precipitation	125	125	125
N	Number of days in averaging period	365	365	365

> The road surface silt loading value is from AP42 Table 13.2.1-3 (11/2006) for the <500 ADT category.

> C value is from AP42 Table 13.2.1-2 (11/2006). PM30 is used as a surrogate for PM.

> Estimated mean number of days with 0.01 inch or more of precipitation for central Kentucky is from AP-42 Figure 13.2.1-2 (11/2006).

> For purposes of representing emissions in the Title V renewal application, the control efficiency provided by existing road dust suppression methods and work practices is not accounted for, which results in a conservative estimate of PM fugitive emissions.

Coal Delivery Trucks		PM	PM10	PM2.5
W	Average Vehicle Weight (tons)	39	39	39
E	Uncontrolled Emission Factor (lb/VMT)	1.606	0.313	0.047
Limestone Delivery Trucks				
W	Average Vehicle Weight (tons)	29	29	29
E	Uncontrolled Emission Factor (lb/VMT)	1.030	0.201	0.030
Gypsum Haul Trucks				
W	Average Vehicle Weight (tons)	44	44	44
E	Uncontrolled Emission Factor (lb/VMT)	1.925	0.375	0.056
All Other On-Site Truck Traffic				
W	Average Vehicle Weight (tons)	15	15	15
E	Uncontrolled Emission Factor (lb/VMT)	0.383	0.074	0.011

12.5 Fugitive PM Emissions from Roads

Truck Category	Unpaved Road Miles (VMT/yr)	Unpaved Road Factor (lb/VMT)	Unpaved Road Emissions (tpy)	Paved Road Miles (VMT/yr)	Paved Road Factor (lb/VMT)	Paved Road Emissions (tpy)	Total Road Emissions (tpy)	Hourly Average Emissions (lb/hr)
PM								
Coal Delivery Trucks	298	4.653	0.69	5,668	1.606	4.55	5.25	1.20
Limestone Delivery Trucks	0	4.072	0.00	10,227	1.030	5.27	5.27	1.20
Gypsum Haul Trucks	2,827	4.912	6.94	6,596	1.925	6.35	13.29	3.03
Other Raw Material Trucks	1,000	3.027	1.51	9,000	0.383	1.72	3.24	0.74
TOTAL	4,125		9.15	31,492		17.89	27.04	6.17
				Overall SCC Factor (lb/VMT):			1.519	
PM10								
Coal Delivery Trucks	298	1.138	0.17	5,668	0.313	0.89	1.06	0.24
Limestone Delivery Trucks	0	0.996	0.00	10,227	0.201	1.03	1.03	0.23
Gypsum Haul Trucks	2,827	1.201	1.70	6,596	0.375	1.24	2.94	0.67
Other Raw Material Trucks	1,000	0.740	0.37	9,000	0.074	0.33	0.70	0.16
TOTAL	4,125		2.24	31,492		3.49	5.72	1.31
				Overall SCC Factor (lb/VMT):			0.321	
PM2.5								
Coal Delivery Trucks	298	0.114	0.02	5,668	0.047	0.13	0.15	0.03
Limestone Delivery Trucks	0	0.100	0.00	10,227	0.030	0.15	0.15	0.03
Gypsum Haul Trucks	2,827	0.120	0.17	6,596	0.056	0.18	0.35	0.08
Other Raw Material Trucks	1,000	0.074	0.04	9,000	0.011	0.05	0.09	0.02
TOTAL	4,125		0.22	31,492		0.52	0.74	0.17
				Overall SCC Factor (lb/VMT):			0.042	

12.6 Source Classification Code

SCC:	30501024
SCC Description:	Coal Mining, Cleaning, and Material Handling (See 305310) (3-05-010), Hauling (3-05-010-24)
SCC Units:	Miles Vehicle Travelled

13. Cooling Towers (KyEIS ID#s 36-38)

> 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 are estimated using the procedures of AP42 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.

> In the existing Title V permit, the cooling towers are designated as insignificant activities. Consistent with previous correspondence submitted to KDAQ in May 2008, the cooling towers are being redesignated as significant emission units as part of this Title V renewal application for administrative purposes.

13.1 Source Classification Code

SCC:	38500101
SCC Description:	Mechanical Draft (3-85-001-01)
SCC Units:	Million Gallons Cooling Water Throughput

13.2 Cooling Tower Recirculation Rates

Cooling Tower	KyEIS Source ID#	Recirculation Flow Rate (gpm)	Recirculation Flow Rate (10^6gal/hr)
Unit 1 Cooling Tower with Drift Eliminators	36	68,000	4.08
Unit 2 Cooling Tower with Drift Eliminators	37	100,000	6.00
Unit 3 Cooling Tower with Drift Eliminators	38	173,000	10.38

13.3 Recirculation Water Total Dissolved Solids Concentrations

> The TDS content of the cooling tower water is estimated by multiplying the make-up water TDS content by the cooling tower "cycles of concentration", as noted in AP42 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.

Cooling Tower	TDS in Make-up Water (ppm)	Cycles of Concentration	TDS in Recirculation Water (ppm)
Unit 1 Cooling Tower with Drift Eliminators	303	1.8	545.4
Unit 2 Cooling Tower with Drift Eliminators	303	1.6	484.8
Unit 3 Cooling Tower with Drift Eliminators	303	1.7	515.1

13.4 PM Emission Factors for Cooling Towers

> The design specifications for the drift eliminators on Cooling Towers Unit 1, 2, and 3 are 0.005% drift loss.

> 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 was adjusted by this value.

Cooling Tower	Drift Loss (gal drift/gal flow)	Drift Mass Governed by Atmospheric Dispersion	TDS in Recirculation Water (ppm)	PM Emission Factor (lb/10^6gal)
Unit 1 Cooling Tower with Drift Eliminators	0.00005	31.3%	545.4	0.0712
Unit 2 Cooling Tower with Drift Eliminators	0.00005	31.3%	484.8	0.0633
Unit 3 Cooling Tower with Drift Eliminators	0.00005	31.3%	515.1	0.0672

Sample Calculation:

0.00005 gal/gal x 0.313 x 8.34 lb/gal x 545.4/10^6 lb PM/lb x 10^6 = 0.0712 lb/10^6 gal flow

13.5 Cooling Tower PM Emission Rates

> The percentage of PM emissions that are in the PM10 size range or smaller can be estimated using the methodology presented in "Calculating Realistic PM10 Emissions from Cooling Towers", *Environmental Progress* , Volume 21, Issue 2 (April 20, 2004). In this paper, the PM10 percentage is shown as a function of the circulating water TDS. For towers with a TDS content of less than 1000 ppm, over 80% of the PM is predicted to be PM10. Based on the Brown Station water TDS values, which are low, all cooling tower PM emissions are assumed to be in the form of PM10.

> No data is available by which the percentage of PM10 emissions in the PM2.5 size range can be reasonably estimated. PM2.5 emissions are set equal to PM10, although this simplification likely over estimates PM2.5.

Cooling Tower	Emission Factor (lb10^6gal)	Emission Factor Basis	Recirculation Flow Rate (10^6gal/hr)	PM/PM10/PM2.5 Emissions (lb/hr)	PM/PM10/PM2.5 Emissions (tpy)
Unit 1 Cooling Tower with Drift Eliminators	0.0712	AP42 13.4 (1/1995)	4.08	0.290	1.272
Unit 2 Cooling Tower with Drift Eliminators	0.0633	AP42 13.4 (1/1995)	6.00	0.380	1.663
Unit 3 Cooling Tower with Drift Eliminators	0.0672	AP42 13.4 (1/1995)	10.38	0.698	3.057

Sample Calculation:

0.0712 lb/10^6 gal x 4.08 10^6gal/hr = 0.2904 lb/hr

14. Dix Dam Crest Gate Gasoline-Fired Emergency Generator (KyEIS ID# 39)

> Documentation of capacity, emission factors, and emission calculations for gasoline-fired emergency generator at Dix Dam Crest Gate.

14.1 Emission Unit Nomenclature and Capacities

> Emissions represented in the application are based on an assumed 100 hr/yr of operation for maintenance and readiness testing of the engine.

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Construc. Date	Engine Rating (hp)	Annual Operating Hours
Dix Dam Crest Gate Emergency Generator	39	1	< 1970	40	100

14.2 Source Classification Codes

Emission Unit	KyEIS Source ID#	SCC	SCC Description	SCC Units
Dix Dam Crest Gate Emergency Generator	39	20201702	Gasoline (2-02-017), Reciprocating Engine (2-02-017-02)	1000 Gallons Gasoline Burned

14.3 Gasoline Properties

Gasoline fuel heating value:	89,000	Btu/gal	Information from fuel supplier. Expected range is from 76,000 to 89,000 Btu/gal.
Gasoline fuel density:	6.17	lb/gal	AP42 Appendix A (1/1995), pg. A-7
Maximum sulfur content:	0.03	ppm	Information from fuel supplier.

> The SCC for industrial gasoline engines is 20201702 with units of 1000 gallons. To convert emission factors in terms of lb/MMBtu to lb/1000 gallons, the approximate fuel heating value listed above is used.

14.4 Emission Factors Used

14.41 Criteria Pollutant Emissions

> AP42 Section 3.3 "Gasoline and Diesel Industrial Engines" (10/1996 edition) provides emission factors for criteria air pollutants and total organic compounds for gasoline-fired engines. Factors are expressed in terms of lb/hp-hr and lb/MMBtu. An average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used in AP42 to convert between emission factors based on power output and heat input. This consumption value inherently assumes an engine efficiency of 36.35%. The AP42 criteria pollutant emission factors are listed below:

Brake-Specific Fuel Consumption Value:	7000 Btu/hp-hr	AP42 Table 3.3-1 (10/1996), Footnote a
Engine efficiency assumption encompassed in this value:	36.35%	= 2,544.48 Btu/hp-hr / 7000 Btu/hp-hr

AP42 Table 3.3-1 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.011	1.571	4.989	139.86
CO	0.00696	0.994	3.157	88.49
SOX	0.000591	0.084	0.268	7.51
PM10	0.000721	0.103	0.327	9.17
TOC	0.02159	3.084	9.793	274.51

Sample Calculations (NOX): 1.571 lb/MMBtu = 0.011 lb/hp-hr / 7000 Btu/hp-hr * 1E6 Btu/MMBtu
4.989 g/hp-hr = 0.011 lb/hp-hr * 453.59 g/lb
139.86 lb/1000gal = 1.571 lb/MMBtu / 1E6 Btu/MMBtu x 89000 Btu/gal x 1000 gal / '1000gal'

> To take into account the lower sulfur content of the gasoline burned, for purposes of representing potential SO2 emissions from the engines, the AP42 factor from Table 3.4-1 for large diesel engines firing 15 ppm sulfur content fuel is adjusted downward by the ratio of the gasoline sulfur content (30 ppb) to 15 ppm

AP42 Table 3.4-1 SO2 factor for 15 ppm diesel fuel:	0.001515	lb/MMBtu	(Refer to Section 15.41 of emission calculations.)
Actual maximum sulfur content of gasoline used at Brown Station	0.03	ppm	
AP42 factor adjustment ratio	0.002		

SO2 Emissions Accounting for Sulfur Content

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
SO2	1.18E-06	1.69E-04	5.36E-04	1.50E-02

Sample Calculation (SO2): 0.000169 lb/MMBtu = 0.001515 lb/MMBtu x 0.002

> All PM emissions are conservatively assumed to be in the form of PM2.5. Thus, PM2.5 emissions are set equal to PM10.

> No HAP emission factors are provided in AP42 Section 3.3 for gasoline-fired industrial engines. Given the relatively small size of the Dix Dam generator engine, total HAPs from this source would be negligible and are not quantified.

14.5 Emissions

Engine Rating:	40	hp	
Equivalent heat input rate:	0.28	MMBtu/hr	= 40 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.00315	1000gal/hr	= 0.28 MMBtu/hr x 1E6 Btu/MMBtu / 89000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	139.86	AP42 Table 3.3-1	0.44	0.02
CO	88.49	AP42 Table 3.3-1	0.28	0.01
SO2	1.50E-02	AP42 Table 3.3-1; 30 ppb	4.73E-05	2.36E-06
PM10	9.17	AP42 Table 3.3-1	0.029	0.001
PM2.5	9.17	Equal to PM10	0.029	0.001
VOC	274.51	AP42 Table 3.3-1	0.864	0.043

15. Pre-NSPS Subpart IIII Emergency CI Engines (KyEIS ID#s 40-44)

> Documentation of capacities, emission factors, and emission calculations for pre NSPS Subpart IIII CI emergency generator and fire pump engines.

15.1 Emission Unit Nomenclature and Capacities

> Emissions represented in the application are based on an assumed 100 hr/yr of operation for maintenance and readiness testing of the

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Construc. Date	Engine Rating (hp)	Annual Operating Hours
Dix Dam Station Emergency Generator	40	1	< 2000	135	100
CT5 Emergency Generator	41	1	2000	308	100
CT6 Emergency Generator	42	1	1999	230	100
CT7 Emergency Generator	43	1	1999	230	100
CT Area Emergency Fire Pump Engine	44	1	1994	208	100

15.2 Source Classification Codes

Emission Unit	KyEIS Source ID#	SCC	SCC Description	SCC Units
Dix Dam Station Emergency Generator	40	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned
CT5 Emergency Generator	41	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned
CT6 Emergency Generator	42	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned
CT7 Emergency Generator	43	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned
CT Area Emergency Fire Pump Engine	44	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned

15.3 Diesel Fuel Properties

Diesel fuel heating value:	138,000	Btu/gal	Information from fuel supplier. Expected range is from 132,000 to 138,000 Btu/gal.
Diesel fuel density:	7.05	lb/gal	AP42 Appendix A (1/1995), pg. A-7
Maximum sulfur content:	15	ppm	Information from fuel supplier.

> The SCC for industrial diesel engines is 20200102 with units of 1000 gallons. To convert emission factors in terms of lb/MMBtu to lb/1000 gallons, the approximate fuel heating value listed above is used.

15.4 Emission Factors Used

15.41 Criteria Pollutant Emission Factors

> AP42 Section 3.3 "Gasoline and Diesel Industrial Engines" (10/1996 edition) provides emission factors for criteria air pollutants, total organic compounds, and HAPs from industrial engines. Factors are expressed in terms of lb/hp-hr and lb/MMBtu. An average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used in AP42 to convert between emission factors based on power output and heat input. This consumption value inherently assumes an engine efficiency of 36.35%. The AP42 criteria pollutant emission factors are listed below:

Brake-Specific Fuel Consumption Value:	7,000	Btu/hp-hr	AP42 Table 3.3-1 (10/1996), Footnote a
Engine efficiency assumption encompassed in this value:	36.35%	= 2,544.48 Btu/hp-hr / 7000 Btu/hp-hr	

AP42 Table 3.3-1 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.031	4.429	14.061	611.14
CO	0.00668	0.954	3.030	131.69
SOX	0.00205	0.293	0.930	40.41
PM10	0.00220	0.314	0.998	43.37
TOC (Exhaust + Crankcase)	0.0025141	0.359	1.140	49.56

Sample Calculations (NOX): 4.429 lb/MMBtu = 0.031 lb/hp-hr / 7000 Btu/hp-hr * 1E6 Btu/MMBtu
14.061 g/hp-hr = 0.031 lb/hp-hr * 453.59 g/lb
611.14 lb/1000gal = 4.429 lb/MMBtu / 1E6 Btu/MMBtu x 138000 Btu/gal x 1000 gal / '1000gal'

> To take into account the lower sulfur content of the diesel fuel burned, for purposes of representing potential SO2 emissions from the engines, the factor in AP42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO2 as a function of sulfur content.

AP42 Emission Factor for SO2 based on sulfur content:	1.01 S	lb/MMBtu (where S is the sulfur content in %)
Assumed maximum sulfur content in diesel oil:	15	ppm
Equivalent expressed in terms of percent:	0.0015	%

SO2 Emissions Based on Sulfur Content

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
SO2	0.0000106	0.001515	0.00481	0.2091

Sample Calculation (SO2): 0.001515 lb/MMBtu = 1.01 x 0.0015%

> All PM emissions are conservatively assumed to be in the form of PM2.5. Thus, PM2.5 emissions are set equal to PM10.

15.42 HAP Emission Factors

> Emission factors provided in AP42 Table 3.3-2 (10/1996 edition) are used to estimate emissions of HAPs from the engines. Factors are expressed in terms of lb/MMBtu. As with the criteria pollutants, an average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used to convert between emission factors based on power output and heat input.

AP42 Table 3.3-2 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
Acetaldehyde	5.37E-06	7.67E-04	2.44E-03	0.106
Acrolein	6.48E-07	9.25E-05	2.94E-04	0.013
Benzene	6.53E-06	9.33E-04	2.96E-03	0.129
1,3-Butadiene	2.74E-07	3.91E-05	1.24E-04	0.005
Formaldehyde	8.26E-06	1.18E-03	3.75E-03	0.163
Naphthalene	5.94E-07	8.48E-05	2.69E-04	0.012
Toluene	2.86E-06	4.09E-04	1.30E-03	0.056
Xylenes	2.00E-06	2.85E-04	9.05E-04	0.039

15.5 Emissions For Each Engine

15.51 Summary of Emissions from: Dix Dam Station Emergency Generator (EU40)

Engine Rating:	135	hp	
Equivalent heat input rate:	0.945	MMBtu/hr	= 135 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.00685	1000gal/hr	= 0.945 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	611.14	AP42 Table 3.3-1	4.19	0.21
CO	131.69	AP42 Table 3.3-1	0.90	0.05
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00143	0.00007
PM10	43.37	AP42 Table 3.3-1	0.297	0.015
PM2.5	43.37	Equal to PM10	0.297	0.015
VOC	49.56	AP42 Table 3.3-1	0.339	0.017
CO_2E	22,578	40 CFR 98 Subpart C	154.613	7.731
Acetaldehyde	0.106	AP42 Table 3.3-2	7.25E-04	3.62E-05
Acrolein	0.013	AP42 Table 3.3-2	8.74E-05	4.37E-06
Benzene	0.129	AP42 Table 3.3-2	8.82E-04	4.41E-05
1,3-Butadiene	0.005	AP42 Table 3.3-2	3.69E-05	1.85E-06
Formaldehyde	0.163	AP42 Table 3.3-2	1.12E-03	5.58E-05
Naphthalene	0.012	AP42 Table 3.3-2	8.01E-05	4.01E-06
Toluene	0.056	AP42 Table 3.3-2	3.87E-04	1.93E-05
Xylenes	0.039	AP42 Table 3.3-2	2.69E-04	1.35E-05

15.52 Summary of Emissions from: CT5 Emergency Generator (EU41)

Engine Rating:	308	hp	
Equivalent heat input rate:	2.156	MMBtu/hr	= 308 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.01562	1000gal/hr	= 2.156 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	611.14	AP42 Table 3.3-1	9.55	0.48
CO	131.69	AP42 Table 3.3-1	2.06	0.10
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00327	0.00016
PM10	43.37	AP42 Table 3.3-1	0.68	0.03
PM2.5	43.37	Equal to PM10	0.68	0.03
VOC	49.56	AP42 Table 3.3-1	0.77	0.04
CO_2E	22,578	40 CFR 98 Subpart C	352.75	17.64
Acetaldehyde	0.106	AP42 Table 3.3-2	1.65E-03	8.27E-05
Acrolein	0.013	AP42 Table 3.3-2	1.99E-04	9.97E-06
Benzene	0.129	AP42 Table 3.3-2	2.01E-03	1.01E-04
1,3-Butadiene	0.005	AP42 Table 3.3-2	8.43E-05	4.21E-06
Formaldehyde	0.163	AP42 Table 3.3-2	2.54E-03	1.27E-04
Naphthalene	0.012	AP42 Table 3.3-2	1.83E-04	9.14E-06
Toluene	0.056	AP42 Table 3.3-2	8.82E-04	4.41E-05
Xylenes	0.039	AP42 Table 3.3-2	6.14E-04	3.07E-05

15.53 Summary of Emissions from: CT6 Emergency Generator (EU42)

Engine Rating:	230	hp	
Equivalent heat input rate:	1.61	MMBtu/hr	= 230 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.01167	1000gal/hr	= 1.61 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	611.14	AP42 Table 3.3-1	7.13	0.36
CO	131.69	AP42 Table 3.3-1	1.54	0.08
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00244	0.00012
PM10	43.37	AP42 Table 3.3-1	0.51	0.03
PM2.5	43.37	Equal to PM10	0.51	0.03
VOC	49.56	AP42 Table 3.3-1	0.58	0.03
CO_2E	22,578	40 CFR 98 Subpart C	263.41	13.17
Acetaldehyde	0.106	AP42 Table 3.3-2	1.23E-03	6.17E-05
Acrolein	0.013	AP42 Table 3.3-2	1.49E-04	7.45E-06
Benzene	0.129	AP42 Table 3.3-2	1.50E-03	7.51E-05
1,3-Butadiene	0.005	AP42 Table 3.3-2	6.30E-05	3.15E-06
Formaldehyde	0.163	AP42 Table 3.3-2	1.90E-03	9.50E-05
Naphthalene	0.012	AP42 Table 3.3-2	1.37E-04	6.83E-06
Toluene	0.056	AP42 Table 3.3-2	6.58E-04	3.29E-05
Xylenes	0.039	AP42 Table 3.3-2	4.59E-04	2.29E-05

15.54 Summary of Emissions from: CT7 Emergency Generator (EU43)

Engine Rating:	230	hp	
Equivalent heat input rate:	1.61	MMBtu/hr	= 230 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.01167	1000gal/hr	= 1.61 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	611.14	AP42 Table 3.3-1	7.13	0.36
CO	131.69	AP42 Table 3.3-1	1.54	0.08
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00244	0.00012
PM10	43.37	AP42 Table 3.3-1	0.51	0.03
PM2.5	43.37	Equal to PM10	0.51	0.03
VOC	49.56	AP42 Table 3.3-1	0.58	0.03
CO_2E	22,578	40 CFR 98 Subpart C	263.41	13.17
Acetaldehyde	0.106	AP42 Table 3.3-2	1.23E-03	6.17E-05
Acrolein	0.013	AP42 Table 3.3-2	1.49E-04	7.45E-06
Benzene	0.129	AP42 Table 3.3-2	1.50E-03	7.51E-05
1,3-Butadiene	0.005	AP42 Table 3.3-2	6.30E-05	3.15E-06
Formaldehyde	0.163	AP42 Table 3.3-2	1.90E-03	9.50E-05
Naphthalene	0.012	AP42 Table 3.3-2	1.37E-04	6.83E-06
Toluene	0.056	AP42 Table 3.3-2	6.58E-04	3.29E-05
Xylenes	0.039	AP42 Table 3.3-2	4.59E-04	2.29E-05

15.55 Summary of Emissions from: CT Area Emergency Fire Pump Engine (EU44)

Engine Rating:	208	hp	
Equivalent heat input rate:	1.456	MMBtu/hr	= 208 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.01055	1000gal/hr	= 1.456 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	611.14	AP42 Table 3.3-1	6.45	0.32
CO	131.69	AP42 Table 3.3-1	1.39	0.07
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00221	0.00011
PM10	43.37	AP42 Table 3.3-1	0.46	0.02
PM2.5	43.37	Equal to PM10	0.46	0.02
VOC	49.56	AP42 Table 3.3-1	0.52	0.03
CO_2E	22,578	40 CFR 98 Subpart C	238.22	11.91
Acetaldehyde	0.106	AP42 Table 3.3-2	1.12E-03	5.58E-05
Acrolein	0.013	AP42 Table 3.3-2	1.35E-04	6.73E-06
Benzene	0.129	AP42 Table 3.3-2	1.36E-03	6.79E-05
1,3-Butadiene	0.005	AP42 Table 3.3-2	5.69E-05	2.85E-06
Formaldehyde	0.163	AP42 Table 3.3-2	1.72E-03	8.59E-05
Naphthalene	0.012	AP42 Table 3.3-2	1.23E-04	6.17E-06
Toluene	0.056	AP42 Table 3.3-2	5.96E-04	2.98E-05
Xylenes	0.039	AP42 Table 3.3-2	4.15E-04	2.07E-05

16. Steam Plant Area Fire Pump Engines (KyEIS ID#s 45-46)

> Documentation of capacities, emission factors, and emission calculations for steam plant emergency fire pump engines.

16.1 Emission Unit Nomenclature and Capacities

> The fire pump engines were manufactured in April 2007 and thus are Model Year 2007 engines. They were accepted from the contractor and initiated service as fire pump engines in February 2008.

> The fire pump engines are subject to NSPS Subpart IIII. Pursuant to 60.4211(e), as emergency stationary ICE, the engines can be operated for up to 100 hr/yr for maintenance checks and readiness testing. There is no limit on use of the engines in emergency situations. Emissions represented in the application are based on an assumed 100 hr/yr of operation.

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Manufact. Date	Startup Date	Engine Rating (hp)	Annual Operating Hours
Emergency Steam Plant Fire Pump Engine #1	45	1	4/2007	2/2008	375	100
Emergency Steam Plant Fire Pump Engine #2	46	1	4/2007	2/2008	375	100

16.2 Source Classification Codes

Emission Unit	KyEIS Source ID#	SCC	SCC Description	SCC Units
Emergency Steam Plant Fire Pump Engine #1	45	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned
Emergency Steam Plant Fire Pump Engine #2	46	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned

16.3 Diesel Fuel Properties

Diesel fuel heating value:	138,000	Btu/gal	Information from fuel supplier. Expected range is from 132,000 to 138,000 Btu/gal.
Diesel fuel density:	7.05	lb/gal	AP42 Appendix A (1/1995), pg. A-7
Maximum sulfur content:	15	ppm	Information from fuel supplier.

> The SCC for industrial diesel engines is 20200102 with units of 1000 gallons. To convert emission factors in terms of lb/MMBtu to lb/1000 gallons, the approximate fuel heating value listed above is used.

> Currently, the sulfur content in the diesel oil used in the engines is limited by 60.4207(a) to 500 ppm. Beginning October 1, 2010, the sulfur content will be limited by 60.4207(b) to 15 ppm. Based on current fuel specifications in place at Brown Station, a value of 15 ppm has been used for calculations.

16.4 Emission Factors Used

16.41 Criteria Pollutant Emission Factors

> AP42 Section 3.3 "Gasoline and Diesel Industrial Engines" (10/1996 edition) provides emission factors for criteria air pollutants, total organic compounds, and HAPs from industrial engines. Factors are expressed in terms of lb/hp-hr and lb/MMBtu. An average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used in AP42 to convert between emission factors based on power output and heat input. This consumption value inherently assumes an engine efficiency of 36.35%. The AP42 criteria pollutant emission factors are listed below:

Brake-Specific Fuel Consumption Value:	7,000	Btu/hp-hr	AP42 Table 3.3-1 (10/1996), Footnote a
Engine efficiency assumption encompassed in this value:	36.35%	= 2,544.48 Btu/hp-hr / 7000 Btu/hp-hr	

AP42 Table 3.3-1 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.031	4.429	14.061	611.14
CO	0.00668	0.954	3.030	131.69
SOX	0.00205	0.293	0.930	40.41
PM10	0.00220	0.314	0.998	43.37
TOC (Exhaust + Crankcase)	0.0025141	0.359	1.140	49.56

Sample Calculations (NOX):
4.429 lb/MMBtu = 0.031 lb/hp-hr / 7000 Btu/hp-hr * 1E6 Btu/MMBtu
14.061 g/hp-hr = 0.031 lb/hp-hr * 453.59 g/lb
611.14 lb/1000gal = 4.429 lb/MMBtu / 1E6 Btu/MMBtu x 138000 Btu/gal x 1000 gal / '1000gal'

> Pursuant to 40 CFR 60.4205(c), the fire pump engines must meet the emission standards in Table 4 of Subpart IIII. Therefore, potential emissions from the engines for those pollutants for which standards are established have been used in lieu of those in AP42. The Subpart IIII emission factors are listed below.

NSPS Subpart IIII Standards

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NMHC + NOX	0.01720	2.457	7.8	339.01
CO	0.00573	0.819	2.6	113.00
PM	0.00088	0.126	0.4	17.39

> A separate VOC and NOX emission factor that conforms to the Subpart IIII requirements can be derived based on the ratio of the TOC to NOX factor in AP42 Table 3.3-1 (10/1996 edition).

Sum of AP42 NOX and TOC emission factors:	15.202	g/hp-hr	= 14.061 + 1.14
Ratio of TOC factor to sum of NOX and TOC factors:	0.075		= 1.14 / 15.202
Ratio of NOX factor to sum of NOX and TOC factors:	0.925		= 14.061 / 15.202

> Approximate Subpart IIII equivalent NOX and VOC factors are shown below:

Equivalent NSPS Subpart IIII Standards

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.0159	2.272	7.215	313.58
VOC	0.0013	0.184	0.585	25.43

Sample Calculation (NOX): 7.215 g/hp-hr = 0.925 x 7.8 g/hp-hr

> To take into account the lower sulfur content of the diesel fuel burned, for purposes of representing potential SO2 emissions from the engines, the factor in AP42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO2 as a function of sulfur content.

AP42 Emission Factor for SO2 based on sulfur content:	1.01 S	lb/MMBtu (where S is the sulfur content in %)
Assumed maximum sulfur content in diesel oil:	15	ppm
Equivalent expressed in terms of percent:	0.0015	%

SO2 Emissions Based on Sulfur Content

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
SO2	0.0000106	0.001515	0.00481	0.2091

Sample Calculation (SO2): 0.001515 lb/MMBtu = 1.01 x 0.0015%

> A comparison of the Subpart IIII emission factors with those in AP42 Table 3.3-1 (10/1996 edition) is provided in the following table. The CO factor from Subpart IIII is only slightly less than AP42. The NOX, PM10 and VOC factors are about half of AP42. The SO2 factor, based on 15 ppm, is well below the AP42 factor. For emission calculations presented in this application, the Subpart IIII factors are used.

	AP42 (g/hp-hr)	Subpart IIII (g/hp-hr)	Ratio of Subpart IIII to AP42
NOX	14.0613	7.215	0.513
CO	3.0300	2.600	0.858
SO2	0.9299	0.0048	0.005
PM10	0.9979	0.400	0.401
VOC	1.1404	0.585	0.513

> All PM emissions are conservatively assumed to be in the form of PM2.5. Thus, PM2.5 emissions are set equal to PM10.

16.42 HAP Emission Factors

> Emission factors provided in AP42 Table 3.3-2 (10/1996 edition) are used to estimate emissions of HAPs from the engines. Factors are expressed in terms of lb/MMBtu. As with the criteria pollutants, an average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used to convert between emission factors based on power output and heat input.

AP42 Table 3.3-2 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
Acetaldehyde	5.37E-06	7.67E-04	2.44E-03	0.106
Acrolein	6.48E-07	9.25E-05	2.94E-04	0.013
Benzene	6.53E-06	9.33E-04	2.96E-03	0.129
1,3-Butadiene	2.74E-07	3.91E-05	1.24E-04	0.005
Formaldehyde	8.26E-06	1.18E-03	3.75E-03	0.163
Naphthalene	5.94E-07	8.48E-05	2.69E-04	0.012
Toluene	2.86E-06	4.09E-04	1.30E-03	0.056
Xylenes	2.00E-06	2.85E-04	9.05E-04	0.039

16.5 Emissions For Each Engine

16.51 Summary of Emissions from Emergency Fire Pump Engines #1 and #2 (Each)

Engine Rating:	375	hp	
Equivalent heat input rate:	2.625	MMBtu/hr	= 375 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.01902	1000gal/hr	= 2.625 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	313.58	Subpart IIII- 60.4205(c)	5.96	0.30
CO	113.00	Subpart IIII- 60.4205(c)	2.15	0.11
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00398	0.00020
PM10	17.39	Subpart IIII- 60.4205(c)	0.331	0.017
PM2.5	17.39	Equal to PM10	0.331	0.017
VOC	25.43	Subpart IIII- 60.4205(c)	0.484	0.024
CO_2E	22,578	40 CFR 98 Subpart C	429.481	21.474
Acetaldehyde	0.106	AP42 Table 3.3-2	2.01E-03	1.01E-04
Acrolein	0.013	AP42 Table 3.3-2	2.43E-04	1.21E-05
Benzene	0.129	AP42 Table 3.3-2	2.45E-03	1.22E-04
1,3-Butadiene	0.005	AP42 Table 3.3-2	1.03E-04	5.13E-06
Formaldehyde	0.163	AP42 Table 3.3-2	3.10E-03	1.55E-04
Naphthalene	0.012	AP42 Table 3.3-2	2.23E-04	1.11E-05
Toluene	0.056	AP42 Table 3.3-2	1.07E-03	5.37E-05
Xylenes	0.039	AP42 Table 3.3-2	7.48E-04	3.74E-05

17. Emergency Quench Water Pump Engines (KyEIS ID#s 47-48)

> Documentation of capacities, emission factors, and emission calculations for emergency quench water pump engines associated with the FGD system.

17.1 Emission Unit Nomenclature and Capacities

> The emergency quench water pump engines were manufactured in April 2007 and thus are Model Year 2007 engines. They will be commissioned and startup with the FGD system in early 2010.

> The emergency quench water engines are subject to NSPS Subpart IIII. Pursuant to 60.4211(e), as emergency stationary ICE, the engines can be operated for up to 100 hr/yr for maintenance checks and readiness testing. There is no limit on use of the engines in emergency situations. Emissions represented in the application are based on an assumed 100 hr/yr of operation.

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Manufact. Date	Startup Date	Engine Rating (hp)	Annual Operating Hours
Emergency Quench Water Pump Engine #1	47	1	4/2007	2010	485	100
Emergency Tier II 1220 HP Diesel RICE	52	1	4/2007	2010	485	100

17.2 Source Classification Codes

Emission Unit	KyEIS Source ID#	SCC	SCC Description	SCC Units
Emergency Quench Water Pump Engine #1	47	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned
Emergency Tier II 1220 HP Diesel RICE	52	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned

17.3 Diesel Fuel Properties

Diesel fuel heating value:	138,000	Btu/gal	Information from fuel supplier. Expected range is from 132,000 to 138,000 Btu/gal.
Diesel fuel density:	7.05	lb/gal	AP42 Appendix A (1/1995), pg. A-7
Maximum sulfur content:	15	ppm	Information from fuel supplier.

> The SCC for industrial diesel engines is 20200102 with units of 1000 gallons. To convert emission factors in terms of lb/MMBtu to lb/1000 gallons, the approximate fuel heating value listed above is used.

> Currently, the sulfur content in the diesel oil used in the engines is limited by 60.4207(a) to 500 ppm. Beginning October 1, 2010, the sulfur content will be limited by 60.4207(b) to 15 ppm. Based on current fuel specifications in place at Brown Station, a value of 15 ppm has been used for calculations.

17.4 Emission Factors Used

17.41 Criteria Pollutant Emission Factors

> AP42 Section 3.3 "Gasoline and Diesel Industrial Engines" (10/1996 edition) provides emission factors for criteria air pollutants, total organic compounds, and HAPs from industrial engines. Factors are expressed in terms of lb/hp-hr and lb/MMBtu. An average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used in AP42 to convert between emission factors based on power output and heat input. This consumption value inherently assumes an engine efficiency of 36.35%. The AP42 criteria pollutant emission factors are listed below:

Brake-Specific Fuel Consumption Value:	7,000	Btu/hp-hr	AP42 Table 3.3-1 (10/1996), Footnote a
Engine efficiency assumption encompassed in this value:	36.35%	= 2,544.48 Btu/hp-hr / 7000 Btu/hp-hr	

AP42 Table 3.3-1 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.031	4.429	14.061	611.14
CO	0.00668	0.954	3.030	131.69
SOX	0.00205	0.293	0.930	40.41
PM10	0.00220	0.314	0.998	43.37
TOC (Exhaust + Crankcase)	0.0025141	0.359	1.140	49.56

Sample Calculations (NOX): 4.429 lb/MMBtu = 0.031 lb/hp-hr / 7000 Btu/hp-hr * 1E6 Btu/MMBtu
14.061 g/hp-hr = 0.031 lb/hp-hr * 453.59 g/lb
611.14 lb/1000gal = 4.429 lb/MMBtu / 1E6 Btu/MMBtu x 138000 Btu/gal x 1000 gal / '1000gal'

> Pursuant to 40 CFR 60.4205(b), as emergency stationary CI ICE with a displacement per cylinder less than 30 L, the emergency quench water engines must comply with the emission standards for nonroad CI engines in 40 CFR 60.4202. 40 CFR 60.4202(c) cross-references 40 CFR 94.8. The applicable emission standards from 40 CFR 94.8 are listed below.

NSPS Subpart IIII Standards

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NMHC + NOX	0.01720	2.457	7.8	339.01
CO	0.01102	1.575	5	217.31
PM	0.00060	0.085	0.27	11.73

> A separate VOC and NOX emission factor that conforms to the Subpart IIII requirements can be derived based on the ratio of the TOC to NOX factor in AP42 Table 3.3-1 (10/1996 edition).

Sum of AP42 NOX and TOC emission factors:	15.202	g/hp-hr	= 14.061 + 1.14
Ratio of TOC factor to sum of NOX and TOC factors:	0.075		= 1.14 / 15.202
Ratio of NOX factor to sum of NOX and TOC factors:	0.925		= 14.061 / 15.202

> Approximate Subpart IIII equivalent NOX and VOC factors are shown below:

Equivalent NSPS Subpart IIII Standards

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.0159	2.272	7.215	313.58
VOC	0.0013	0.184	0.585	25.43

Sample Calculation (NOX): 7.215 g/hp-hr = 0.925 x 7.8 g/hp-hr

> To take into account the lower sulfur content of the diesel fuel burned, for purposes of representing potential SO2 emissions from the engines, the factor in AP42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO2 as a function of sulfur content.

AP42 Emission Factor for SO2 based on sulfur content:	1.01 S	lb/MMBtu (where S is the sulfur content in %)
Assumed maximum sulfur content in diesel oil:	15	ppm
Equivalent expressed in terms of percent:	0.0015	%

SO2 Emissions Based on Sulfur Content

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
SO2	0.0000106	0.001515	0.00481	0.2091

Sample Calculation (SO2): 0.001515 lb/MMBtu = 1.01 x 0.0015%

> A comparison of the Subpart IIII emission factors with those in AP42 Table 3.3-1 (10/1996 edition) is provided in the following table. The CO factor from Subpart IIII is slightly higher than AP42. The NOX, PM10 and VOC factors are about half of AP42. The SO2 factor, based on 15 ppm, is well below the AP42 factor. For emission calculations presented in this application, the Subpart IIII factors are used.

	AP42 (g/hp-hr)	Subpart IIII (g/hp-hr)	Ratio of Subpart IIII to AP42
NOX	14.0613	7.215	0.513
CO	3.0300	5.000	1.650
SO2	0.9299	0.0048	0.005
PM10	0.9979	0.270	0.271
VOC	1.1404	0.585	0.513

> All PM emissions are conservatively assumed to be in the form of PM2.5. Thus, PM2.5 emissions are set equal to PM10.

17.42 HAP Emission Factors

> Emission factors provided in AP42 Table 3.3-2 (10/1996 edition) are used to estimate emissions of HAPs from the engines. Factors are expressed in terms of lb/MMBtu. As with the criteria pollutants, an average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used to convert between emission factors based on power output and heat input.

AP42 Table 3.3-2 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
Acetaldehyde	5.37E-06	7.67E-04	2.44E-03	0.106
Acrolein	6.48E-07	9.25E-05	2.94E-04	0.013
Benzene	6.53E-06	9.33E-04	2.96E-03	0.129
1,3-Butadiene	2.74E-07	3.91E-05	1.24E-04	0.005
Formaldehyde	8.26E-06	1.18E-03	3.75E-03	0.163
Naphthalene	5.94E-07	8.48E-05	2.69E-04	0.012
Toluene	2.86E-06	4.09E-04	1.30E-03	0.056
Xylenes	2.00E-06	2.85E-04	9.05E-04	0.039

17.5 Emissions For Each Engine

17.51 Summary of Emissions from Emergency Quench Water Engines #1 and #2 (Each)

Engine Rating:	485	hp	
Equivalent heat input rate:	3.395	MMBtu/hr	= 485 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.02460	1000gal/hr	= 3.395 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	313.58	Subpart IIII- 60.4205(b)	7.71	0.39
CO	217.31	Subpart IIII- 60.4205(b)	5.35	0.27
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00514	0.00026
PM10	11.73	Subpart IIII- 60.4205(b)	0.29	0.014
PM2.5	11.73	Equal to PM10	0.29	0.014
VOC	25.43	Subpart IIII- 60.4205(b)	0.63	0.031
CO_2E	22,578	40 CFR 98 Subpart C	555.46	27.773
Acetaldehyde	0.106	AP42 Table 3.3-2	2.60E-03	1.30E-04
Acrolein	0.013	AP42 Table 3.3-2	3.14E-04	1.57E-05
Benzene	0.129	AP42 Table 3.3-2	3.17E-03	1.58E-04
1,3-Butadiene	0.005	AP42 Table 3.3-2	1.33E-04	6.64E-06
Formaldehyde	0.163	AP42 Table 3.3-2	4.01E-03	2.00E-04
Naphthalene	0.012	AP42 Table 3.3-2	2.88E-04	1.44E-05
Toluene	0.056	AP42 Table 3.3-2	1.39E-03	6.94E-05
Xylenes	0.039	AP42 Table 3.3-2	9.68E-04	4.84E-05

18. Emergency Tier II 752 HP Diesel RICE

> Documentation of capacities, emission factors, and emission calculations for emergency RICE engine

18.1 Emission Unit Nomenclature and Capacities

> The emergency was manufactured in 2009 and placed in service in 2010.

> The emergency RICE is subject to NSPS Subpart IIII. Pursuant to 60.4211(e), as emergency stationary ICE, the engines can be operated for up to 100 hr/yr for maintenance checks and readiness testing. There is no limit on use of the engines in emergency situations. Emissions represented in the application are based on an assumed 100 hr/yr of operation.

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Manufact. Date	Startup Date	Engine Rating (hp)	Annual Operating Hours
Emergency Tier II 752 HP Diesel RICE	49	1	2009	2010	752	100

18.2 Source Classification Codes

Emission Unit	KyEIS Source ID#	SCC	SCC Description	SCC Units
Emergency Tier II 752 HP Diesel RICE	49	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned

18.3 Diesel Fuel Properties

Diesel fuel heating value:	138,000	Btu/gal	Information from fuel supplier. Expected range is from 132,000 to 138,000 Btu/gal.
Diesel fuel density:	7.05	lb/gal	AP42 Appendix A (1/1995), pg. A-7
Maximum sulfur content:	15	ppm	Information from fuel supplier.

> The SCC for industrial diesel engines is 20200102 with units of 1000 gallons. To convert emission factors in terms of lb/MMBtu to lb/1000 gallons, the approximate fuel heating value listed above is used.

> Sulfur content in the diesel oil used in the engines is based on the October 1, 2010, the sulfur limited (60.4207(b)) of 15 ppm.

18.4 Emission Factors Used

18.41 Criteria Pollutant Emission Factors

> AP42 Section 3.4 "Gasoline and Diesel Industrial Engines" (10/1996 edition) provides emission factors for criteria air pollutants, total organic compounds, and HAPs from industrial engines. Factors are expressed in terms of lb/hp-hr and lb/MMBtu. An average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used in AP42 to convert between emission factors based on power output and heat input. This consumption value inherently assumes an engine efficiency of 36.35%. The AP42 criteria pollutant emission factors are listed below:

Brake-Specific Fuel Consumption Value:	7,000	Btu/hp-hr	AP42 Table 3.3-1 (10/1996), Footnote a
Engine efficiency assumption encompassed in this value:	36.35%	= 2,544.48 Btu/hp-hr / 7000 Btu/hp-hr	

AP42 Table 3.4-1 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.024	3.429	10.886	473.14
CO	0.00550	0.786	2.495	108.43
SOX	0.000012	0.002	0.005	0.24
PM10	0.00070	0.100	0.318	13.80
TOC (Exhaust + Crankcase)	0.0007050	0.101	0.320	13.90

Sample Calculations (NOX):
3.429 lb/MMBtu = 0.024 lb/hp-hr / 7000 Btu/hp-hr * 1E6 Btu/MMBtu
10.886 g/hp-hr = 0.024 lb/hp-hr * 453.59 g/lb
473.14 lb/1000gal = 3.429 lb/MMBtu / 1E6 Btu/MMBtu x 138000 Btu/gal x 1000 gal / '1000gal'

> Pursuant to 40 CFR 60.4205(b), as emergency stationary CI ICE with a displacement per cylinder less than 30 L and 2007bmodel and newer, the emergency RICE must comply with the emission standards for nonroad CI engines in 40 CFR 60.4202. 40 CFR 60.4202(c) cross-references 40 CFR 94.8. The applicable emission standards from 40 CFR 94.8 are listed below.

NSPS Subpart IIII Standards

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NMHC + NOX	0.01411	2.016	6.4	278.16
CO	0.00772	1.102	3.5	152.12
PM	0.00044	0.063	0.2	8.69

> A separate VOC and NOX emission factor that conforms to the Subpart IIII requirements can be derived based on the ratio of the TOC to NOX factor in AP42 Table 3.4 (10/1996 edition).

Sum of AP42 NOX and TOC emission factors:	11.206	g/hp-hr	= 10.886 + 0.32
Ratio of TOC factor to sum of NOX and TOC factors:	0.029		= 0.32 / 11.206
Ratio of NOX factor to sum of NOX and TOC factors:	0.971		= 10.886 / 11.206

> Approximate Subpart IIII equivalent NOX and VOC factors are shown below:

Equivalent NSPS Subpart IIII Standards

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.0137	1.958	6.217	270.22
VOC	0.0004	0.058	0.183	7.94

Sample Calculation (NOX): 6.217 g/hp-hr = 0.971 x 6.4 g/hp-hr

> To take into account the lower sulfur content of the diesel fuel burned, for purposes of representing potential SO2 emissions from the engines, the factor in AP42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO2 as a function of sulfur content.

AP42 Emission Factor for SO2 based on sulfur content:	1.01 S	lb/MMBtu (where S is the sulfur content in %)
Assumed maximum sulfur content in diesel oil:	15	ppm
Equivalent expressed in terms of percent:	0.0015	%

SO2 Emissions Based on Sulfur Content

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
SO2	0.0000106	0.001515	0.00481	0.2091

Sample Calculation (SO2): 0.001515 lb/MMBtu = 1.01 x 0.0015%

> A comparison of the Subpart IIII emission factors with those in AP42 Table 3.4 (10/1996 edition) is provided in the following table. The CO factor from Subpart IIII is slightly higher than AP42. The NOX, PM10 and VOC factors are about half of AP42. The SO2 factor, based on 15 ppm, is well below the AP42 factor. For emission calculations presented in this application, the Subpart IIII factors are used.

	AP42 (g/hp-hr)	Subpart IIII (g/hp-hr)	Ratio of Subpart IIII to AP42
NOX	10.8862	6.217	0.571
CO	2.4947	3.500	1.403
SO2	0.0055	0.0048	0.876
PM10	0.3175	0.200	0.630
VOC	0.3198	0.183	0.571

> All PM emissions are conservatively assumed to be in the form of PM2.5. Thus, PM2.5 emissions are set equal to PM10.

18.42 HAP Emission Factors

> Emission factors provided in AP42 Tables 3.4 (10/1996 edition) are used to estimate emissions of HAPs from the engines. Factors are expressed in terms of lb/MMBtu. As with the criteria pollutants, an average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used to convert between emission factors based on power output and heat input.

AP42 Table 3.4 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
Acetaldehyde	5.37E-06	7.67E-04	2.44E-03	0.106
Acrolein	6.48E-07	9.25E-05	2.94E-04	0.013
Benzene	6.53E-06	9.33E-04	2.96E-03	0.129
1,3-Butadiene	2.74E-07	3.91E-05	1.24E-04	0.005
Formaldehyde	8.26E-06	1.18E-03	3.75E-03	0.163
Naphthalene	5.94E-07	8.48E-05	2.69E-04	0.012
Toluene	2.86E-06	4.09E-04	1.30E-03	0.056
Xylenes	2.00E-06	2.85E-04	9.05E-04	0.039

18.5 Emissions For Engine

18.51 Summary of Emissions from 752 HP RICE

Engine Rating:	752	hp	
Equivalent heat input rate:	5.264	MMBtu/hr	= 752 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.03814	1000gal/hr	= 5.264 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	270.22	Subpart IIII- 60.4205(b)	10.31	0.52
CO	152.12	Subpart IIII- 60.4205(b)	5.80	0.29
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.00797	0.00040
PM10	8.69	Subpart IIII- 60.4205(b)	0.33	0.017
PM2.5	8.69	Equal to PM10	0.33	0.017
VOC	7.94	Subpart IIII- 60.4205(b)	0.30	0.015
CO_2E	22,578	40 CFR 98 Subpart C	861.25	43.063
Acetaldehyde	0.106	AP42 Table 3.4-3	4.04E-03	2.02E-04
Acrolein	0.013	AP42 Table 3.4-3	4.87E-04	2.43E-05
Benzene	0.129	AP42 Table 3.4-3	4.91E-03	2.46E-04
1,3-Butadiene	0.005	AP42 Table 3.4-3	2.06E-04	1.03E-05
Formaldehyde	0.163	AP42 Table 3.4-3	6.21E-03	3.11E-04
Naphthalene	0.012	AP42 Table 3.4-3	4.46E-04	2.23E-05
Toluene	0.056	AP42 Table 3.4-3	2.15E-03	1.08E-04
Xylenes	0.039	AP42 Table 3.4-3	1.50E-03	7.50E-05

19. New Ash Landfill & Haul Trucks (PM Fugitive Emissions)

PM emissions due to transporting bottom ash, fly ash and gypsum via trucks and front end loaders, both from the processing areas and at the landfill, are documented in this section.

Fugitive PM emissions due to vehicle movement on plant roads are estimated using methodologies of AP42 Section 13.2.1 for paved roads (1/2011 Edition) and AP42 Section 13.2.2 for unpaved roads (11/2006 Edition).

SCC code 30502504

19.1 Weights for Transport Equipment Used in Emission Calculations

Transport Vehicle Type	Empty Weight (tons)	Full Weight (tons)	Material Carried per Load (tons)
Landfill Haul Trucks	24	66.5	42.5
Front End Loaders	27.7	33.7	6

19.2 Maximum Volume of Material Transported in Each Route

Asuumes that all bottom ash, fly ash and gypsum generated at E.W. Brown are to be landfilled.

Transport Vehicle Type	Maximum Volume (ton/yr)	Basis
Total volume of bottom ash processed	45,120	
Total volume of fly ash processed	180,500	
Total volume of gypsum processed	351,800	
Total materials sent to landfill	577,420	= 351800 ton/yr + 180500 ton/yr + 45120 ton/yr

19.3 Vehicle Miles Traveled Per Year for Each Truck/Vehicle Route

Transport Operation	Maximum Annual Volume (ton/yr)	Annual Trips (trips/yr)	Paved Distance Per Trip (mi)	Unpaved Distance Per Trip (mi)	VMT Paved Distance Traveled (VMT/yr)	VMT Unpaved Distance Traveled (VMT/yr)
Bottom Ash Transport						
Full Front End Loader from Bottom Ash Area to Truck	45,120	7,520	0.1		752	
Empty Front End Loader from Truck to Bottom Ash Area		7,520	0.1		752	
Fly Ash Transport						
Full Front End Loader from Fly Ash Area to Truck	180,500	30,083	0.1		3,008	
Empty Front End Loader from Truck to Fly Ash Area		30,083	0.1		3,008	
Gypsum Transport						
Full Front End Loader from Gypsum Stack Area to Truck	351,800	58,633	0.1		5,863	
Empty Front End Loader from Truck to Gypsum Stack Area		58,633	0.1		5,863	
					19,247	
Landfill Operations (Haul Trucks) (EU ID#: 50)						
Travel of Heavy Equipment In/Around Landfill		365	0.0	1.0	0	365
Full Bottom Ash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	45,120	1,062	0.0	0.56	0	597
Empty Bottom Ash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area		1,062	0.0	0.56	0	597
Full Flyash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	180,500	4,247	0.0	0.56	0	2,389
Empty Flyash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area		4,247	0.0	0.56	0	2,389
Full Gyspum Trucks from Gypsum Stack Area to Active Area of Landfill	351,800	8,278	0.0	0.63	0	5,252
Empty Gypsum Truck Returning from Active Landfill Site to Gyspum Stack Area		8,278	0.0	0.63	0	5,252
	TOTAL TRIPS	27,538		TOTAL VMT		16,841

19.4 Unpaved Road Emission Factors

The methodology presented in AP-42 Section 13.2.2 (11/2006) is used to derive fugitive PM emission factors for truck traffic on unpaved road surfaces within the plant.

The following emission factor equation applies: (Equations 1a and 2 in AP42 13.2.2)

$E\ (lb/VMT) = [(k)(s/12)^a(W/3)^b]((365-P)/365)$

where:			PM	PM10	PM2.5	
k	=	Particle Size Multiplier (lb/VMT)	4.9	1.5	0.15	AP42 Table 13.2.2-2
a	=	Constant	0.7	0.9	0.9	AP42 Table 13.2.2-2
b	=	Constant	0.45	0.45	0.45	AP42 Table 13.2.2-2

s	=	Surface Material Silt Content (%)	3.9	Value used by EPA in the 1999 National Emissions Inventory for unpaved roads in Kentucky.
P	=	Days with Precipitation	129	Average of 2005-2009 surface data at NWS Station 72421 (CVG Airport in Boone County).

A control efficiency is applied to account for road maintenance and dust suppression methods such as periodic watering.

Transport Operation	Truck Weight (tons)	Control Efficiency (%)	PM Factor (lb/VMT)	PM10 Factor (lb/VMT)	PM2.5 Factor (lb/VMT)
Landfill Operations (Haul Trucks) (EU ID#: 50)					
Travel of Heavy Equipment In/Around Landfill	33.7	70%	1.285	0.314	0.031
Full Bottom Ash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	66.5	70%	1.745	0.427	0.043
Empty Bottom Ash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area	24	70%	1.103	0.270	0.027
Full Flyash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	66.5	70%	1.745	0.427	0.043
Empty Flyash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area	24	70%	1.103	0.270	0.027
Full Gyspum Trucks from Gypsum Stack Area to Active Area of Landfill	66.5	70%	1.745	0.427	0.043
Empty Gypsum Truck Returning from Active Landfill Site to Gyspum Stack Area	24	70%	1.103	0.270	0.027

19.5 Paved Road Emission Factors

The methodology presented in AP-42 Section 13.2.1 (1/2011) was used to derive fugitive PM emission factors for truck traffic on paved road surfaces within the plant.
The following emission factor equation applies: (Equation 2 in AP43 13.2.1)

$E\ (lb/VMT) = (k)(sL/2)^{0.91}(W)^{1.02}(1-P/4N)$

where:			PM	PM10	PM2.5	
k	=	Particle Size Multiplier (lb/VMT)	0.011	0.0022	0.00054	AP42 Table 13.2.1-1

sL	=	Silt Loading (g/m2)	3	AP42 Table 13.2.1-3 (1/2011); Selected based on range of values for quarries in Table 13.2.1-3.
P	=	Days with Precipitation	129	Average of 2005-2009 surface data at NWS Station 72421 (CVG Airport in Boone County).
N	=	Number of days in averaging period	365	Days per year

A control efficiency is applied to account for road maintenance and dust suppression methods such as periodic watering.

Transport Operation	KyEIS Process ID#	Truck Weight (tons)	Control Efficiency (%)	PM Factor (lb/VMT)	PM10 Factor (lb/VMT)	PM2.5 Factor (lb/VMT)
Bottom Ash Transport						
Full Front End Loader from Bottom Ash Area to Truck	4	33.7	70%	0.157	0.031	0.008
Empty Front End Loader from Truck to Bottom Ash Area	1	27.7	70%	0.129	0.026	0.006
Fly Ash Transport						
Full Front End Loader from Fly Ash Area to Truck	2	33.7	70%	0.157	0.031	0.008
Empty Front End Loader from Truck to Fly Ash Area	5	27.7	70%	0.129	0.026	0.006
Gypsum Transport						
Full Front End Loader from Gypsum Stack Area to Truck	6	33.7	70%	0.157	0.031	0.008
Empty Front End Loader from Truck to Gypsum Stack Area	3	27.7	70%	0.129	0.026	0.006
Landfill Operations (Haul Trucks) (EU ID#: 50)						
Travel of Heavy Equipment In/Around Landfill	7	33.7	70%	0.157	0.031	0.008

Full Bottom Ash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	4	66.5	70%	0.315	0.063	0.015
Empty Bottom Ash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area	1	24	70%	0.111	0.022	0.005
Full Flyash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	2	66.5	70%	0.315	0.063	0.015
Empty Flyash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area	5	24	70%	0.111	0.022	0.005
Full Gyspum Trucks from Gypsum Stack Area to Active Area of Landfill	6	66.5	70%	0.315	0.063	0.015
Empty Gypsum Truck Returning from Active Landfill Site to Gyspum Stack Area	3	24	70%	0.111	0.022	0.005

19.6 Annual Fugitive PM Emissions Per Route Segment

Transport Operation	KyEIS Process ID#	Paved Distance Traveled (VMT/yr)	Unpaved Distance Traveled (VMT/yr)	PM (tpy)	PM10 (tpy)	PM2.5 (tpy)
Bottom Ash Transport						
Full Front End Loader from Bottom Ash Area to Truck	4	752		0.0591	0.0118	0.0029
Empty Front End Loader from Truck to Bottom Ash Area	1	752		0.0484	0.0097	0.0024
Fly Ash Transport						
Full Front End Loader from Fly Ash Area to Truck	2	3,008		0.2366	0.0473	0.0116
Empty Front End Loader from Truck to Fly Ash Area	5	3,008		0.1937	0.0387	0.0095
Gypsum Transport						
Full Front End Loader from Gypsum Stack Area to Truck	6	5,863		0.4612	0.0922	0.0226
Empty Front End Loader from Truck to Gypsum Stack Area	3	5,863		0.3776	0.0755	0.0185
Landfill Operations (Haul Trucks) (EU ID#: 50)						
Travel of Heavy Equipment In/Around Landfill	7	0	365	0.2346	0.0573	0.0057
Full Bottom Ash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	4	0	597	0.5211	0.1274	0.0127
Empty Bottom Ash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area	1	0	597	0.3294	0.0805	0.0081
Full Flyash Trucks from Bottom Ash + Flyash Area to Active Area of Landfill	2	0	2,389	2.0845	0.5097	0.0510
Empty Flyash Truck Returning from Active Landfill Site to Bottom Ash + Flyash Area	5	0	2,389	1.3177	0.3222	0.0322
Full Gyspum Trucks from Gypsum Stack Area to Active Area of Landfill	6	0	5,252	4.5826	1.1204	0.1120
Empty Gypsum Truck Returning from Active Landfill Site to Gyspum Stack Area	3	0	5,252	2.8969	0.7083	0.0708
Total			16,841			

19.7 Consolidated Annual Fugitive PM Emissions Per Category

Emission Unit	PM (tpy)	PM10 (tpy)	PM2.5 (tpy)	Total Material Processed	PM Factor (lb/ 1000ton)	PM10 Factor (lb/ 1000ton)	PM2.5 Factor (lb/ 1000ton)
Bottom Ash Transport	0.11	0.02	0.01	45,120	4.76853	0.95371	0.23409
Fly Ash Transport	0.43	0.09	0.02	180,500	4.76853	0.95371	0.23409
Gypsum Transport	0.84	0.17	0.04	351,800	4.76853	0.95371	0.23409
Landfill Operations (Haul Trucks) (EU ID#: 50)	11.97	2.93	0.29	577,420	41.44884	10.13408	1.01341
Fugitive PM Total	13.34	3.20	0.36				

20. Emergency Tier II 1220 HP Diesel RICE

> Documentation of capacities, emission factors, and emission calculations for emergency RICE engine

20.1 Emission Unit Nomenclature and Capacities

> The emergency was manufactured in 2013 and placed in service in Dec. of 2014.

> The emergency RICE is subject to NSPS Subpart IIII. Pursuant to 60.4211(e), as emergency stationary ICE, the engines can be operated for up to 100 hr/yr for maintenance checks and readiness testing. There is no limit on use of the engines in emergency situations. Emissions represented in the application are based on an assumed 100 hr/yr of operation.

Emission Unit	KyEIS Source ID#	KyEIS Process ID#	Manufact. Date	Startup Date	Engine Rating (hp)	Annual Operating Hours
Emergency Tier II 1220 HP Diesel RICE	51	1	2013	2014	1220	100
Emergency Tier II 1220 HP Diesel RICE	52	1	2013	2014	1220	100

20.2 Source Classification Codes

Emission Unit	KyEIS Source ID#	SCC	SCC Description	SCC Units
Emergency Tier II 1220 HP Diesel RICE	51	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned
Emergency Tier II 1220 HP Diesel RICE	52	20200102	Distillate Oil (Diesel) (2-02-001), Reciprocating (2-02-001-02)	1000 Gallons Distillate Oil (Diesel) Burned

20.3 Diesel Fuel Properties

Diesel fuel heating value:	138,000	Btu/gal	Information from fuel supplier. Expected range is from 132,000 to 138,000 Btu/gal.
Diesel fuel density:	7.05	lb/gal	AP42 Appendix A (1/1995), pg. A-7
Maximum sulfur content:	15	ppm	Information from fuel supplier.

> The SCC for industrial diesel engines is 20200102 with units of 1000 gallons. To convert emission factors in terms of lb/MMBtu to lb/1000 gallons, the approximate fuel heating value listed above is used.

> Sulfur content in the diesel oil used in the engines are based on the October 1, 2010, sulfur limited (60.4207(b)) of 15 ppm.

20.4 Emission Factors Used

20.41 Criteria Pollutant Emission Factors

> AP42 Section 3.4 "Gasoline and Diesel Industrial Engines" (10/1996 edition) provides emission factors for criteria air pollutants, total organic compounds, and HAPs from industrial engines. Factors are expressed in terms of lb/hp-hr and lb/MMBtu. An average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used in AP42 to convert between emission factors based on power output and heat input. This consumption value inherently assumes an engine efficiency of 36.35%. The AP42 criteria pollutant emission factors are listed below:

Brake-Specific Fuel Consumption Value:	7,000	Btu/hp-hr	AP42 Table 3.3-1 (10/1996), Footnote a
Engine efficiency assumption encompassed in this value:	36.35%	= 2,544.48 Btu/hp-hr / 7000 Btu/hp-hr	

AP42 Table 3.4-1 Emission Factors & Vendor EF in Green

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
NOX	0.013	1.858	5.900	256.43
CO	0.00049	0.069	0.220	9.56
SOX	0.000012	0.002	0.005	0.24
PM10	0.00011	0.016	0.050	2.17
TOC (Exhaust + Crankcase)	0.0007050	0.101	0.320	13.90
VOC	0.000287	0.041	0.13	5.65

Sample Calculations (NOX):
1.858 lb/MMBtu = 0.0130073414316894 lb/hp-hr / 7000 Btu/hp-hr * 1E6 Btu/MMBtu
5.9 g/hp-hr = 0.0130073414316894 lb/hp-hr * 453.59 g/lb
256.43 lb/1000gal = 1.858 lb/MMBtu / 1E6 Btu/MMBtu x 138000 Btu/gal x 1000 gal / '1000gal'

> To take into account the lower sulfur content of the diesel fuel burned, for purposes of representing potential SO2 emissions from the engines, the factor in AP42 Table 3.4-1 (Large Stationary Diesel Engines, 10/1996 edition) is used as shown below. This factor expresses SO2 as a function of sulfur content.

AP42 Emission Factor for SO2 based on sulfur content:	1.01 S	lb/MMBtu (where S is the sulfur content in %)
Assumed maximum sulfur content in diesel oil:	15	ppm
Equivalent expressed in terms of percent:	0.0015	%

SO2 Emissions Based on Sulfur Content

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
SO2	0.0000106	0.001515	0.00481	0.2091

Sample Calculation (SO2): 0.001515 lb/MMBtu = 1.01 x 0.0015%

20.42 HAP Emission Factors

> Emission factors provided in AP42 Tables 3.4 (10/1996 edition) are used to estimate emissions of HAPs from the engines. Factors are expressed in terms of lb/MMBtu. As with the criteria pollutants, an average brake-specific fuel consumption value of 7,000 Btu/hp-hr is used to convert between emission factors based on power output and heat input.

AP42 Table 3.4-3 Emission Factors

Pollutant	lb/hp-hr	lb/MMBtu	g/hp-hr	lb/1000gal
Acetaldehyde	5.37E-06	7.67E-04	2.44E-03	0.106
Acrolein	6.48E-07	9.25E-05	2.94E-04	0.013
Benzene	6.53E-06	9.33E-04	2.96E-03	0.129
1,3-Butadiene	2.74E-07	3.91E-05	1.24E-04	0.005
Formaldehyde	8.26E-06	1.18E-03	3.75E-03	0.163
Naphthalene	5.94E-07	8.48E-05	2.69E-04	0.012
Toluene	2.86E-06	4.09E-04	1.30E-03	0.056
Xylenes	2.00E-06	2.85E-04	9.05E-04	0.039

20.5 Emissions For Each Engine

20.51 Summary of Emissions from 1220 HP RICE

Engine Rating:	1220	hp	
Equivalent heat input rate:	8.54	MMBtu/hr	= 1220 hp x 7000 Btu/hp-hr / 1E6 Btu/MMBtu
Equivalent fuel input rate:	0.06188	1000gal/hr	= 8.54 MMBtu/hr x 1E6 Btu/MMBtu / 138000 Btu/gal / 1000 gal/'1000gal'

Pollutant	Emission Factor (lb/1000gal)	Basis	Emissions (lb/hr)	Emissions (tpy)
NOX	256.43	Vendor	15.87	0.79
CO	9.56	Vendor	0.59	0.03
SO2	0.21	15 ppm; AP42 Tbl 3.4-1	0.01294	0.00065
PM10	2.17	Vendor	0.13	0.007
PM2.5	2.17	Equal to PM10	0.13	0.007
VOC	5.65	Vendor	0.35	0.017
CO_2E	22,578	40 CFR 98 Subpart C	1,397.24	69.862
Acetaldehyde	0.106	AP42 Table 3.4-3	6.55E-03	3.28E-04
Acrolein	0.013	AP42 Table 3.4-3	7.90E-04	3.95E-05
Benzene	0.129	AP42 Table 3.4-3	7.97E-03	3.98E-04
1,3-Butadiene	0.005	AP42 Table 3.4-3	3.34E-04	1.67E-05
Formaldehyde	0.163	AP42 Table 3.4-3	1.01E-02	5.04E-04
Naphthalene	0.012	AP42 Table 3.4-3	7.24E-04	3.62E-05
Toluene	0.056	AP42 Table 3.4-3	3.49E-03	1.75E-04
Xylenes	0.039	AP42 Table 3.4-3	2.43E-03	1.22E-04

4. Stack Parameter Summary Table

KyEIS Source ID#	KyEIS Process ID#	Emission Unit Description	Emission Point ID#	Stack Height (ft)	Stack Diameter (ft)	Height of Release (ft)	Stack Flowrate (acfm)	Stack Velocity (ft/sec)	Exit Temperature (F)
01	1	Unit 1 Indirect Heat Exchanger	17	561	26.7	na	2,624,305	78.3	129
02	1	Unit 2 Indirect Heat Exchanger	17	561	26.7	na	2,624,305	78.3	129
03	1	Unit 3 Indirect Heat Exchanger	17	561	26.7	na	2,624,305	78.3	129
07	1	Coal Handling Operations 07 (West Track Hopper)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	2	Coal Handling Operations 07 (Conveyor A-1)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	3	Coal Handling Operations 07 (Conveyor E)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	4	Coal Handling Operations 07 (Conveyor F)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	5	Coal Handling Operations 07 (Conveyor G)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	6	Coal Handling Operations 07 (Conveyor H)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	7	Coal Handling Operations 07 (Conveyor B)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	8	Coal Handling Operations 07 (Conveyor J)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	9	Coal Handling Operations 07 (Coal Stockpile)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
09	1	Coal Handling Operations 09 (East Track Hopper)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	2	Coal Handling Operations 09 (Conveyor A)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	3	Coal Handling Operations 09 (Conveyor B)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	4	Coal Handling Operations 09 (Conveyor C)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	5	Coal Handling Operations 09 (Conveyor J)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
	6	Coal Handling Operations 09 (Coal Stockpile)	Fugitive	Fugitive	Fugitive	16	Fugitive	Fugitive	70
13	1	Coal Handling Operations 13 (Conveyor D)	13	153	2.0	na	9,005	47.8	70
	2	Coal Handling Operations 13 (Conveyor K-1)	14	151	2.0	na	15,997	84.9	70
	3	Coal Handling Operations 13 (Conveyor K)	15	151	2.0	na	16,598	88.1	70
16	1	Coal Crushing (Four Crushers and Crusher House)	16	21	2.0	na	20,000	106.1	70
21	1	Dry Fly Ash Handling	21	106	1.2	na	600	9.35	100
23	1	Combustion Turbine Unit 9 (Fuel: Distillate Oil)	23	175	16.5	na	2,115,600	164.9	851
23	2	Combustion Turbine Unit 9 (Fuel: Natural Gas)	23	175	16.5	na	2,115,600	164.9	851
24	1	Combustion Turbine Unit 10 (Fuel: Distillate Oil)	24	175	16.5	na	2,115,600	164.9	851
	2	Combustion Turbine Unit 10 (Fuel: Natural Gas)	24	175	16.5	na	2,115,600	164.9	851
25	1	Combustion Turbine Unit 8 (Fuel: Distillate Oil)	25	175	16.5	na	2,115,600	164.9	851
	2	Combustion Turbine Unit 8 (Fuel: Natural Gas)	25	175	16.5	na	2,115,600	164.9	851
26	1	Combustion Turbine Unit 11 (Fuel: Distillate Oil)	26	175	16.5	na	2,115,600	164.9	851
	2	Combustion Turbine Unit 11 (Fuel: Natural Gas)	26	175	16.5	na	2,115,600	164.9	851
27	1	Combustion Turbine Unit 6 (Fuel: Distillate Oil)	27	125	17.4	na	2,493,000	174.7	1,090
	2	Combustion Turbine Unit 6 (Fuel: Natural Gas)	27	125	17.4	na	2,493,000	174.7	1,090
28	1	Combustion Turbine Unit 7 (Fuel: Distillate Oil)	28	125	17.4	na	2,493,000	174.7	1,090
	2	Combustion Turbine Unit 7 (Fuel: Natural Gas)	28	125	17.4	na	2,493,000	174.7	1,090
29	1	Combustion Turbine Unit 5 (Fuel: Natural Gas)	29	125	18.0	na	2,127,355	139.3	1,067
30	1	Limestone Truck Dump Station #1	30	50	1.6	na	8,828	74.0	70
31	1	Limestone Truck Dump Station #2	31	50	1.6	na	8,828	74.0	70
32	1	Limestone Stacking Tube	32	70	1.0	na	1,923	41.0	70
33	1	Limestone Reclaim Conveyor #1	33	90	1.0	na	1,923	41.0	70
34	1	Limestone Reclaim Conveyor #2	34	90	1.0	na	1,923	41.0	70
35	1	Road Fugitives from Truck Traffic on Unpaved and Paved Roads	Fugitive	na	na	na	na	na	na
36	1	Unit 1 Cooling Tower with Drift Eliminators	36	na	na	na	na	na	na
37	1	Unit 2 Cooling Tower with Drift Eliminators	37	na	na	na	na	na	na
38	1	Unit 3 Cooling Tower with Drift Eliminators	38	na	na	na	na	na	na
39	1	Dix Dam Crest Gate Emergency Generator	39	6.0	0.17	na	300	Horiz	900
40	1	Dix Dam Station Emergency Generator	40	6.0	0.33	na	1,000	Horiz	900
41	1	CT5 Emergency Generator	41	10.0	0.42	na	2,300	Horiz	900
42	1	CT6 Emergency Generator	42	7.0	0.33	na	1,700	Horiz	900
43	1	CT7 Emergency Generator	43	7.0	0.33	na	1,700	Horiz	900
44	1	CT Area Emergency Fire Pump Engine	44	18.0	0.25	na	1,500	Horiz	900
45	1	Emergency Steam Plant Fire Pump Engine #1	45	14.5	0.50	na	2,782	Horiz	977
46	1	Emergency Steam Plant Fire Pump Engine #2	46	14.5	0.50	na	2,782	Horiz	977
47	1	Emergency Quench Water Pump Engine #1	47	14.5	0.67	na	3,903	Horiz	977
48	1	Emergency Quench Water Pump Engine #2	48	14.5	0.67	na	3,903	Horiz	977
49	1	Emergency Tier II 752 HP Diesel RICE	49	14.5	0.67	na	3,903	Horiz	977
50	6	New Ash/Gypsum Landfill and Haul Trucks	Fugitive	na	na	na	na	na	na
51	1	Emergency Tier II 1220 HP Diesel RICE	51	14.5	0.67	na	5,358	Vert	888
52	1	Emergency Tier II 1220 HP Diesel RICE	52	14.5	0.67	na	5,358	Vert	888

3. Emissions Summary Table

KyEIS Source ID#	KyEIS Process ID#	Emission Unit Description	CO (tpy)	NOX (tpy)	SO2 (tpy)	VOC (tpy)	PM (tpy)	PM10 (tpy)	PM2.5 (tpy)	H2SO4 (tpy)	HCl (tpy)	CO_2e (tpy)
01	1	Unit 1 Indirect Heat Exchanger	125.4	2,759.4	507.1	15.1	519.3	119.4	53.1	236.2	69.2	1,144,061
02	1	Unit 2 Indirect Heat Exchanger	172.5	3,364.0	2,540.9	20.7	476.1	109.5	48.7	324.8	95.1	1,573,538
03	1	Unit 3 Indirect Heat Exchanger	527.6	1,187.1	2,437.9	63.3	696.4	696.4	309.5	478.2	291.0	4,812,320
07	1	Coal Handling Operations 07 (West Track Hopper)					0.14	0.14	0.03			
	2	Coal Handling Operations 07 (Conveyor A-1)					0.11	0.11	0.02			
	3	Coal Handling Operations 07 (Conveyor E)					0.11	0.11	0.02			
	4	Coal Handling Operations 07 (Conveyor F)					0.11	0.11	0.02			
	5	Coal Handling Operations 07 (Conveyor G)					0.11	0.11	0.02			
	6	Coal Handling Operations 07 (Conveyor H)					0.11	0.11	0.02			
09	1	Coal Handling Operations 09 (East Track Hopper)					0.14	0.14	0.03			
	2	Coal Handling Operations 09 (Conveyor A)					0.11	0.11	0.02			
	3	Coal Handling Operations 09 (Conveyor B)					0.22	0.22	0.04			
	4	Coal Handling Operations 09 (Conveyor C)					0.11	0.11	0.02			
	5	Coal Handling Operations 09 (Conveyor J)					0.22	0.22	0.04			
	6	Coal Handling Operations 09 (Coal Stockpile)					3.87	1.85	0.36			
13	1	Coal Handling Operations 13 (Conveyor D)					12.04	12.04	2.41			
	2	Coal Handling Operations 13 (Conveyor K-1)					0.50	0.50	0.10			
	3	Coal Handling Operations 13 (Conveyor K)					0.50	0.50	0.10			
16	1	Coal Crushing (Four Crushers and Crusher House)					1.44	0.72	0.14			
21	1	Dry Fly Ash Handling					1.04	1.04	0.21			
23	1	Combustion Turbine Unit 9 (Fuel: Distillate Oil)	5.7	105.6	87.0	0.7	20.7	20.7	20.7			279,776
23	2	Combustion Turbine Unit 9 (Fuel: Natural Gas)	252.6	238.3	0.5	12.6	39.5	39.5	39.5			701,626
24	1	Combustion Turbine Unit 10 (Fuel: Distillate Oil)	5.7	105.6	87.0	0.7	20.7	20.7	20.7			279,776
	2	Combustion Turbine Unit 10 (Fuel: Natural Gas)	252.6	238.3	0.5	12.6	39.5	39.5	39.5			701,626
25	1	Combustion Turbine Unit 8 (Fuel: Distillate Oil)	5.7	105.6	87.0	0.7	20.7	20.7	20.7			279,776
	2	Combustion Turbine Unit 8 (Fuel: Natural Gas)	252.6	238.3	0.5	12.6	39.5	39.5	39.5			701,626
26	1	Combustion Turbine Unit 11 (Fuel: Distillate Oil)	5.7	105.6	87.0	0.7	20.7	20.7	20.7			279,776
	2	Combustion Turbine Unit 11 (Fuel: Natural Gas)	252.6	238.3	0.5	12.6	39.5	39.5	39.5			701,626
27	1	Combustion Turbine Unit 6 (Fuel: Distillate Oil)	7.0	145.2	490.8	0.9	25.4	25.4	25.4			343,176
	2	Combustion Turbine Unit 6 (Fuel: Natural Gas)	309.8	251.0	0.6	15.4	48.5	48.5	48.5			860,620
28	1	Combustion Turbine Unit 7 (Fuel: Distillate Oil)	7.0	145.2	490.8	0.9	25.4	25.4	25.4			343,176
	2	Combustion Turbine Unit 7 (Fuel: Natural Gas)	309.8	251.0	0.6	15.4	48.5	48.5	48.5			860,620
29	1	Combustion Turbine Unit 5 (Fuel: Natural Gas)	252.6	238.3	0.5	12.6	39.5	39.5	39.5			701,626
30	1	Limestone Truck Dump Station #1					1.46	1.46	1.46			
31	1	Limestone Truck Dump Station #2					1.46	1.46	1.46			
32	1	Limestone Stacking Tube					0.72	0.72	0.72			
33	1	Limestone Reclaim Conveyor #1					0.72	0.72	0.72			
34	1	Limestone Reclaim Conveyor #2					0.72	0.72	0.72			
35	1	Road Fugitives from Truck Traffic on Unpaved and Paved Roads					27.0	5.72	0.74			
36	1	Unit 1 Cooling Tower with Drift Eliminators					1.27	1.27	1.27			
37	1	Unit 2 Cooling Tower with Drift Eliminators					1.66	1.66	1.66			
38	1	Unit 3 Cooling Tower with Drift Eliminators					3.06	3.06	3.06			
39	1	Dix Dam Crest Gate Emergency Generator	0.01	0.02	2.36E-06	0.043	0.001	0.001	0.001			3
40	1	Dix Dam Station Emergency Generator	0.05	0.21	7.16E-05	0.017	0.015	0.015	0.015			8
41	1	CT5 Emergency Generator	0.10	0.48	1.63E-04	0.039	0.034	0.034	0.034			18
42	1	CT6 Emergency Generator	0.08	0.36	1.22E-04	0.029	0.025	0.025	0.025			13
43	1	CT7 Emergency Generator	0.08	0.36	1.22E-04	0.029	0.025	0.025	0.025			13
44	1	CT Area Emergency Fire Pump Engine	0.07	0.32	1.10E-04	0.026	0.023	0.023	0.023			12
45	1	Emergency Steam Plant Fire Pump Engine #1	0.11	0.30	1.99E-04	0.024	0.017	0.017	0.017			21
46	1	Emergency Steam Plant Fire Pump Engine #2	0.11	0.30	1.99E-04	0.024	0.017	0.017	0.017			21
47	1	Emergency Quench Water Pump Engine #1	0.27	0.39	2.57E-04	0.031	0.014	0.014	0.014			28
48	1	Emergency Quench Water Pump Engine #2	0.27	0.39	2.57E-04	0.031	0.014	0.014	0.014			28
49	1	Emergency Tier II 752 HP Diesel RICE	0.29	0.52	0.00	0.02	0.02	0.02	0.02			43
50	6	New Ash/Gypsum Landfill and Haul Trucks					13.34	3.20	0.36			
51	1	Emergency Tier II 1220 HP Diesel RICE	0.03	0.79	0.00	0.02	0.01	0.01	0.01			70
52	1	Emergency Tier II 1220 HP Diesel RICE	0.03	0.79	0.00	0.02	0.01	0.01	0.01			70
TOTAL*			2,709.7	9,009.4	6,815.9	193.2	2,045.7	1,255.2	721.6	1,039.2	455.3	12,759,636

* For the total emissions tallied in this table, only one emission rate for each combustion turbine is counted, corresponding to the maximum between gas or oil. Worse case NG emissions factors are used

APPENDIX E – CAM Plans

CAM Plans for E.W. Brown

1. DRY FLY ASH HANDLING SYSTEM – PM CAM PLAN

This section contains the CAM plan for the Dry Fly Ash Handling System, which utilizes a fabric filter system to control PM emissions from the fly ash silo.

1.1 CAM BACKGROUND

1.1.1 EMISSION UNIT AND PM CONTROLS

Facility:	Kentucky Utilities – Brown Station Burgin, Kentucky Source ID# 21-167-00001
Emission Unit Identification:	KyEIS Source ID# 21; Process ID# 1 **Dry Fly Ash Handling System**
Description:	Fly ash captured in the dry ESPs of each of the three utility boilers (Unit 1, Unit 2 and Unit 3) can be sluiced with bottom ash (via water jet system) to the ash treatment basin on-site or alternatively, the fly ash can be transferred to the fly ash silo. Here, the fly ash is accumulated and is then loaded out into trucks for on-site disposal. The current fly ash silo and bin vent filter system was installed in 1982. The system is rated to receive up to 79.5 ton/hr of fly ash.
PM Controls:	The fly ash silo is 30 ft in diameter and approximately 120 ft tall. Ash delivered to the silo first passes through a primary cyclone separator and the ash is deposited into the silo. The air stream then passes through a bag filter system and then into the ash stream being sluiced to the ash basin. As such this part of the fly ash handling system is not a direct source of emissions. The ash silo is also equipped with a bin vent filter system to capture particulate matter in displacement air released when the silo is being filled. This filter system has a fan rated for 600 cfm that maintains a small draw on the silo. The bin vent filter system exhausts out a 14 inch diameter vent to the atmosphere at a release height of approximately 106 ft. The filter system uses a pulse jet cleaning system.

1.1.2 Applicable Regulations and Current Monitoring for PM

Pollutant:	**PM**
Regulation:	401 KAR 59:010 (New Process Operations)
Emission Limit:	PM is limited to less than $17.31 \times P^{0.16}$ lb/hr where P is tons of material processed per hour and visible emissions less than 20% opacity on a six-minute average basis. (This assumes the process rate is greater than 30 ton/hr.) At the maximum rated capacity, the equivalent mass emission limit is **34.9 lb/hr**.
Current Monitoring Requirements:	59:010 prescribes no specific testing or monitoring requirements that must be followed. The existing Title V permit requires that KU conduct weekly visible emissions observations and to maintain a log of those observations. If any visible emissions are seen, the permit requires that a Method 9 opacity test be conducted and that the control device be inspected to determine the need for repairs. The permit also requires that records be maintained of the daily operating rate, hours of operation, and any maintenance of the baghouse.

1.1.3 Current Estimated Pre-Controlled and Controlled PM Emissions

Pre-Controlled Emissions:	**238.5 lb/hr; 1,045 tpy** No PM emission testing has been performed on the Dry Fly Ash Handling System. In the original 1996 Title V application, an emission factor of 3.0 lb/ton was used to estimate uncontrolled emissions. This factor was derived from a set of emission factors developed by the Midwest Research Institute that were then sanctioned by KDAQ for use by applicable types of sources. The factors developed cover various unit operations associated with coal surface and underground mining, handling of coal, handling of crushed and broken stone, and handling of nonmetallic minerals. The uncontrolled PM emission rate at the design inlet loading capacity (79.5 ton/hr) is 238.5 lb/hr. The previously represented uncontrolled emissions value is being retained for consistency; however, based on the design configuration of the system, this value likely significantly overestimates uncontrolled emission rates.
Controlled Emissions:	**0.24 lb/hr; 1.05 tpy** Controlled emissions rates are based on an estimated 99.9% filter efficiency.

	Potential emissions are less than 0.7% of the allowable rate.
CAM Designation:	Small PSEU

1.2 CAM Applicability

Pursuant to §64.2(a), because the fabric filter system is used to achieve compliance with an emission standard (401 KAR 59:010) and potential uncontrolled PM emissions exceed 100 tpy, CAM applies to the Dry Fly Ash Handling System for PM. Because post-controlled emissions are less than 100 tpy, it is designated as a small PSEU under the CAM regulations, and as such a CAM plan is required to be submitted with the Title V renewal application. This CAM plan addresses the proposed monitoring that will ensure compliance with the PM emission limit.

1.3 Monitoring Approach for PM

To provide on-going assurance of compliance with the applicable PM emission limit, KU proposes to follow the CAM monitoring approach summarized in Table A-1 for the Dry Fly Ash Handling System. The specific details regarding each monitoring method and the monitoring performance criteria for each indicator are then provided in the subsequent sections.

Table A-1. Dry Fly Ash Handling System – Monitoring Approach Summary

Method	Indicator Parameter	Range	Frequency
1. Visual Observations	Visible Emissions	Any visible emissions	Daily
2. System Inspections	Inspection Findings	N/A	Monthly

1.3.1 INDICATOR #1 – VISIBLE EMISSIONS

GENERAL CRITERIA	
Indicator	**Visible Emissions**
Measurement Approach	Personnel will conduct visual observations of the fly ash silo exhaust vent at least once daily, except on days when no fly ash is delivered/loaded, or when weather conditions would prohibit a valid reading.
Indicator Range	An excursion will be defined if visible emissions are perceived.
Corrective Actions	In response to excursions, KU will shut down the system or conduct a Method 9 opacity test to verify compliance with the opacity standard. The opacity readings will be conducted by a certified Method 9 reader. An inspection will then be conducted to determine the cause of the excursion and to correct any revealed performance issues in the most expedient manner possible.
PERFORMANCE CRITERIA	
Data Representativeness	Visual observations will be conducted by trained personnel using EPA Method 22 in a location suitable for assessing the presence of visible emissions at the vent outlet.
Verification of Operational Status	No monitoring hardware is required.
QA/QC Practices and Criteria	Personnel responsible for conducting Method 22 (and if required, Method 9) observations will receive training at least twice per year.
Monitoring Frequency	Visual observations will be conducted at least once daily. Each visual observation will last at least 6 minutes.
Data Collection Procedure	A trained observer will stand at a distance from the exhaust vent sufficient to provide a clear view of any plume against a contrasting background, in a position such that the line of vision is approximately perpendicular to the plume direction. The results of the observation will be recorded in a log.
Averaging Period	N/A
Recordkeeping	• Log of daily visual observations. • Log of maintenance performed on the filter system. • The causes and corrective actions taken associated with any excursions will be noted in the maintenance log. • Training records for personnel conducting visual observations.

Reporting	A summary of visual observations completed and a tally of excursions will be provided in the Title V semiannual monitoring reports.

1.3.2 INDICATOR #2 – FILTER SYSTEM MAINTENANCE INSPECTIONS

GENERAL CRITERIA	
Indicator	**System Inspection Findings**
Measurement Approach	Personnel will conduct a monthly inspection of the filter system and perform routine maintenance in accordance with a written maintenance schedule. Inspections will involve taking the system off-line (while the transfer systems are not in operation), and inspecting the bin vent filter and cleaning systems. No inspections will be performed during months when the system has been continuously idle.
Indicator Range	An excursion is defined if the monthly inspections are not completed or if they reveal the need for non-routine maintenance.
Corrective Actions	Return to prescribed inspection schedule. If performance issues are noted, determine the cause of the excursion and correct them in the most expedient manner possible.
PERFORMANCE CRITERIA	
Data Representativeness	Trained personnel will conduct monthly inspections of the filter system and keep documentation of system checks and maintenance performed.
Verification of Operational Status	No monitoring hardware is associated with this activity.
QA/QC Practices and Criteria	The maintenance inspections will be conducted by trained personnel familiar with the operation of the fly ash handling system.
Monitoring Frequency	Inspections will be completed monthly. Regular component replacements will be made in accordance with the written maintenance schedule.
Data Collection Procedure	Records of system checks and maintenance performed will be recorded in a log.
Averaging Period	N/A
Recordkeeping	• Log of system checks and maintenance performed.
Reporting	N/A

1.4 MONITORING APPROACH JUSTIFICATION

1.4.1 RATIONALE FOR SELECTING PERFORMANCE INDICATORS

Because estimated actual PM emissions from the fly ash silo are less than 0.7% of the allowable (at capacity), there is very little likelihood that the PM or opacity standards will be exceeded except in the case of a complete filter system failure. The indicators selected will help prevent baghouse performance problems from occurring, and will ensure that any baghouse performance problems that do occur are corrected before they could lead to the type of malfunction that would cause an exceedance.

Visible Emissions. When the filter system is operating properly, visible emissions from the exhaust vent will be negligible. The presence of visible emissions indicates reduced performance of the filter system (e.g., loose or torn bags). Therefore, the presence of visible emissions, noted using EPA Method 22 procedures, was selected as a performance indicator because the absence of visible emissions is indicative of operation of the filter system in a manner necessary to comply with the particulate emission standard. Additional monitoring of the filter system itself (e.g., differential pressure) are not warranted given that compliance with the underlying emission limit is easily met in all cases except for major system failures, which would be sufficiently revealed through observations of visible emissions.

Monthly Inspections. Monthly inspections of the filter system was selected as a performance indictor because they will serve to document that the filter system is being maintained in a manner consistent with good air pollution control practices.

1.4.2 RATIONALE FOR SELECTING INDICATOR RANGES

Visible Emissions. Although the presence of visible emissions does not in itself constitute a violation of the PM emission limit or 20% opacity standard, it may indicate that corrective action should be initiated so that any possible exceedance of the particulate standard can be prevented. The excursion threshold of any visible emissions was selected based on operating experience. A visible plume, although not necessarily in excess of the 20% opacity standard, would be present if emissions were in excess of the allowable rate, 34.9 lb/hr. Thus, a more prescriptive or exact method of monitoring emissions (e.g., EPA Method 9) is not necessary.

2. Unit 3 Indirect Heat Exchanger – H_2SO_4 CAM Plan

This section contains the CAM plan for the Unit 3 Boiler for H_2SO_4. The control train for Unit 3 includes an SO_3 mitigation system, which is the primary control system used to minimize the formation and emission of H_2SO_4.

2.1 CAM Background

2.1.1 Emission Unit and H_2SO_4 Controls

Facility:	Kentucky Utilities – Brown Station Burgin, Kentucky Source ID# 21-167-00001
Emission Unit Identification:	KyEIS Source ID# 03 **Unit 3 Indirect Heat Exchanger**
Description:	Unit 3 is a dry bottom, tangentially fired boiler with a heat input capacity of 5,300 MMBtu/hr. At a nominal coal heat input of 11,000 Btu/lb, the boiler can fire up to 240.9 ton/hr of coal. The boiler was constructed in 1971.
H_2SO_4 Controls:	Upon completion of the project proposed through the July 2009 PSD permit application, the boiler will be equipped with low NO_X burners, an SCR system, an SO_3 mitigation system, a dry ESP, and a wet FGD system. The SO_3 mitigation system will be designed specifically to control SO_3 formation and, subsequently, H_2SO_4 emissions.

2.1.2 Applicable Regulations and Current Monitoring for H_2SO_4

Pollutant:	**H_2SO_4**
Regulation:	Expected PSD BACT emission limit to be issued pursuant to 401 KAR 51:017
Emission Limit:	There currently is no H_2SO_4 emission limit in place on Unit 3. The proposed BACT limit is 220 lb/hr, equivalent to 0.042 lb/MMBtu.
Current Monitoring Requirements:	As there is currently no applicable H_2SO_4 emission limit, there are no current monitoring requirements specifically for H_2SO_4.

2.1.3 CURRENT ESTIMATED PRE-CONTROLLED AND CONTROLLED H_2SO_4 EMISSIONS

Pre-Controlled Emissions:	**1,596 lb/hr; 6,990 tpy** The maximum sulfur loading to the Unit 3 Boiler, based on a sulfur content of 3.8%, is 76 lb/ton of coal fired. KU has estimated that up to 3% of the sulfur will convert to SO_3 in the boiler and SCR system. Downstream of the SCR, KU has estimated that SO_3 will decrease by 5% as the flue gas passes through the air heater. Thus, at the exit of the air heater, the equivalent amount of pre-controlled potential H_2SO_4 emissions is estimated to be 6.63 lb/ton [76 lb S/ton * 98.08 lb H_2SO_4/32.07 lb S * 0.03 * (1-0.05)]. At the maximum coal firing rate, this corresponds to an emission rate of 1,596 lb/hr.
Controlled Emissions:	**220 lb/hr; 964 tpy** The SO_3 mitigation system is expect to provide for a 70.96% reduction in SO_3. KU and the control equipment vendors have projected that SO_3 will be partially controlled and reduced in the dry ESP (5%) and wet FGD system (50%) as well. As a result, the potential controlled H_2SO_4 emission rate is 0.914 lb/ton [6.63 lb/ton * (1-0.05) * (1-0.5) * (1-0.7096]. At the maximum coal firing rate, this corresponds to a controlled emission rate of 220 lb/hr.
CAM Designation:	Large PSEU

2.2 CAM APPLICABILITY

The Unit 3 Boiler will became subject to a BACT emission limit for H_2SO_4 upon issuance of the 2010 renewal permit. Pursuant to §64.2(a), because the SO_3 mitigation system is used to achieve compliance with this emission limit and potential pre-controlled H_2SO_4 emissions (calculated at the exit of the air preheater) exceed 100 tpy, CAM applies to the Unit 3 Boiler for H_2SO_4. This CAM plan addresses the monitoring that will ensure compliance with the H_2SO_4 emission limit.

2.3 MONITORING APPROACH FOR H_2SO_4

SO_3 is generated in the Unit 3 Boiler due to the oxidation of sulfur in the combustion process. Additional SO_3 can be generated in the SCR unit due to catalytic oxidation of SO_2 to SO_3. The amount of SO_3 generated is a function of coal sulfur content, operating conditions (e.g., gas temperature) and characteristics of the SCR system (e.g., catalyst material). SO_3 reacts with water in the flue gas to form H_2SO_4 vapor, which then condenses to form sub-micron H_2SO_4 mist. KU will primarily utilize an SO_3 mitigation system to control H_2SO_4 formation and emissions although the SO_3 control attained in the other existing control devices for PM and SO_2, namely the dry ESP (PJFF will replace the ESP in 2016) and wet FGD, is also enhanced due to the SO_3 system.

The SO_3 mitigation system consistent of sorbent receiving and storage systems and an injection system. The sorbent is a dry hydrated lime or trona (sodium sesquicarbonate) and it will be injected in the flue gas immediately downstream of the SCR system and upstream of the dry ESP (or PJFF). The sorbent reacts with the SO_3 to form solid compounds (e.g., sodium sulfate), which are removed in the dry ESP (or PJFF) and wet FGD system.

The effectiveness of the SO_3 mitigation system will be a function of the sorbent injection rate, the stochiometric ratio (e.g., of sodium to sulfur or calcium to sulfur), the sorbent particle size and physical characteristics (e.g., surface area), the degree of mixing in the flue gas, and residence time. Once a particular sorbent and supplier is chosen, the sorbent size and characteristics will be relatively constant. The mixing and residence time properties are not anticipated to be control parameters once the system is installed. Direct continuous measurement of SO_3 and/or H_2SO_4 in the flue gas is not technically feasible currently. Therefore, KU proposes to use the sorbent injection rate as the primary indicator of performance of the SO_3 mitigation system. Continuously monitored SO_2 emissions will also be used as a secondary indicator parameter, since SO_3 formation, and thus H_2SO_4 emissions, can be correlated to SO_2 emissions.

Because Kentucky utilizes a combined construction and Title V permitting program, KU is not in the position of having had a PSD construction permit issued, and initial compliance tests completed, before a Title V permit application with the requisite CAM plan is submitted. Accordingly, certain aspects of the monitoring approach proposed cannot be finalized or implemented until start-up and initial performance testing is completed. Pending future changes based on the results of the initial compliance testing, the monitoring approach outlined in Table A-2 should provide on-going assurance of compliance with the anticipated H_2SO_4 BACT emission limit. The specific details regarding each monitoring method and the monitoring performance criteria are provided following the table.

TABLE A-2. UNIT 3 – MONITORING APPROACH SUMMARY FOR H_2SO_4

Method	Indicator Parameter	Range	Frequency
1. SO_3 Mitigation System Monitoring	Sorbent Injection Rate (lb/hr/acfm)	To be established during initial performance test.	Continuous
2. SO_2 Emissions Monitoring	SO_2 Emission Rate (30-day rolling average)	< 0.09 lb/MMBtu or 87.3% control (90% of allowable)	Continuous

2.3.1 Indicator #1 – Sorbent Injection Rate

General Criteria	
Indicator	**Sorbent Injection Rate (lb/hr/acfm)**
Measurement Approach	Sorbent injection rate will be continuously recorded (data captured at least once every 15 minutes).
Indicator Range	A minimum injection rate threshold will be set during the first performance test. An excursion will be defined if the hourly average injection rate falls below this threshold.
Corrective Actions	In response to an excursion, KU will complete an inspection of the injection system to determine the cause and then will correct any revealed performance issues in the most expedient manner possible.
Performance Criteria	
Data Representativeness	A mass flow meter will be installed on the injection line between the sorbent storage silo and injection point. The specific manufacturer and model for the flow meter will be selected as part of the final engineering design of the system. The mass flow meter will be selected to have an accuracy of approximately ± 10% of the target operating range.
Verification of Operational Status	KU will follow the installation, calibration, and startup procedures recommended by the manufacturer of the equipment prior to putting the metering system into operation.
QA/QC Practices and Criteria	The mass flow meter will be periodically calibrated in accordance with the manufacturer's recommended practices.
Monitoring Frequency	Mass flow data will be captured at least once every 15 minutes when the system is in use.
Data Collection Procedure	The mass flow meter will be equipped with a process logic controller that will capture readings electronically and send them to a data storage drive, where the information can be monitored and trended.
Averaging Period	Up to four readings each hour will be averaged to yield an hourly average injection rate for each operating hour of the day.
Recordkeeping	• Electronic archives of sorbent injection rate data. • The causes and corrective actions taken associated with any excursions will be noted in the maintenance log. • Documentation and records of mass flow meter calibrations.
Reporting	A summary of sorbent injection readings and a tally of excursions will be provided in the Title V semiannual monitoring reports.

2.3.2 Indicator #2 – SO_2 Emission Rates

The Unit 3 Boiler will use a 40 CFR Part 75 compliant CEMS to continuously measure SO_2 at the outlet of the main stack. The data reporting system for the CEMS will calculate SO_2 emission rates in terms of lb/MMBtu based on a 30-day average for the emission unit. SO_2 emissions from Unit 3 are limited to the higher of 0.1 lb/MMBtu or that corresponding to 97% control. 30-day rolling average emission rates greater than 90% of these values will be used as an excursion threshold. In response to an excursion, KU will complete an inspection of the SO_3 mitigation system to determine the cause and then will correct any revealed performance issues in the most expedient manner possible.

2.4 Monitoring Approach Justification

2.4.1 Rationale for Selecting Performance Indicators

Monitoring of the sorbent injection rate provides direct confirmation that the SO_3 mitigation system is in operation. Because other variables associated with the operation of the SO_3 mitigation system (e.g., size and characteristics of the sorbent) are relatively fixed upon start-up and reaching steady-state operation, maintaining the sorbent injection rate at a value that exceeds the lower threshold value established in the performance test will ensure that H_2SO_4 emissions are also kept to levels less than the limit.

During the initial performance test, KU will confirm that when the SO_2 emission rate is below the allowable emission rate, the H_2SO_4 emissions are also below their allowable rate. Because SO_2 and H_2SO_4 emissions should be correlated, SO_2 should serve as a suitable surrogate for H_2SO_4 emissions. Therefore, continuous monitoring of SO_2 at levels below its allowable rate will provide a level of assurance that the H_2SO_4 emissions also remain below the allowable rate.

2.4.2 Rationale for Selecting Indicator Ranges

Because the specific vendor and design for the SO_3 mitigation system has not yet been selected, and initial performance testing has not yet been completed, it is not possible to establish the excursion range for the sorbent injection rate. KU will follow the initial SO_2 and H_2SO_4 compliance testing schedule specified in the amended Title V permit, and anticipates that testing will occur within 180 days of start-up of the SCR system. During the test, monitoring data will be collected to establish the threshold. This testing will be conducted under conditions that would be expected to yield the highest H_2SO_4 emission rate (e.g., highest coal sulfur content and lowest SO_3 sorbent injection rates). SO_2 emissions will be continuously monitored simultaneous with the H_2SO_4 emissions testing. The final test plan will detail the operating conditions and target sorbent injection rates that will be used during which H_2SO_4 emissions are measured. The target sorbent injection rates for the initial test will be determined based on consultations with the equipment vendor.

PPL companies
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232

SENT VIA EMAIL

January 17, 2014

Mrs. Andrea Keatley, Supervisor
Kentucky Division for Air Quality
Frankfort Regional Office
220 Fair Oaks Lane
Frankfort, KY 40601

Re: E.W. Brown Station Title V Permit (V-10-004 R1), Emission Units 1-3, Item 3(f), Indicator levels

Dear Mrs. Keatley:

Upon review of requirements in Kentucky Utilities (KU) E.W. Brown Generating Station's Title V operating permit (V-10-004 R1), it was discovered that control device operating parameters to be used as indicators of sulfuric acid mist (SAM) emissions were not submitted with the initial SAM performance test report as required by permit condition 3(f) for Emission Units 1-3. The test report for the initial SAM testing was submitted to the Kentucky Division for Air Quality on February 25, 2013. Therefore, this letter is being submitted to fulfill permit condition 3(f) for Emission Units 1-3.

As required by permit condition 3(f), operating parameter data was collected during the testing to establish indication of SAM emission levels. The operating parameters that were monitored were: 1) operating load (in megawatts, MW), 2) sorbent injection rate (in pounds per hour, lb/hr) and 3) wet flue gas desulfurization (WFGD) inlet sulfur dioxide (SO_2) concentration (in pounds per million British thermal units, lb/mmBtu). From the test results and operating parameter data collected, the attached matrix was developed to establish proper sorbent injection rates for maintaining SAM emission rates at appropriate levels at varying unit load and WFGD inlet SO_2 concentrations. Sorbent injection levels at or above the levels seen in this matrix while also taking into consideration the ±10% accuracy of the sorbent injection metering system mentioned in permit condition 4(n) are an indication of appropriate SAM emission control levels. Since the end of the initial SAM test conducted on January 22, 2013, the station has been compliant with this matrix. The matrix has also been integrated into the control systems of the station's SAM mitigation system.

Thank you for your review of this information. If you have any questions or need further information, please contact me at (502) 627-4043 or jason.wilkerson@lge-ku.com.

Respectfully,
Jason Wilkerson

Jason Wilkerson
Environmental Affairs
LG&E and KU Energy

Attachment

CC: Jarrod Bell, Supervisor, KDAQ Frankfort Regional Office

E.W. Brown Unit 3 LOAD (MW)	FGD SO2 Inlet Indication (lb/mmBtu)					
	6.2 to 6.1	6.0 to 5.9	5.8 to 5.7	5.6 to 5.3	5.2 to 4.9	4.8 to 0
180	680	650	630	610	570	520
190	720	690	670	640	600	550
200	760	730	710	680	630	580
210	800	760	740	710	660	610
220	830	800	780	750	690	640
230	870	840	810	780	720	670
240	910	870	850	810	760	700
250	950	910	880	850	790	730
260	990	950	920	880	820	760
270	1030	980	950	920	850	780
280	1060	1020	990	950	880	810
290	1100	1060	1020	980	910	840
300	1140	1090	1060	1020	950	870
310	1180	1130	1100	1050	980	900
320	1220	1170	1130	1090	1010	930
330	1250	1200	1170	1120	1040	960
340	1290	1240	1200	1160	1070	990
350	1330	1270	1240	1190	1100	1020
360	1370	1310	1270	1220	1140	1050
370	1410	1350	1310	1260	1170	1080
380	1450	1380	1340	1290	1200	1110
390	1480	1420	1380	1330	1230	1140
400	1520	1460	1420	1360	1260	1170
410	1560	1490	1450	1390	1290	1190
420	1600	1530	1490	1430	1330	1220
430	1640	1570	1520	1460	1360	1250
440	1670	1600	1560	1500	1390	1280
450	1710	1640	1590	1530	1420	1310
460	1750	1680	1630	1570	1450	1340

220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232

SENT VIA EMAIL

March 19, 2014

Mr. James Morse
Kentucky Division for Air Quality
200 Fair Oaks Lane
Frankfort, KY 40601

Re: **Kentucky Utilities/E.W. Brown Generating Station**
Use of Temporary SO_3 Sorbent Material Injection System

Dear Mr. Morse:

Kentucky Utilities (KU) has determined that the E.W. Brown Unit 3 SO_3 mitigation system's sorbent material storage silos will need to be relocated in preparation of the future installation of the E.W. Brown Unit 3 pulse jet fabric filter (PJFF) . The SO_3 mitigation system's Sorbent Storage Silos are listed as item 20 on the Insignificant Activities list found in Section C of the station's Title V operating permit (V-10-004 R1). KU plans to move the storage silos during the upcoming E.W. Brown Unit 3 maintenance outage currently scheduled to begin on March 29, 2014. The silos will be moved from their current location, west of the Unit 3 Induced Draft (ID) Fans, to the east side of the duct exiting the Unit 3 ID Fans. The outage is currently scheduled to end on April 25, 2014.

KU is submitting notification that temporary sorbent material injection systems will be installed near the current location of the permanent storage silos to support continued operation of the E.W. Brown Unit 3 SO_3 mitigation system while the permanent storage silos are moved. The temporary sorbent material injection systems (including silos and blowers) will be utilized to store sorbent material and achieve the appropriate sorbent material injection rates to maintain compliance with the station's emission limit. The temporary injection systems will only be used while the permanent system is not operational. Therefore, KU does not anticipate any increase in emissions from this activity. The temporary injection systems will be removed once the permanent injection system returns to full operation following the maintenance outage.

If you have any questions regarding this information, please contact me at 502-627-4043 or jason.wilkerson@lge-ku.com.

Respectfully,

Jason Wilkerson

Jason Wilkerson
Environmental Affairs

CC: Ben Markin, KDAQ Permit Review Branch
Jarrod Bell, KDAQ Frankfort Regional Office

SULFURIC ACID MIST EMISSIONS TEST REPORT

E.W. BROWN GENERATING STATION
Boilers 1, 2 and 3 – CS123 Stack
815 Dix Dam Road
Harrodsburg, Kentucky

October 16, 2014

PPL companies

Submission of Control Device Operating Parameters

Per permit condition 3(f) of E.W. Brown's Title V operating permit (V-10-004 R2, see page 8 of 76), control device operating parameters that will be used as an indicator of SAM emissions are to be established during the initial SAM performance testing conducted on E.W. Brown Units 1 through 3. The initial SAM performance testing was completed on February 25, 2013. Based on that test, control device operating parameters were submitted on January 17, 2014.

However, during the SAM performance testing detailed in this report, the SAM control device for E.W. Brown began using a new dry sorbent injection material. Therefore, the previously submitted control device parameters needed to be adjusted. Based on the operating data gathered during this SAM performance test (as provided in Appendix B), the new control device parameters for the E.W. Brown SAM control device are seen below in Table 2.

TABLE 2: SAM Control Device Operating Parameters

	FGD SO2 Inlet Indication (lb/mmBtu)								
LOAD (MW)	6.2 to 6.1	6.0 to 5.9	5.8 to 5.7	5.6 to 5.3	5.2 to 4.9	4.8 to 4.5	4.4 to 4.1	4.0 to 3.1	3.0 to 0
180	420	410	390	380	350	320	300	270	200
190	440	430	410	400	370	340	310	280	210
200	470	450	440	420	390	360	330	300	220
210	490	470	460	440	410	380	350	310	230
220	510	500	480	460	430	400	360	330	250
230	540	520	500	480	450	410	380	340	260
240	560	540	520	510	470	430	400	360	270
250	580	560	550	530	490	450	410	370	280
260	610	590	570	550	510	470	430	390	290
270	630	610	590	570	530	490	450	410	300
280	650	630	610	590	550	510	460	420	310
290	680	660	630	610	570	520	480	440	330
300	700	680	660	630	590	540	500	450	340
310	720	700	680	650	610	560	510	470	350
320	750	720	700	680	630	580	530	480	360
330	770	750	720	700	650	600	550	500	370
340	800	770	740	720	670	610	560	510	380
350	820	790	770	740	690	630	580	530	390
360	840	820	790	760	710	650	600	540	410
370	870	840	810	780	730	670	610	560	420
380	890	860	830	800	750	690	630	570	430
390	910	880	850	820	770	710	650	590	440
400	940	910	880	850	780	720	660	600	450
410	960	930	900	870	800	740	680	620	460
420	980	950	920	890	820	760	700	630	470
430	1010	970	940	910	840	780	710	650	480
440	1030	1000	960	930	860	800	730	660	500
450	1050	1020	990	950	880	820	750	680	510
460	1080	1040	1010	970	900	830	760	690	520

The plant operating data is shown in Appendix B. Coal analysis results are shown in Appendix C.

APPENDIX F – Acid Rain

Steve Noland
Manager, Environmental Air Section
LG&E Co. and Kentucky Utilities Co.
LG&E Building
220 West Main Street
Louisville, KY 40202
T (502) 627-2940

October 20, 2014

Mr. Sean Alteri, Director
Division for Air Quality
200 Fair Oaks Lane
Frankfort, KY 40601

Dear Mr. Alteri;

This transmits revised Phase II NOx Compliance Plans for Kentucky Utilities Company's coal-fired units at E W Brown, Ghent, and Green River.

The only difference from existing Plans already in effect is that they are being submitted on U.S. EPA's new forms. EPA's new forms have eliminated an expiration date to enable the effective dates of the Acid Rain Permit section of Title V Permits to match with the Title V Permits themselves.

Part 76 (Acid Rain Nitrogen Oxides Emission Reduction Program) applies to existing coal-fired units (defined as commenced commercial operation prior to November 15, 1990). Therefore, it does not apply to the combustion turbines at E W Brown.

The Averaging Plan is based on meeting Phase II emission limits. Under Part 76, a unit will be in compliance if it meets its emission limit. However, units will be also be determined to be in compliance if their combined Btu-weighted average NOx emission rate is below what it would be if each unit met its Phase II limit.

If you have any questions, please contact me at 502-627-2940 or Glenn Gibian at 859-367-5658.

Sincerely,

Steve Noland

Steve Noland (DR #604651)

Cc: U.S. EPA, Clean Air Markets Division

United States
Environmental Protection Agency
Acid Rain Program

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

Acid Rain NO_X Averaging Plan

For more information, see instructions and refer to 40 CFR 76.11 Page 1

This submission is: ☐ New ☒ Revised Page 1 of 2

STEP 1

Identify the units participating in this averaging plan by plant name, State, and unit ID. In column (a), fill in each unit's applicable emission limitation from 40 CFR 76.5, 76.6, or 76.7. In column (b), assign an alternative contemporaneous annual emissions limitation (ACEL) in lb/mmBtu to each unit. In column (c), assign an annual heat input limitation in mmBtu to each unit. Continue to page 3 if necessary.

Plant Name	State	Unit ID#	(a) Emission Limitation	(b) ACEL	(c) Annual Heat Input Limit
E W BROWN	KY	1	0.50	0.50	4,597
E W BROWN	KY	2	0.45	0.45	11,592
E W BROWN	KY	3	0.45	0.45	28,309
GHENT	KY	1	0.45	0.45	37,993
GHENT	KY	2	0.40	0.40	29,838
GHENT	KY	3	0.46	0.46	27,081
GHENT	KY	4	0.46	0.46	28,897
GREEN RIVER	KY	4	0.46	0.46	3,703
GREEN RIVER	KY	5	0.50	0.50	9,038

STEP 2

Use the formula to enter the Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan and the Btu-weighted annual average emission rate for the same units if they are operated in compliance with 40 CFR 76.5, 76.6, or 76.7. The former must be less than or equal to the latter.

Btu-weighted annual emission rate averaged over the units if they are operated in accordance with the proposed averaging plan		Btu-weighted annual average emission rate for same units operated in compliance with 40 CFR 76.5, 76.6 or 76.7
0.45	≤	0.45

$$\frac{\sum_{i=1}^{n} (R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n} [R_{Ii} \times HI_i]}{\sum_{i=1}^{n} HI_i}$$

Where,

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, in lb/mmBtu, as specified in column (b) of Step 1:

R_{Ii} = Applicable emission limitation for unit i, in lb/mmBtu, as specified in column (a) of Step 1;

HI_i = Annual heat input for unit i, in mmBtu, as specified in column (c) of Step 1;

n = Number of units in the averaging plan

Plant Name (from Step 1)
E W BROWN, GHENT, GREEN RIVER

STEP 3

Identify the first calendar year in which this plan will apply.

January 1, _2015________________________

STEP 4

Read the special provisions and certification, enter the name of the designated representative, and sign and date.

Special Provisions

Emission Limitations

Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_X under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan, and
(a) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan,
(b) For each unit with an alternative contemporaneous emission limitation more stringent than the applicable emission limitation in 40 CFR 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan, or
(ii) If one or more of the units does not meet the requirements of (i), the designated representative shall demonstrate, in accordance with 40 CFR 76.11(d)(1)(ii)(A) and (B), that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in 40 CFR 76.5, 76.6, or 76.7.
(iii) If there is a successful group showing of compliance under 40 CFR 76.11(d)(1)(ii)(A) and (B) for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under (i).

Liability

The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

Termination

The designated representative may submit a notification to terminate an approved averaging plan, in accordance with 40 CFR 72.40(d), no later than October 1 of the calendar year for which the plan is to be terminated.

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 Noland, DR #604651	
Signature Steve Noland	Date 10/20/2014

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 Acid Rain permit renewal

STEP 1

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

Facility (Source) Name **E W BROWN**	State **KY**	Plant Code **1355**

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)
1	Yes
2	Yes
3	Yes
5	Yes
6	Yes
7	Yes
8	Yes
9	Yes
10	Yes
11	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 T. Noland (Designated Representative)	
Signature	Date

Instructions for the Acid Rain Program Permit Application

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, contact EIA at (202) 586-4325 or (202) 586-2402.

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 G – CT HOURS

CLARIFICATION THAT THE 2,500 HOUR OPERATIONAL LIMIT ON THE E.W. BROWN COMBUSTION TURBINE UNITS APPLIES ONLY TO TIME OF COMBUSTION OF #2 FUEL OIL

Overview

At the time of original permitting of the E.W. Brown combustion turbines (CTs), natural gas was not available at the plant site and the forecasted need of the units did not conflict with the 2,500 hour limitation. With the original construction permit application submitted to the Kentucky Division for Air Quality (KyDAQ) by Kentucky Utilities (KU), the use of natural gas as a combustion fuel was addressed in the Technical Support Document that accompanied the application; however, the use of natural gas was not addressed in the primary application documents. The KyDAQ received the application on June 14, 1991 and issued a "Preliminary Determination of Approval" for public comment on September 11, 1991 with #2 fuel oil as the only fuel option (Attachment A). The draft permit contained a limit of 2,500 hours per year, consistent with the BACT determination for fuel oil. During the comment period, KU requested that natural gas be added as a fuel and provided KyDAQ with the DEP forms reflecting natural gas as a fuel option (Attachment B). The forms provided in response by KU utilized natural gas combustion emission factors provided by each vendor being considered at 2,500 hours per year as had been previously in modeled for the PSD emission limitations while combusting fuel oil. The forms should have more correctly shown maximum potential emissions from combustion of natural gas limited only to the PSD emission limits previously developed from worst case conditions (fuel oil) at the vendor provided NG emission factors. The 2500 hours of operation utilized in the previous calculations are only an artifact of the emission factors noted in the current permit. The current Title V operating permit states that the permittee shall use the result of the most recent performance test to demonstrate compliance.

The "Final Determination to Construct" was issued by KyDAQ on March 10, 1992 (Attachment C). In response to comments from KU that were included with the final determination, KyDAQ stated "…it was determined that the turbines could be conditioned to fire both natural gas and/or #2 fuel oil. Also, the Best Available control Technology (BACT) will remain as determined in the preliminary determination since the worst case emissions are generated from the #2 fuel oil." The 2,500 hour restriction on hours of operation had no basis other than BACT for SO2 with combustion of fuel oil. It was not needed to address air quality impact issues, PSD/BACT determination, or any other technical or environmental reason when combusting natural gas.

Although KU did not expect to operate the CTs more than 2,500 hours/year at the time, it now can be viewed as a material mistake. Changing fuel prices and additional regulations for control of mercury emissions and greenhouse gases indicates an increased need of generation provided by combustion of natural gas.

Subsequent to the original permit, natural gas supply has been obtained at the E.W. Brown Station. Although #2 fuel oil is still utilized for a portion of operation of the CT units, the majority of operation is currently from utilization of natural gas.

BACT information from initial permit application

From review of the original permitting documentation, the 2,500 hour limitation was based solely on the BACT determination for fuel oil, and specifically for SO2. The construction of the CT units was subject to a BACT review for PM/PM10, Be, SO2, NOx, CO, and VOC. BACT determinations were separately made for both fuel oil and natural gas as included in Table 2-3 (Attachment D) from the Technical Support Document (TSD) that accompanied the original permit application. The BACT determinations for fuel oil included an "hourly limit of 2,500 hours/year and 0.3% sulfur fuel" for SO2, "water injection" for NOx, and "Good Combustion Practices" for all other pollutants. The BACT determinations for natural gas were "water injection" for NOx and "good combustion control" for all other pollutants. There was no BACT limitation on hours of operation with natural gas.

Clarification that the 2500 hour limitation applies only to #2 fuel oil

With consideration that BACT was determined based on combustion of fuel oil at 2,500 hours per year, KU is not seeking to remove that permit requirement. Our request, however, is that the language of the Title V permit clearly applies the 2,500 hour limitation specifically to operation when combusting #2 fuel oil.

Unit Specific Emission Limitations

At the time of submittal of the application, the specific CT vendor had not been selected. The potential emissions contained in the application were determined from "worst case" information utilizing #2 fuel oil as provided by the vendors at maximum load for 2,500 hours per year. The potential emissions that triggered PSD (as indicated above) were translated into unit specific BACT emission limitations utilizing worst case (fuel oil) factors at 2,500 hours per year. Those limitations were subsequently included in the E.W. Brown Station Title V permit.

The requested clarification would limit natural gas operation only to compliance with existing emission limits

KU is not requesting a change to any existing Title V emissions limitations (e.g. hourly or annual emission limits) that apply during operation of these CT units including combustion from natural gas as well as fuel oil. However, KU is requesting permit language clarification that constrains combustion with natural gas to only compliance with the existing emission limits as determined by applicable monitoring and reporting of total emissions from each unit.

Specifically, consistent with the PSD BACT determinations submitted during the initial permitting process, KU is requesting the permit language clearly identify the 2,500 hours per year operation limitation to apply only during the combustion of fuel oil.

Suggested Permit Language

1. Operating Limitations: (b) The maximum operating hours for each unit shall not exceed 2,500 hours per year ***when combusting fuel oil*** based on a twelve-month rolling total [401 KAR 51:017].

In Summary

The environmental regulatory landscape is driving a need for increased generation of electricity by cleaner fuels such as natural gas. As written, the permit unnecessarily restricts the gas operation of the CT units to 2,500 hours per year without a regulatory basis. This clarification will not increase emissions above the original and currently permitted levels and does not conflict with regulations that prevent deterioration of the air quality, but allows for operation while combusting natural gas to focus solely on complying with applicable emission limitations. In addition, it will remove an unnecessary obstacle to providing low-cost electricity, and will enhance KU's and Kentucky's ability to meet proposed carbon reduction requirements.

In support of this requested clarification, KU is including the following attachments:

A. Preliminary Determination to Construct issued by KyDAQ
B. KU response and forms provided to KYDAQ's in support of combusting with natural gas as a result of comments filed by KU
C. Final Determination to Construct issued by KyDAQ
D. TSD Table 2-3 "BACT Results"
E. Entire TSD

Units 23-29 Beryllium and NG

Beryllium (Be) is recognized as an element associated with combustion of fuel oil and is included with emission limitations, testing, and reporting requirements in the E.W. Brown permit for the Combustion Turbines (CTs) sources. However, KU contends that Be is not an element associated with combustion of natural gas in CTs and that the firing of natural gas should not include limitations or requirement for testing and reporting Be emissions.

Although associated with combustion of fuel oil, EPA does not identify or include Be as an emission component associated with the use of natural gas as a fuel for combustion turbines (see attached "Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines). In addition, to date, emissions testing at the Brown CTs while combusting natural gas has not yielded evidence of emissions of beryllium. In order to fulfill the current permit requirements to provide emissions data during testing of the Brown CTs while operation with natural gas, the analytical detection limit of the instrumentation utilized in analyzing Be concentrations in stack samples (0.001 ppm) has been reported as emissions for all tests.

Consistent with Appendix G of this renewal application, emission data was developed based on firing fuel oil at maximum usage for 2,500 hours per year. The current permit states that "the permittee shall be considered in compliance with the beryllium limit while burning natural gas. Hence, KU is requesting the addition of this verbiage to clarify that the limit does not apply while burning NG. KU is requesting that the renewal permit, under the beryllium emission limits, add "**while burning fuel oil.**" "Beryllium emissions from each unit shall not exceed the following limits ***while burning fuel oil.***"

AP-42 table 3.4-1, Emission factors for Natural Gas-Fired Gas Turbines, does not have a beryllium emission factor for NG turbines. EPA's emission factor documentation for AP-42 Section 3.1 Stationary Gas Turbines, states that "for cases where the concentration of a specific pollutant was below the test method detection limit and a detection limit was provided, then half of the detection limit was used to calculate an emission factor. **If no detection limit was provided, then the results from that test were not used."**

The current permit under 2h/page 32, states that "as an alternative to conducting beryllium stack testing the permitted may use fuel supplier certification or fuel sampling for each fuel supplier certification or fuel sampling **for each fuel**, consistent with the fuel monitoring plan in Subsection 4(e). **KU is requesting the removal of "for each fuel" from 2(h) and replacing it with "fuel oil."**

Additionally, it is KU's contention that the use of pipeline quality NG should preclude the need to perform annual analysis on the NG and/or test for beryllium when stack tests are performed. Under 3(b), testing, KU requests that the first sentence be revised to clarify that beryllium testing is not required for NG. **"To demonstrate compliance with the limits required by 401 KAR 51:017, the permittee shall conduct performance tests for carbon monoxide, particulate matter, VOC and beryllium for each unit. Beryllium performance tests only needs to be conducted for fuel oil; pipeline quality NG is being used."**

The specific monitoring requirements under 4(e) reads as follows: "The permittee shall continue to use the custom fuel monitoring plan, previously approved and provided in 40 CFR 75, Appendix D, Tables D4-D5 and Sections 2.2.1,2.23,2.2.4.2, and 2.2.4.3. The permittee shall maintain a copy onsite of the chosen monitoring plans for natural gas and oil." **KU is requesting the removal of "natural gas" from 4(e) and adding "fuel" before "oil."** Beryllium is not present in NG.

The CT beryllium stacks tests have been performed on fuel oil and NG. The NG lb/hr Beryllium emission rates were based on the detection limit of 0.001 mg/l (ppm); because beryllium was not detected in the NG on any of the tested CTs and the maximum natural gas volumetric flow rate during the testing. The beryllium NG lb/hr emission rates are all around 100 times less than the permit limits. If we had used half of the detection limit, as EPA does for the Beryllium fuel oil emission factor, our beryllium NG lb/hrs emission rates would have been even small (see the Ventura County Air Pollution Control District, California Emission Factor Document).

To summarize, KU is requesting the following:

- 2(h), first sentence - Add "**while burning fuel oil**." "Beryllium emissions from each unit shall not exceed the following limits ***while burning fuel oil***."
- 2(h), compliance demonstration/first paragraph – Delete verbiage after the first sentence. Performance tests have been performed.
- 2(h), compliance demonstration/second paragraph - Remove "**for each fuel**" and replace it with "**fuel oil.**"
- 3(b), first sentence –Revise first sentence "To demonstrate compliance with the limits required by 401 KAR 51:017, the permittee shall conduct performance tests for carbon monoxide, particulate matter, VOC and beryllium for each unit. **Beryllium performance tests only needs to be conducted for fuel oil; pipeline quality NG is being used.**"
- 4(e), last sentence - Remove "**natural gas**" and add "**fuel**" before "**oil.**"

Attachments (End of Appendix G)
Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines (April 2000)
AP-42, Table 3.1-3 – Emission Factors for Metallic HAPs from Distillate Oil-Fired Stationary Gas Turbines
AP-42, Table 3.1-5 – Emission Factors for Metallic HAPs from Natural Gas-Fired Stationary Gas Turbines
Ventura County Air Pollution Control District, California Emission Factor Document
Selected pages from E.W. Brown Title V Permit/V-1—004 R2

ATTACHMENT A

Preliminary Determination to Construct issued by KyDAQ

Carl H. Bradley
SECRETARY

Wallace G. Wilkinson
GOVERNOR

COMMONWEALTH OF KENTUCKY
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION CABINET
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
DIVISION FOR AIR QUALITY
316 St. Clair Mall
Frankfort, Kentucky 40601

September 11, 1991

Ms. Caryl M. Pfeiffer, Manager
Environmental Services
Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

RE: E.W. Brown Generating Station
I.D. #102-2740-0001
Log #B415

Dear Ms. Pfeiffer:

Enclosed is a copy of the preconstruction review performed by this Division for the proposed turbines to be constructed at the E.W. Brown Station. The public notice on the availability of this document for comments by persons affected by the proposed construction was mailed to the newspaper on the above date and the comment period will expire thirty (30) days from the date of publication.

If you have any questions, please contact this office at (502) 564-3382.

Sincerely,

James W. Dills, Manager
Permit Review Branch

JWD/ALW/awj

Enclosure

cc: Bluegrass Regional Office

PRECONSTRUCTION REVIEW AND PRELIMINARY DETERMINATION

ON THE APPLICATION OF

KENTUCKY UTILITIES COMPANY

E.W. Brown Generating Station

To Construct

Eight simple cycle combustion turbines at their existing generating station located on Curdsville Road in Mercer County, Kentucky

Review and Analysis By:

Andrea L. Wilson

EIS NUMBER:	102-2740-0001	SIC CODE:	4911
REGION:	Bluegrass	COUNTY:	Mercer
LOG NUMBER:	B415	DATE COMPLETE:	July 12, 1991
UTM COORDINATES:	700.6E, 4184.8N Zone 16	TYPE OF REVIEW:	PSD, NSPS, and NSR

DIVISION FOR AIR QUALITY
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION CABINET
316 ST. CLAIR MALL
FRANKFORT, KENTUCKY 40601

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Kentucky Utilities Company proposes to install a maximum of eight simple cycle combustion turbines at their E. W. Brown Generating Station located in Mercer County, Kentucky. This project is considered a major modification of an existing major source since there are significant net emission increases for sulfur dioxide (SO_2), nitrogen oxides (NOx), total suspended particulate (PM/PM_{10}), carbon monoxide (CO), beryllium (Be) and volatile organic compounds (VOC). Therefore, the proposed construction is subject to a Prevention of Significant Deterioration (PSD) review for each of these pollutants. In addition, the turbines are subject to the New Source Performance Standards (NSPS) for NOx and SO_2 since the heat input is greater than 10.0 mmBTU/hour.

For each pollutant subject to the PSD Regulation 401 KAR 51:017, a review of the following is required:

1. A demonstration of the Best Available Control Technology (BACT);

2. An Air Quality Impact of the proposed construction on the National Ambient Air Quality Standards (NAAQS) and the applicable PSD increments;

3. Impact on Class I Areas;

4. Effects of the proposed construction on Soils, Vegetation, and Visibility;

5. Air Quality Impact projected for the area due to generalized commercial, residential, and industrial growth, and other types of growth as a result of the proposed construction;

6. Preparation of a preliminary review document available for public inspection, comments, and public hearing if requested.

Since the review demonstrates that all applicable PSD, NSPS, and NSR requirements will be met, a preliminary determination has been made that the construction permit should be issued as conditioned, but contingent to the satisfactory resolution of any adverse public comments which might be received.

I. BACKGROUND

A construction permit application was received from Kentucky Utilities Company on June 14, 1991, and was considered complete by the Kentucky Division for Air Quality on July 12, 1991. This application is for the construction of up to eight, #2 fuel oil fired, simple cycle combustion turbines at the E.W. Brown Generating Station. Each of these units will have a nominal rated capacity between 75 and 100 megawatts and will be used to meet the system peak load requirements. Kentucky Utilities is currently evaluating three turbine vendors. However, at the time of their PSD submittal, they had not committed to a specific vendor. Therefore, information relating to each vendor was evaluated and compared to obtain a worst-case scenario for the PSD review. Each turbine will have the capability of combusting natural gas or #2 fuel oil. However, since natural gas is not currently available, the review is based on the usage of #2 fuel oil only.

II. INFORMATION GIVEN AND ASSUMED

All the information used in the determination of this review was derived from the application and assumptions listed therein.

III. EMISSION ANALYSIS

The calculated potential emission increases from the proposed project are summarized in Table III.1. Since the potential emissions of particulate, sulfur dioxide, carbon monoxide, nitrogen oxide, and beryllium will exceed their respective significant emission rates, a PSD review is required for each of these pollutants.

TABLE III.1 SUMMARY OF EMISSIONS

Pollutant	Proposed Potential Emissions (Tons/yr)	PSD Significant Emission Rates (Tons/yr)
Particulate (PM_{10})	668	25 (15)
Sulfur Dioxide	4200	40
Carbon Monoxide	750	100
Nitrogen Oxide	2485	40
VOC	204	40
Lead	0.120	0.6
Beryllium	0.0337	0.0004
Mercury	0.0405	0.1

III. EMISSION ANALYSIS (CONTINUED)

Since the applicant has not committed to a vendor for the turbines, reviews of the three possible vendors were evaluated. The potential emissions of PM/PM_{10}, NOx, CO, and VOC were obtained from the application and are based on guaranteed information provided from each vendor of the turbines. For this application, the emissions of PM_{10} were assumed to be identical to those of the total suspended particulate. Additionally, emissions were calculated using a limited annual operation of 2,500 hours per year. The SO_2 emissions were calculated by a material balance based on the maximum sulfur content 0.3% of the fuel. Emissions from each vendor were compared to determine the maximum potential emission of each pollutant. The following calculations represent the worst-case scenario from this vendor comparison:

Given Vendor Information:

VENDOR 1 (General Electric):
Proposed amount of turbines to install: 7
Annual Fuel Consumption: 19,132,000 gallons, each
Heating Value: 18,550 BTU/lb
Heating Capacity: 1020 mmBTU/Hour, each

VENDOR 2 (Westinghouse):
Proposed amount of turbines to install: 8
Annual Fuel Consumption: 25,694,500 gallons, each
Heating Value: 18,250 BTU/lb
Heating Capacity: 1349 mmBTU/Hour, each

VENDOR 3 (ABB):
Proposed amount of turbines to install: 7
Annual Fuel Consumption: 20,173,700 gallons, each
Heating Value: 18,143 BTU/lb
Heating Capacity: 1053 mmBTU/hour, each

Calculations of Potential Emissions:

NOTE** Maximum PM/PM_{10}, SO_2, CO, and VOC emissions were achieved using the information provided from Vendor 2 (Westinghouse). Maximum NOx emissions were obtained from Vendor 3 (ABB). Mercury, lead, and beryllium emissions were calculated using emission factors for oil combustion from Toxic Air Pollutant Emission Factors - A Compilation For Toxic Compounds and Sources (EPA-450/2-88-006a).

TOTAL EMISSIONS:

PM/PM_{10}: 536 lb/hr
(536 lb/hr)*(2500 hr/yr)/(2000 lb/ton) = 670 tons/yr

CO:	600 lb/hr
	(600 lb/hr)*(2500 hr/yr)/(2000 lb/ton)= 750 tons/yr
NOx:	1988 lb/hr
	(1988 lb/hr)*(2500 hr/yr)/(2000 lb/ton)=2485 tons/yr
VOC:	163 lb/hr
	(163 lb/hr)*(2500 hr/yr)/(2000 lb/ton)= 204 tons/yr
SO_2:	74,000 lb/hr * 0.3% sulfur * 2 lb SO2/lb Sulfur=
	444 lb/hr * 8 turbines= 3552 lb/hr
	(3552 lb/hr)*(2500 hr/yr)/(2000 lb/ton)= 4440 tons/yr
Mercury:	(3.0 lb/1*10^{12} BTU) * (1349 mmBTU/hr) * 8 turbines= 0.0324
	(0.0324 lb/hr)*(2500 hr/yr)/(2000 lb/ton)= 0.0405 ton/yr
Beryllium:	(2.5 lb/1*10^{12} BTU) * (1349 mmBTU/hr) * 8 turbines= 0.0270 lb/hr
	(0.0270 lb/hr)*(2500 hr/yr)/(2000 lb/ton)= 0.0337 ton/yr
Lead:	(8.9 lb/1*10^{12} BTU)*(1349 mmBTU/hr) * 8 turbines= 0.0960 lb/hr
	(0.0960 lb/hr)*(2500 hr/yr)/(2000 lb/ton)= 0.120 ton/yr

IV. AIR QUALITY ANALYSIS

An air quality analysis must be performed for each pollutant subject to PSD to insure that the emissions generated from the project will not violate the applicable NAAQS or PSD increment. This analysis was demonstrated using the Industrial Source Complex Short Term (ISCST) and the COMPLEX I (VALLEY) air dispersion models. The models use the frequency of wind patterns to determine concentration estimates. Therefore, the following site characteristics were evaluated:

* The E. W. Brown plant is located in Mercer county which is classified as attainment for all criteria pollutants.
* Five year surface weather data (1983-1987) measured at Lexington, Kentucky and upper air records from Dayton, Ohio are representative of the meteorological patterns.
* The typing scheme from Land Use Procedure was used to classify the area as rural. This classification was used to determine the mixing heights.
* Terrain elevations were considered since the terrain is above the elevation of the station.
* The BREEZE WAKE program was used to show the effects of existing buildings on the existing stacks of the E. W. Brown station.
* A receptor grid was developed to define the significant impact area.

IV. AIR QUALITY ANALYSIS (CONTINUED)

The modeled results indicate the predicted concentrations of NO_2, PM/PM_{10}, and CO do not have significant impacts on the ambient air quality (TABLE IV.1). Thus, a full impact analysis is not required for these pollutants. However, the maximum annual, 24-hour, and 3-hour average impacts of SO_2 emissions are above the significant impact levels and thus, require further review.

TABLE IV.1

Pollutant	Predicted Concentration from proposal (ug/m^3)	Significant Ambient Impact Concentrations	Significant Monitoring Concentrations
PM/PM_{10}			
Annual	0.20	1.0	NA
24-Hour	2.0	5.0	10.0
CO			
1-Hour	21.2	2000	NA
8-Hour	5.3	500	575
NO_2			
Annual	0.26	1.0	14
SO_2			
Annual	1.24	1.0	NA
24-Hour	12.7	5	13.0
3-Hour	44.2	25	NA
Beryllium			
24-Hour	0.0001	NA	0.001

The proposed turbines are the only PSD increment consuming source in the PSD Class II increment air quality impact assessment. Therefore, the baseline dates for the emissions of PM/PM_{10}, SO_2, and NO_2 were established with the submittal of the complete PSD application by Kentucky Utilities on July 12, 1991. However, since the annual impact of PM/PM_{10}, and NO_2 are each below 1.0 ug/m^3, this application does not establish a baseline area nor could a baseline concentration be determined. Results of the modeled emissions of SO_2, NO_2, and PM/PM_{10} indicated that the maximum predicted concentrations were less than their respective allowable PSD increment (TABLE IV.2).

TABLE IV.2

Pollutant	Predicted Concentration (ug/m^3)	Maximum PSD Increment Available (ug/m^3)
PM/PM_{10}		
Annual	0.20	19
24-Hour	2.0	37
NO_2		
Annual	0.26	25
SO_2		
Annual	1.24	20
24-Hour	12.7	91
3-Hour	44.2	512

Sulfur dioxide emissions from the proposed turbines, natural background concentrations, and emissions from surrounding major sources were combined to compare to the NAAQS compliance concentrations. To determine which major sources in the area contribute significantly to the SO_2 emissions, the sources were reviewed by the "20 D" method. The "20 D" method excludes from the air quality analysis, any major source where the emission rate in tons per year divided by the distance in miles from the proposed source is less that 20. These sources are listed in Table 4-3 of the application. Representative background concentrations were obtained from air quality data collected from the air monitor located on Newtown Pike Road in Lexington, Kentucky. A comparison of maximum SO_2 concentrations to the NAAQS indicated exceedances of the 3 and 24-hour NAAQS concentrations (TABLE IV.3).

TABLE IV.3

Pollutant	Estimated Natural Background (ug/m^3)	Combined Source Impact (ug/m^3)	Maximum Ground Level Concentration (ug/m^3)	NAAQS (ug/m^3)
SO_2				
Annual	15.7	44.2	59.9	80.0
3-hour second-highest	104.8	2781.7	2886.5	1300.0
24-hour second-highest	55.0	389.9	444.9	365.0

Although the NAAQS is predicted to be exceeded, a detailed modeling analysis indicated that the proposed turbines would not have a significant impact on the modeled exceedances of SO_2. It was determined from a further review that the existing sources at the E. W. Brown plant were the predominant source of SO_2 concentrations. Therefore, it is the intent of Kentucky Utilities to demonstrate compliance with the NAAQS prior to the operation of the proposed turbines through the use of one or more of the following options:

* Revise and reduce the SIP emission limitations.
* Increase the stack height to GEP stack height.
* Refine the air dispersion model to include wind-direction-dependent building dimensions.

The nearest Class I area is Mammoth Cave National Park located 125 kilometers from the station. The predicted concentrations from the proposal will not have a significant impact on this area and no adverse effects are expected. No preconstruction monitoring was required for the emissions of PM/PM_{10}, SO_2, NO_2, CO, Be, Pb, or Hg since the predicted concentration increase of each pollutant was below the respective monitoring de minimis concentration (TABLE IV.1). However, preconstruction monitoring is required for ozone since the source has a potential to emit greater than 40 tons per year of VOC. In lieu of onsite monitoring, Kentucky Utilities used representative concentrations from the State maintained and operated ozone monitor located on Iron Works Pike in Fayette County. This monitor has indicated compliance with the ambient air quality standard for the three previous years (1988, 1989, and 1990) and was considered representative of ozone formation in the area.

Analyses made by the applicant for the impacts of this construction on general growth, soil, vegetation, and visibility demonstrate that no adverse effects are expected. The construction activity will generate a minor amount of fugitive dust and emissions from the transportation and construction vehicles. The main concern will result from the generated particulate during construction. However, these emissions during construction are not subject to PSD and are not expected to be visible outside the boundaries of the E. W. Brown Station. Also, minor industrial, commercial, and residential growth of the area is expected due to the modification. As previously discussed, the proposal will not have a significant impact on the NAAQS. The pollutants generated are criteria pollutants and the increases in ambient concentrations are insignificant. Therefore, no adverse effects to the soil or vegetation are expected. Results from the Level I screening procedure obtained from the "Workbook for Plume Visual Impact Screening and Analysis", indicated emission impacts below the screening criteria. Therefore, no visibility impact is expected.

V. CONTROL TECHNOLOGY AND ECONOMIC ANALYSIS

A major modification subject to PSD must conduct a Best Available Control Technology (BACT) analysis for each pollutant that has a significant net emission increase as defined in the Clean Air Act. A BACT requirement is defined as the maximum degree of reduction of a pollutant subject to PSD taking into account energy, environmental, and economic impacts. This is achievable through the application of production processes or available methods, systems, and techniques, including fuel cleaning, treatment, or innovative fuel combustion techniques. However, a recommended control technology must at least meet the most stringent standards of either the New Source Performance Standards or the National Emissions for Hazardous Air

V. CONTROL TECHNOLOGY AND ECONOMIC ANALYSIS (CONTINUED)

Pollutants. BACT is determined on a case-by-case basis using the top-down method to rank available control technology. This construction is subject to a BACT review for PM/PM_{10}, Be, SO_2, NOx, CO, and VOC. The applicant consulted the BACT/LAER Clearinghouse, recent permit applications, US EPA air permitting authorities, and the proposed vendors for associated BACT implementation of stationary turbines. The results are as follows:

PM/PM_{10}/Beryllium

Wet scrubbers, baghouses, electrostatic precipitators, and good combustion practices were reviewed as control devices. Due to the physical construction of the turbines and the engineering principles involved, wet scrubbers, baghouses, and electrostatic precipitators were eliminated as technically feasible controls. Hence, the good combustion control practice was evaluated as the most effective control option.

SO_2

Strategies considered for SO_2 emissions were low sulfur content fuel or flue gas desulfurization by wet or dry scrubbers. The applicant demonstrated that wet scrubbers are technically, economically, and environmentally infeasible methods due to the large flow rate and high temperature of the exhaust stream. Similarly, the use of dry scrubbers was shown as technically and economically infeasible control. BACT for SO_2 is a fuel oil with a maximum sulfur content of 0.3 percent.

CO AND VOC

Catalytic oxidation and good combustion control efficiency were reviewed as control options. The catalyst oxidation is not technically feasible for oil fired combustion turbines since the catalyst could become poisoned by other contaminants and the creation of sulfuric acid. Therefore, good combustion control practices was determined to be BACT.

NOx

Control techniques reviewed for NOx emissions were ammonia injection, flue gas recycle, selective catalytic reduction, and water injection. Ammonia injection and flue gas recycle are both technically infeasible controls since the turbines do not have an adequate temperature zone or resistance time. Selective catalytic reduction is a technically and environmentally infeasible method of control due to the high exhaust temperatures, formation of by products, and the varying temperatures of the exhaust gas during operation. Water injection was selected as BACT.

A detailed analysis of the BACT review is located in Section 2.3 of the application and it is considered to be an adequate demonstration of BACT.

VI. DISCUSSION, CONCLUSION, AND RECOMMENDATION

Approval of this permit is contingent on air quality related considerations as well as the other considerations listed in the executive summary. Pollutant emissions must be modeled to ensure that they will either not be significant or will not cause ground level concentrations which exceed the national ambient air quality standards. A dispersion analysis has been performed by Kentucky Utilities, and this analysis indicates that the increases in ambient ground level concentrations will not be significant.

Although the proposed construction is approvable because ground level impacts are not significant, the recommended permit will require that other adjustments be made to the plant to ensure compliance with the SO_2 NAAQS prior to startup of the new units. Since all other requirements will also be met, it is the writer's recommendation that a permit to construct be issued subject to resolution of any adverse comments that may be received.

APPENDIX A
DRAFT CONSTRUCTION PERMIT

Natural Resources and Environmental Protection Cabinet
Kentucky Department for Environmental Protection
Division for Air Quality

PERMIT

DRAFT COPY

KENTUCKY UTILITIES COMPANY
One Quality Street
Lexington, Kentucky 40507

RE: Construction of combustion turbines at the E.W. Brown Station located on Curdsville Road in Mercer County, Kentucky.

Pursuant to your application which was determined to be complete by this office on July 12, 1991, the Natural Resources and Environmental Protection Cabinet issues this permit for the construction of the equipment specified herein in accordance with the plans, specifications, and other information submitted with your application. This permit has been issued under the provisions of KRS Chapter 224.033 and regulations promulgated pursuant thereto and is subject to all conditions and operating limitations contained herein. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet and/or other state, federal, and local agencies.

POINT OF EMISSION	AFFECTED FACILITY	CONDITIONS
06 (CT04-CT11)	Eight, #2 oil-fired turbines	1. 21,520 maximum horsepower at ISO standard conditions, each. 2. Sulfur content of the fuel oil shall not exceed 0.30 percent by weight. 3. Nitrogen oxide emissions from each turbine shall not exceed 65 ppm at 15 percent oxygen and on a dry basis. 4. Maximum annual operation for each turbine shall not exceed 2500 hours.

DRAFT COPY

No deviation from the plans and specifications submitted with your application or the conditions specified herein is permitted, unless authorized in writing by the Division for Air Quality. Violations of the terms and conditions contained herein shall be grounds for the Department to seek revocation of this permit. All rights of inspection by the representatives of the Division for Air Quality are reserved. Responsibility for satisfactory conformance with all Air Quality Regulations must be borne by the permittee.

PERMIT NUMBER: C-91-128

FILE NUMBER: 102-2740-0001

REGION: Bluegrass

COUNTY: Mercer

SIC CODE: 4911

Issued this ______ day of ______ 19

DRAFT COPY

Hisham M. Saaid, Acting Director

William C. Eddins, Commissioner

DEP7001 (7-90)

PERMIT NUMBER: C-91-128

DRAFT COPY

PERMIT - Continued

GENERAL CONDITIONS:

1. The owner and/or operator of the affected facilities specified on this permit shall furnish to the Division for Air Quality the following:
   a) Written notification, postmarked within 15 days, of the date construction commenced. (See Condition 2)
   b) Written notification of the actual date of start-up and the date of achieving the maximum production rate of each of the affected facilities listed on this permit. This notification must be postmarked within 15 days after each of the above mentioned events or within 15 days after the issuance date of this permit, whichever is later. (See Condition 3)
   c) Within 15 days after demonstration of compliance, an application for a permit to operate. (See Condition 3)

2. Unless construction is commenced on or before eighteen months from the date of this permit or if construction is commenced and then stopped for any consecutive period of eighteen months or more, then this construction permit shall be null and void.

3. a) This construction permit shall allow time for the initial start-up, operation and compliance demonstration of the affected facilities listed herein. However, within 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 owner or operator shall conduct sulfur dioxide and nitrogen oxide performance tests on the gas turbines and furnish the Division a written report of the results of such performance tests.
   b) Unless notification and justification to the contrary are received by this Division, the date of achieving the maximum production rate at which the affected facilities will be operated shall be deemed to be 30 days after initial start-up.
   c) At least 30 days prior to the date of the required performance test(s), the permittee shall complete and return a Compliance Test Protocol (Form DEP6027). The Protocol form shall be utilized by the Division to determine if a pretest meeting is required. The Division shall be notified of the actual test date at least 10 days prior to the tests.

4. Operation of an affected facility is considered to have commenced at any time air pollutants are generated and emitted to the atmosphere by that affected facility.

5. All air pollution control equipment and all air pollution control measures proposed by the application in response to which this permit is issued shall be in place and operational at any time an affected facility is operated.

6. Those affected facilities specified herein whose continued compliance has been demonstrated to the Division's satisfaction are hereby authorized by this permit to operate for 90 calendar days following such compliance demonstration or for such additional period as may be authorized by 401 KAR 50:035, Section 1(2)(c). Authorization for operation provided by 401 KAR 50:035, Section 1(2)(c), shall expire thirty (30) days after the date notification is made to the source by the Department that an operating permit fee balance is due or immediately upon notification to the source by the Department that the source operating permit is denied.

DRAFT COPY

PERMIT NUMBER: C-91-128

DRAFT COPY

PERMIT - Continued

GENERAL CONDITIONS:

7. Those affected facilities specified herein for which compliance has not been demonstrated during the time period specified by General Condition 3 shall not be operated unless authorized in writing by the Director.

8. The permittee shall maintain and make available for inspection by this Division all records necessary to assure that the allowable emission and fuel usage rates will not be exceeded.

9. In no way does this permit relieve the permittee from compliance with all applicable emission and air quality standards.

10. An operating permit cannot be issued for the affected facilities listed on this permit unless the remainder of the source's affected facilities are either in compliance, shut down, or on an approved compliance schedule.

11. The sulfur content of the fuel fired in the turbine shall be monitored and reported to this Division by methods specified in Section 60:334 of 40 CFR 60, Subpart GG, as referenced by 401 KAR 59:019.

12. Nitrogen oxide and sulfur dioxide emission limitations specified for the #2 fuel oil combustion turbines, emission point 06(CT04-CT11), shall be as measured by methods specified in Section 60:335 of 40 CFR 60, Subpart GG, as referenced by 401 KAR 59:019.

13. Monitoring and reporting requirements for the #2 fuel oil combustion turbines shall be conducted as specified in Section 60:334 of 40 CFR 60, Subpart GG, as referenced by 401 KAR 59:019.

14. Prior to the startup of the affected facilities authorized by this permit, the permittee shall demonstrate through existing plant emission reductions, refined modeling, or other measures approved by the Division, compliance with the National Ambient Air Quality Standard for Sulfur Dioxide.

DRAFT COPY

CONCERNING THE CONSTRUCTION OF EIGHT, COMBUSTION TURBINES
AT THE E.W. BROWN STATION LOCATED
IN MERCER COUNTY, KENTUCKY

Kentucky Utilities Company has applied to the Division for Air Quality for a permit to construct eight, simple cycle combustion turbines at their existing E.W. Brown Generating Station in Mercer County, Kentucky.

The application will be subject to the New Source Performance Standards (NSPS) and to the Prevention of Significant Deterioration (PSD) of Air Quality provisions of the Clean Air Act which requires the use of Best Available Control Technology. The application's proposed use of good combustion control practices for particulate, beryllium, carbon dioxide, and volatile organic compounds; 0.3% sulfur content low sulfur fuel oil for sulfur dioxide; and water injection for the control of nitrogen oxides have been analyzed and concluded to be the Best Available Control Technology. Although the ground level concentration of sulfur dioxide is predicted by dispersion modeling to exceed the National Ambient Air Quality Standard, the project may be permitted since the permit will require actions by the applicant to correct the predicted exceedance prior to the startup of the facilities authorized by the permit. Furthermore, since ground level concentrations are predicted to be less than regulatory defined significant concentrations, the project is approvable without the above corrections. Additionally, the predicted consumption of the remaining increments for Prevention of Significant Deterioration of Air Quality has been determined through dispersion modeling and the results are tabulated below:

POLLUTANT	INCREMENT CONSUMPTION (ug/m3)	MAXIMUM INCREMENT AVAILABLE (ug/m3)
SO2		
Annual	1.24	20
24-Hour	12.7	91
3-Hour	59.1	512
PM		
Annual	0.20	19
24-Hour	2.0	37
NO2		
Annual	0.26	25

Since the Cabinet has concluded that the proposed construction will comply with all applicable requirements, a preliminary determination has been made to issue the permit to construct. Copies of this determination are available for inspection during normal business hours at the following locations:

Natural Resources and Environmental Protection Cabinet
Division for Air Quality
316 St. Clair Mall
Frankfort, Kentucky 40601

and

County Clerk's Office
Mercer County Courthouse Annex
Harrodsburg, Kentucky 40330

Any member of the general public who considers himself affected by this source, on the basis of air quality, is invited to make written comments and may request a public hearing. To be considered, any comments or requests for public hearing must be postmarked within thirty (30) days of the date of this notice, and should be addressed to Mr. Roger S. Cook, Natural Resources and Environmental Protection Cabinet, Division for Air Quality, 316 St. Clair Mall, Frankfort, Kentucky 40601. Any comments received will be considered in the Cabinet's Final Determination to grant or deny the permit.

ATTACHMENT B

KU Response and Forms provided to KYDAQ

in Support of Combusting with Natural Gas as a Result of Comments filed by KU

KENTUCKY UTILITIES COMPANY
ONE QUALITY STREET
LEXINGTON, KENTUCKY
40507
TELEPHONE 606-255-2100

November 21, 1991

Mr. James W. Dills, Manager
Permit Review Branch
Division for Air Quality
316 St. Clair Mall
Frankfort, KY 40601

Re: Modification to Permit No. 0-86-68
E. W. Brown Generating Station
Mercer County, Kentucky

Dear Mr. Dills:

Kentucky Utilities Company (KU) is providing the following information in response to the Division for Air Quality's (DAQ) request for information concerning the combustion of natural gas as a fuel for KU's proposed combustion turbine installation. KU has attached completed Forms DEP7007B and DEP7007N to provide the DAQ with 1) the maximum hourly and annual natural gas fuel usage rates and 2) the maximum hourly and annual emission rates for each vendor's machine. This data has been supplied for the ABB and Westinghouse machines, as they are currently the remaining vendors under consideration by KU for the peaker installation at E. W. Brown.

Please note that for each pollutant emitted, the emissions from the combustion turbines when burning natural gas are less than those resulting when the turbines are being fired with No. 2 fuel oil. Since the air quality modeling analysis in our original PSD application was based on the worst case emissions generated by the turbines when operating at maximum conditions while firing No. 2 fuel oil (the "dirtier" fuel), a re-evaluation of the modeling analysis using the emissions resulting from the combustion of natural gas is not necessary.

In addition, you requested BACT determinations for each pollutant subject to PSD based on natural gas usage. A summary of this information is provided in the original PSD permit application (dated June 12, 1991) in Table 2-3 with the detailed BACT discussion for each pollutant occurring on pages 9 through 16 of the document.

If you have any questions concerning this information, please feel free to contact me at 606/255-2100.

Very truly yours,

Caryl M. Pfeiffer

Caryl M. Pfeiffer
Manager, Environmental Services

CMP:dmh

DEP7007B Imber

MANUFACTURING OR PROCESSING OPERATIONS

Department for Environmental Protection
DIVISION FOR AIR QUALITY
(Please read instructions before completing this form)

EMISSION POINT NO. (1)	PROCESS DESCRIPTION (2)	CONTINUOUS OR BATCH (3)	MAXIMUM OPERATING SCHEDULE *(Hours/Day, Days/Week, Weeks/Year)* (4) A	PROCESS EQUIPMENT *(Make, Model, Etc.)* (5)	DATE INSTALLED (6)
CT04 CT05 CT06 CT07 CT08 CT09 CT10 CT11	Electric Generation	C	2500 hrs/yr	ABB GT 11N2 Combustion Turbine or Westinghouse W501D Combustion Turbine	4/94(1) 4/95(3) 4/96(1) 4/97(1) 4/98(1) 4/99(1)

EMISSION POINT NO. (1)	LIST RAW MATERIAL(S) USED (7)	MAXIMUM QUANTITY INPUT OF EACH RAW MATERIAL *(Specify Units/Hour)* (8) A,B	TYPE OF PRODUCTS (9)	QUANTITY OUTPUT *(Specify Units)* MAXIMUM HOURLY (Specify Units) (10a) A	QUANTITY OUTPUT *(Specify Units)* MAXIMUM ANNUAL (Specify Units) (10b) A
CT04-CT11	ABB Water	Approximately 99,000 lb/hr	Electric Energy	137,440 KW	343.6×10^6 KWH
CT04-CT11	West. Water	73,930 lb/hr	Electric Energy	128,380 KW	320.95×10^6 KWH

A. Per CT
B. May vary depending on degree of NOx control required.

DEP7007B
Continued

IMPORTANT: Complete DEP7007N for Air Pollution Control Equipment. If there is no control equipment, complete only Section 1 of DEP7007N.

EMISSION POINT NO. (1)	FUEL TYPE FOR PROCESS HEAT (11)	RATED BURNER CAPACITY (BTU/HOUR) (12)	FUEL COMPOSITION		FUEL USAGE RATES		NOTE: If the combustion products are emitted along with the process emissions, indicate so in this column by writing "combined."
			% SULFUR (13a)	% ASH (13b)	MAXIMUM HOURLY (14a) A	MAXIMUM ANNUAL (14b) A	
West. CT04-11	Natural Gas	1325×10^6	Nil	Nil	1.274×10^6 Cu.Ft.	2,867 BCF	
ABB CT04-11	Natural Gas	1463×10^6	Nil	Nil	1.408×10^6 Cu.Ft.	3,168 BCF	

A. Per CT

16. On a separate sheet, make a complete list of all wastes generated by each process *(e.g.: wastewater, scrap, rejects, cleanup wastes, etc.)*. List the hourly *(or daily)* and annual quantities of each waste and the method of final disposal.

Demineralizer regen. water, approx. 30×10^6 gal/yr discharged to ash treatment basin. Area and roof stormwater runoff routed to oil/water separator and ultimately discharged to Herrington Lake. Miscellaneous floor drains routed to oil/water separator, discharged to ash treatment. basin.

17. IMPORTANT: Submit a process flow diagram. Label all materials, equipment and emission point numbers.

18. Material Safety Data Sheets with complete chemical compositions are required for each process.

SECTION I. SUMMARY SHEET (*Make additional copies, if necessary*)

Emission Point Number	Facility Description(s)	Control Equipment [1] A			Stack Parameters A, B					Control Efficiency %	Capture [3] or Collection Efficiency %	Basis of Estimate
		Type	Date Installed	Cost $ C	Height ft.	Diameter [2] ft.	Temp. °F	Flow ACFM	Exit Velocity ft/sec.			
CT 04-11	West.	Water Inj.	4/94	2 Mill.	170'	16.4	950	1.97×10^6	155	-------	------	-------
CT04-11	ABB	Water Inj.	4/94	2 Mill.	170'	16.4	875	2.08×10^6	164	-------	------	-------

1. If a facility has secondary control equipment in addition to primary control equipment, use a separate line and indicate, under type, that it is a secondary control.
2. If the stack is rectangular, specify the dimensions. If there is no stack for a particular point, enter the minimum height of release under 'Height' and write NA (Not Applicable) under 'Diameter'.
3. Capture or collection efficiency is the efficiency with which the pollutants are collected at the emission source before being sent to the control device.

(REVISED 5/87)

A. Per CT B. Stack parameters determined at new base elevation and orientation.

DEP7007N
Continued

EMISSION POINT NO.	NAME AND CHEMICAL COMPOSITION OF POLLUTANTS		GRAIN LOADING (Grains/SCF at 68°F) A		AMOUNT EMITTED A		BASIS OF ESTIMATE (Attach copies of calculations)
			INLET	OUTLET	MAXIMUM Lb/Hr.	MAXIMUM Tons/Yr.	
CT04-11	SO2	West.	NA	0	0	0	Manufacturer's data and calculations.
	NOx		NA	0.035	222	250	
	TSP		NA	.0007	4.4	5	
	PM10		NA	.0007	4.4	5	
	CO		NA	0.0117	74	83	
CT04-11	SO2	ABB	NA	0	0	0	
	NOx		NA	0.0355	251	282	
	TSP		NA	0.0014	10	11	
	PM10		NA	0.0014	10	11	
	CO		NA	0.0038	27	30	

A. Per CT

SECTION I. (CONTINUED)

The basis for all efficiency estimates should be given and supported with documentation and a detailed explanation of the method of calculation and/or the source of information. Submit all pertinent drawings.

Describe briefly the disposal of particulates collected, scrubbing liquid, and/or other wastes generated at the plant site:

____

____

SECTION II. SPECIFIC CONTROL EQUIPMENT

ADSORPTION UNIT

1. EMISSION POINT NUMBER OF ADSORPTION UNIT:

2. MANUFACTURER

3. MODEL NAME & NUMBER

4. ADSORBENT:

Activated Charcoal: Type __________ Other *(specify)* __________

5. ADSORBATE(S):

6. NUMBER OF BEDS:

7. WEIGHT OF ADSORBENT PER BED:

__________ lb.

8. DIMENSIONS OF BED:

Thickness in direction of gas flow __________ inches: Cross-section area __________ sq. inches

9. INLET GAS TEMPERATURE

__________ °F or __________ °C

10. PRESSURE DROP ACROSS UNIT:

__________ inch water gauge

11. TYPE OF REGENERATION:

☐ Replacement ☐ Steam ☐ Other *(specify)*: __________

12. METHOD OF REGENERATION:

☐ Alternate use of beds ☐ Source shut down ☐ Other *(specify)*: __________

13. TIME ON LINE BEFORE REGENERATION:

__________ minutes

14. EFFICIENCY OF ADSORBER:

__________ %

Fuel Usage Rates *

Max Hourly: West = 1325 x 10^6 Btu/HR x MCF/1040 Btu = 1274 x 10^6 CF/HR

ABB = 1463 x 10^6 Btu/HR x MCF/1040 Btu = 1408 x 10^6 CF/HR

Max Annual: West = 1.274 x 10^6 CF/HR x (2500 HR/YR x 0.90) = 2867 BCF/YR

ABB = 1.408 x 10^6 CF/HR x (2500 HR/YR x 0.90) = 3168 BCF/YR

* Based on Natural Gas energy content of 1040 Btu/MCF

Emissions

Grain Loading:

West. SCFM = 1.97 x 10^6 ACFM $\frac{460+68}{460+949}$ = 738,226 SCFM

NO_x = 222 LB/HR x HR/60 min x min/738,226 SCF x 7000 GR/LB

= 0.035 GR/SCF

TSP & PM10 = 4.4 LB/HR x HR/60 min x min/738,226 SCF x 7000 GR/LB

= 0.0007 GR/SCF

CO = 74 LB/HR x HR/60 min x min/738,220 SCF x 7000 GR/LB

= 0.0117 GR/SCF

ABB SCFM = [984 M^3/S x 35.31 ft^3/M^3 x 60 sec/min] $\frac{460+68}{460+873}$

= 825,748 SCFM

NO_x = 251 LB/HR x HR/60 min x min/825,748 SCF x 7000 GR/LB

= 0.0355 GR/SCF

TSP & PM10 = 10 LB/HR x HR/60 min x min/825,748 SCF x 7000 GR/LB

= 0.0014 GR/SCF

CO = 27 LB/HR

= 0.0038 GR/SCF

ATTACHMENT C

Final Determination to Construct issued by KyDAQ

PHILLIP J. SHEPHERD
SECRETARY

BRERETON C. JONES
GOVERNOR

COMMONWEALTH OF KENTUCKY
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION CABINET
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
DIVISION FOR AIR QUALITY
316 St. Clair Mall
Frankfort, Kentucky 40601

March 10, 1992

Ms. Caryl M. Pfeiffer, Manager
Environmental Services
Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

RE: E.W. Brown Generating Station
I.D. #102-2740-0001
Log #B415

Dear Ms. Pfeiffer:

Enclosed is a copy of the final determination performed by this Division for the proposed simple cycle combustion turbines to be constructed at the E.W. Brown Generating Station.

If you have any questions, please contact this office at (502) 564-3382.

Sincerely,

James W. Dills, Manager
Permit Review Branch

JWD/ALW/hnh

Enclosure

cc: Bluegrass Regional Office

FINAL DETERMINATION ON THE APPLICATION OF

KENTUCKY UTILITIES COMPANY
E.W. Brown Generating Station

To Construct

Eight, simple cycle combustion turbines at their existing generating station located on Curdsville Road in Mercer County, Kentucky

Review and Analysis By:

Andrea L. Wilson

March 10, 1992

EIS NUMBER:	102-2740-0001	SIC CODE:	4911
REGION:	Bluegrass	COUNTY:	Mercer
LOG NUMBER:	B415	DATE COMPLETE:	July 12, 1991
UTM COORDINATES:	700.6E, 4184.8N Zone 16	TYPE OF REVIEW:	PSD, NSPS, and NSR

DIVISION FOR AIR QUALITY
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION CABINET
316 ST. CLAIR MALL
FRANKFORT, KENTUCKY 40601

TABLE OF CONTENTS

I. Final Determination

On June 14, 1991, the Kentucky Division for Air Quality received a complete application from the Kentucky Utilities Company for the construction of eight, #2 fuel oil/natural gas fired, simple cycle combustion turbines. Each unit will have a maximum heat input of 1500 mmBTU/hour and will be used to meet the power supply of the systems peak load requirements. A Prevention of Significant Deterioration (PSD) review applies since the source is major and there will be a significant net emission increase for sulfur dioxide (SO_2), nitrogen oxides (NO_x), total suspended particulate (PM/PM_{10}), carbon monoxide (CO), beryllium (Be), and volatile organic compounds (VOC) which constitutes a major modification. Additionally, this proposal is subject to the New Source Performance Standards (NSPS) for NO_x and SO_2 since the heat input of the turbines is greater than 10.0 mmBTU/hour.

The review of the application demonstrated that the Best Available Control Technology (BACT) has been proposed for the control of sulfur dioxide, nitrogen oxides, total suspended particulate, carbon monoxide, beryllium, and volatile organic compounds. Since BACT limits for PM, CO, VOC, SO_2 and beryllium were omitted from the Preliminary Determination, they have been added to the Final Determination. Results of the air quality modeling analyses indicated that the maximum predicted concentration of each pollutant was less than the respective allowable PSD increment. The National Ambient Air Quality Standard (NAAQS) is predicted to be exceeded for SO_2 emissions. However, a detailed modeling analysis indicated that the proposed construction of the turbines would not have a significant impact on the modeled exceedences of sulfur dioxide. A further review revealed the existing sources at the E.W. Brown plant as the predominant source of SO_2 concentrations. It is the intent of Kentucky Utilities to demonstrate compliance with the NAAQS prior to the operation of the proposed turbines. Therefore, the project may be permitted since the permit will require actions by the applicant to correct the predicted exceedance prior to the start up of the facilities.

A preliminary determination was made to approve the permit and a public notice was placed in the Harrodsburg Herald on September 26, 1991. Written comments were received from Mrs. Zoe Strecker and Kentucky Utilities concerning these documents. The following is a discussion and consideration of comments from both parties:

Comments received from Kentucky Utilities:

1. Kentucky Utilities requested each turbine be conditioned by a maximum heat input of 1500 mmBTU/hour instead of a rated capacity of 21,520 Hp.

   Division's Reply:

   The Division acknowledges Kentucky Utilities concern regarding this permit condition. Since pollutant emission rates are a function of heat input rate rather than power output, the permit has been revised accordingly.

2. Kentucky Utilities plans to pursue a supply of natural gas for the E.W. Brown Station. Therefore, KU request the permit include a dual fuel usage of natural gas in addition to the conditioned usage of #2 fuel oil.

Division's Reply:

This request prompted the Division to solicit additional information on November 5, 1991, for the natural gas usage. A response was received from KU on November 21, 1991, providing the necessary information to make a determination on the natural gas. From this information, it was determined that the turbines could be conditioned to fire both natural gas and/or #2 fuel oil. Also, the Best Available Control Technology (BACT) will remain as determined in the preliminary determination since the worst case emissions are generated from the #2 fuel oil.

Comments received from Mrs. Zoe Strecker:

1. Mrs. Strecker inquired about the fuel generally used for these types of turbines and why the Division had not compared emission calculations for natural gas to those of #2 fuel oil. Additionally, she was concerned about the public's lack of knowledge concerning the construction project and inquired as to whether an informational meeting could be held. Finally, she voiced her concern about the sulfur dioxide emissions generated from the project.

Division's Reply:

In response to Mrs. Strecker's comments and in addition to KU's request, the Division has reviewed and compared emissions from the natural gas and the #2 fuel oil. It was confirmed that the county clerk's office did obtain a copy of the preliminary determination as stated in the newspaper advertisement. Once this document was found, Mrs. Strecker withdrew her requested informational meeting. It was determined in the preliminary determination that the sulfur dioxide emissions from the construction alone would not exceed the NAAQS and the permit would be contingent on the reduction of sulfur dioxide emissions from the existing E. W. Brown facilities so that the sulfur dioxide NAAQS would not be exceeded.

2. Several of Mrs. Strecker's questions were not directly related to air quality concerns and were addressed directly to her by KU in a letter dated October 30, 1991.

In conclusion, a thorough analysis has been made of all relevant information available which pertains to this application. This Division has concluded that the proposed construction will comply with all applicable Division for Air Quality Regulations and requirements. Therefore, a final determination has been made to issue a permit to construct subject to the conditions of the permit.

II. Construction Permit

Natural Resources and Environmental Protection Cabinet
Kentucky Department for Environmental Protection
Division for Air Quality

PERMIT

KENTUCKY UTILITIES COMPANY
One Quality Street
Lexington, Kentucky 40507

RE: Construction of combustion turbines at the E.W. Brown Station located on Curdsville Road in Mercer County, Kentucky.

Pursuant to your application which was determined to be complete by this office on July 12, 1991, the Natural Resources and Environmental Protection Cabinet issues this permit for the construction of the equipment specified herein in accordance with the plans, specifications, and other information submitted with your application. This permit has been issued under the provisions of KRS Chapter 224.033 and regulations promulgated pursuant thereto and is subject to all conditions and operating limitations contained herein. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet and/or other state, federal, and local agencies.

POINT OF EMISSION	AFFECTED FACILITY	CONDITIONS
06 (CT04-CT11)	Eight, #2 oil-fired/ natural gas turbines	1. 1500 mm/BTU maximum heat input at ISO standard conditions, each. 2. Sulfur content of the fuel oil shall not exceed 0.30 percent by weight. Sulfur dioxide emissions shall not exceed 444 lbs/hour and 555 tons/year, each.

No deviation from the plans and specifications submitted with your application or the conditions specified herein is permitted, unless authorized in writing by the Division for Air Quality. Violations of the terms and conditions contained herein shall be grounds for the Department to seek revocation of this permit. All rights of inspection by the representatives of the Division for Air Quality are reserved. Responsibility for satisfactory conformance with all Air Quality Regulations must be borne by the permittee.

PERMIT NUMBER: C-92-005
FILE NUMBER: 102-2740-0001
REGION: Bluegrass
COUNTY: Mercer
SIC CODE: 4911

Issued this 10th day of March 1992

Hisham M. Saaid

Hisham M. Saaid, Acting Director

William C. Eddins

William C. Eddins, Commissioner

DEP7001 (7-90)

PERMIT NUMBER: C-92-005

PERMIT - Continued

POINT OF EMISSION	AFFECTED FACILITY	CONDITIONS
		3. Nitrogen oxide emissions from each turbine shall not exceed 65 ppm at 15 percent oxygen and on a dry basis when burning #2 fuel oil and shall not exceed 42 ppm at 15 percent oxygen and on a dry basis when burning natural gas.
		4. Carbon monoxide emissions shall not exceed 75 lbs/hour and 93.8 tons/year, each.
		5. Particulate emissions shall not exceed 67 lbs/hour and 83.8 tons/year, each.
		6. Volatile organic compound emissions shall not exceed 20.4 lbs/hour and 25.5 tons/year, each.
		7. Beryllium emissions shall not exceed 3.37E-03 lb/hour and 4.21E-03 ton/year, each.
		8. Maximum annual operation for each turbine shall not exceed 2500 hours.

GENERAL CONDITIONS:

1. The owner and/or operator of the affected facilities specified on this permit shall furnish to the Division for Air Quality the following:
   a) Written notification, postmarked within 15 days, of the date construction commenced. (See Condition 2)
   b) Written notification of the actual date of start-up and the date of achieving the maximum production rate of each of the affected facilities listed on this permit. This notification must be postmarked within 15 days after each of the above mentioned events or within 15 days after the issuance date of this permit, whichever is later. (See Condition 3)
   c) Within 15 days after demonstration of compliance, an application for a permit to operate. (See Condition 3)

2. Unless construction is commenced on or before eighteen months from the date of this permit or if construction is commenced and then stopped for any consecutive period of eighteen months or more, then this construction permit shall be null and void.

PERMIT NUMBER: C-92-005

PERMIT - Continued

GENERAL CONDITIONS:

3. a) This construction permit shall allow time for the initial start-up, operation and compliance demonstration of the affected facilities listed herein. However, within 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 owner or operator shall conduct sulfur dioxide and nitrogen oxide performance tests on the gas turbines and furnish the Division a written report of the results of such performance tests.
   b) Unless notification and justification to the contrary are received by this Division, the date of achieving the maximum production rate at which the affected facilities will be operated shall be deemed to be 30 days after initial start-up.
   c) At least 30 days prior to the date of the required performance test(s), the permittee shall complete and return a Compliance Test Protocol (Form DEP6027). The Protocol form shall be utilized by the Division to determine if a pretest meeting is required. The Division shall be notified of the actual test date at least 10 days prior to the tests.

4. Operation of an affected facility is considered to have commenced at any time air pollutants are generated and emitted to the atmosphere by that affected facility.

5. All air pollution control equipment and all air pollution control measures proposed by the application in response to which this permit is issued shall be in place and operational at any time an affected facility is operated.

6. Those affected facilities specified herein whose continued compliance has been demonstrated to the Division's satisfaction are hereby authorized by this permit to operate for 90 calendar days following such compliance demonstration or for such additional period as may be authorized by 401 KAR 50:035, Section 1(2)(c). Authorization for operation provided by 401 KAR 50:035, Section 1(2)(c), shall expire thirty (30) days after the date notification is made to the source by the Department that an operating permit fee balance is due or immediately upon notification to the source by the Department that the source operating permit is denied.

7. Those affected facilities specified herein for which compliance has not been demonstrated during the time period specified by General Condition 3 shall not be operated unless authorized in writing by the Director.

8. The permittee shall maintain and make available for inspection by this Division all records necessary to assure that the allowable emission and fuel usage rates will not be exceeded.

9. In no way does this permit relieve the permittee from compliance with all applicable emission and air quality standards.

10. An operating permit cannot be issued for the affected facilities listed on this permit unless the remainder of the source's affected facilities are either in compliance, shut down, or on an approved compliance schedule.

PERMIT NUMBER: C-92-005

PERMIT - Continued

GENERAL CONDITIONS:

11. The sulfur content of the fuel fired in the turbine shall be monitored and reported to this Division by methods specified in Section 60:334 of 40 CFR 60, Subpart GG, as referenced by 401 KAR 59:019.

12. Nitrogen oxide and sulfur dioxide emission limitations specified for the combustion turbines, emission point 06(CT04-CT11), shall be as measured by methods specified in Section 60:335 of 40 CFR 60, Subpart GG, as referenced by 401 KAR 59:019.

13. Monitoring and reporting requirements for the combustion turbines shall be conducted as specified in Section 60:334 of 40 CFR 60, Subpart GG, as referenced by 401 KAR 59:019.

14. Prior to the start-up of the affected facilities authorized by this permit, the permittee shall demonstrate through existing plant emission reductions, refined modeling, or other measures approved by the Division, compliance with the National Ambient Air Quality Standard for Sulfur Dioxide.

15. Particulate, carbon monoxide, beryllium, and volatile organic compound limitations specified herein shall be as measured by Reference Methods 5, 10, 104, and 25 respectively, as referenced in Regulation 401 KAR 50:015, Section 1.

III. Comments Received

366 Coghill Lane
Harrodsburg, Ky 40330
October 16, 1991

Mr. Roger S. Cook
Natural Resources and Environmental Protection Cabinet
Division of Air Quality
316 St. Clair Mall
Frankfort, Ky 40601

102-2740-0001
Cook
Bluegrass

RECEIVED
OCT 19 10 41 AM '91

Dear Mr. Cook:

I am writing in reference to case number 91-115, the proposed constuction by Kentucky Utilities of several simple cycle combustion turbines at the E.W. Brown Generating Station in Mercer County. As the crow flies, I live less than three miles from E.W. Brown and am, therefore, personally interested in air quality concerns. Folks who live in this immediate area are already concerned about the environmental impact of the existing coal-burning generators. Every rainfall, those of us who use cisterns are made painfully aware of the degredation of the air quality here when the soot on our roofs washes down the gutters and, if we aren't home to let the roof wash first, accumulate in the form of black silt in the bottom of the cisterns.

I would like to know more about the possible impact of burning #2 fuel oil. Is is not true that this sort of turbine is usually fuelled with natural gas? If so, why hasn't a location for these proposed turbines been chosen to which natural gas lines have already been run? Natural gas is readily available in Kentucky and even in this region. The "Preliminary Determination" made by the Department for Environmental Protection (your office) does not compare emissions from natural gas with those from fuel oil. It seems as if the public should have access to such an analysis.

In fact, it seems that the public should be better educated on this entire project. Last week I went in search of K.U.'s application and found that virtually no one in Mercer County knew anything about the proposal. "No one" includes the Judge Executive, the Mayor, the County Clerk, and the County Attorney. There was a public notice run in the paper, but no one seems to have understood the importance of this project--perhaps the notice did not make clear that a citizen could have any effect on the process. Would it be possible to have an informational hearing or an informal educational meeting in Mercer County?

Another concern with the use of #2 oil as a fuel for these jet engine-link turbines is that oil is not a stable supply source. We are still fighting a war in the Middle East for oil. Moreover, the scientific community has serious concerns about sulfur dioxide (and other) emissions, which are responsible in part for the deterioration of the ozone layer, and for acid rain. These become health concerns for all citizens. In what forum can the public address these issues?

I look forward to hearing from you soon, before it's too late to act. In advance, thank you for your help.

Sincerely,

Zoé Strecker

KENTUCKY UTILITIES COMPANY
ONE QUALITY STREET
LEXINGTON, KENTUCKY
40507
TELEPHONE 606-255-2100

RECEIVED
OCT 2 1991

October 25, 1991

Mr. James W. Dills, Manager
Permit Review Branch
Division for Air Quality, KNREPC
316 St. Clair Mall
Frankfort, KY 40601

Re: Draft Permit No. C-91-128

Dear Mr. Dills:

Kentucky Utilities Company (KU) has received and reviewed the Kentucky Division for Air Quality's (DAQ) preconstruction review and preliminary determination on KU's Prevention of Significant Deterioration (PSD) permit application to install eight simple-cycle combustion turbines at the E. W. Brown Generating Station. KU would like to offer the following comments on the draft permit to construct attached to the DAQ's preconstruction review and preliminary determination.

KU's first comment relates to the condition in the draft permit which sets the maximum horsepower limitation for the combustion turbines. KU requests that maximum heat input be used (instead of horsepower) to limit the size of the machines. KU's calculation shows that the maximum heat input for each turbine would be equal to 1500 mmBTU/hr at ISO standard conditions.

KU's other comment relates to the dual fuel capability of the combustion turbines KU has proposed to install. These machines will be able to burn both #2 fuel oil and natural gas. Although natural gas is not currently available at the E. W. Brown site, KU is pursuing a supply and we do not want the DAQ's permit to construct to preclude this option for the combustion turbines. Thus we would request that the DAQ condition the construction permit for the burning of natural gas as well as #2 fuel oil. This could be done by changing the "affected facility" to read: "eight, #2 oil-fired and/or natural gas-fired turbines" and changing condition 3. for point of emission 06 to read: "Nitrogen oxide emissions from each turbine shall not exceed 65 ppm at 15 percent oxygen and on a dry basis when burning #2 fuel oil and shall not exceed 42 ppm at 15 percent oxygen and on a dry basis when burning natural gas."

If you have any questions concerning the above comments, please feel free to contact me at (606) 255-2100.

Very truly yours,

Caryl M. Pfeiffer

Caryl M. Pfeiffer
Manager, Environmental Services

CMP:dmh

RECEIVED

KENTUCKY UTILITIES COMPANY

ONE QUALITY STREET
LEXINGTON, KENTUCKY
40507
TELEPHONE 606-255-2100

October 30, 1991

102-2740-0001
Dills
Bluegrass

Mr. James W. Dills, Manager
Permit Review Branch
Division for Air Quality, KNREPC
316 St. Clair Mall
Frankfort, KY 40601

Dear Mr. Dills:

At the request of your staff, Kentucky Utilities Company (KU) is providing the following information regarding questions raised by Ms. Zoe Strecker in her letter of October 16, 1991 to Mr. Roger Cook of the Kentucky Division for Air Quality. Ms. Strecker voiced some concerns regarding KU's proposal to install simple cycle combustion turbines (to provide peaking power) at the E. W. Brown Generating Station site.

Ms. Strecker is correct that these proposed combustion turbines will have dual fuel capability. These machines will be able to burn either No. 2 fuel oil or natural gas to generate electricity. Although there is no supply of natural gas presently available at the E. W. Brown site (capable of supplying the needs of the proposed combustion turbines), there is a bulk natural gas supply within ten miles of the site. Since KU does not want to preclude this fuel option for the proposed combustion turbines, the Company is pursuing this bulk supply of natural gas. Contacts have been made with the owner of the gas transmission pipelines and discussions have occurred regarding the construction of the required pipeline into the E. W. Brown site. Based on an economic analysis, KU presently believes it will be economical to construct a natural gas pipeline into the site by 1995/1996 (the first of the proposed combustion turbines is scheduled to be in service or operation in 1994).

KU chose to locate the proposed combustion turbines at its existing E. W. Brown Generating Station site because it is the most economical site for the Company to develop for this supply of peaking power, even when considering the costs associated with bringing a natural gas supply into the site. The E. W. Brown site offers significant advantages over other sites investigated by KU for the installation of the proposed combustion turbines including, without limitation: the E. W. Brown site already has skilled personnel readily available to perform the routine maintenance and upkeep needed for the equipment and to resolve any unexpected problems in a timely fashion; the site has a source of purified or demineralized water available for injection into the machines to control NO_x formation during combustion; the site has a rail siding such that equipment can be delivered to the site without added costs; and the site has existing transmission outlets capable of integrating the combustion turbine output into KU's transmission system to load centers reliably and efficiently. Because of these advantages at the E. W. Brown site, the development costs of the site, including the cost to bring natural gas into the site, are less than those development costs which would be incurred at the other sites investigated by KU and others.

Ms. Strecker also raised a concern regarding the public awareness of the installation of the proposed combustion turbines. KU made contact with local and county officials through the Harrodsburg-Mercer County Planning and Zoning Commission, supplying information regarding the project as early as December 1990. KU has also involved the public through the Kentucky Public Service Commission's process to receive Certificates of Convenience and Necessity and Environmental Compatibility and the Kentucky Division for Air Quality's prevention of significant deterioration and new source review procedures. KU has and will continue to supply information regarding the project to these regulatory bodies and the public.

If you have questions regarding the above information, please feel free to contact me at (606) 255-2100.

Very truly yours,

Caryl M. Pfeiffer

Caryl M. Pfeiffer
Manager, Environmental Services

CMP:dmh

RECEIVED
FILE ROOM
Oct 31 2 27 PM '91
DIVISION FOR
AIR QUALITY

KENTUCKY UTILITIES COMPANY
ONE QUALITY STREET
LEXINGTON, KENTUCKY
40507
TELEPHONE 606-255-2100

November 21, 1991

RECEIVED
NOV 21 10 27 AM '91

Mr. James W. Dills, Manager
Permit Review Branch
Division for Air Quality
316 St. Clair Mall
Frankfort, KY 40601

Re: Modification to Permit No. 0-86-68
E. W. Brown Generating Station
Mercer County, Kentucky

Dear Mr. Dills:

Kentucky Utilities Company (KU) is providing the following information in response to the Division for Air Quality's (DAQ) request for information concerning the combustion of natural gas as a fuel for KU's proposed combustion turbine installation. KU has attached completed Forms DEP7007B and DEP7007N to provide the DAQ with 1) the maximum hourly and annual natural gas fuel usage rates and 2) the maximum hourly and annual emission rates for each vendor's machine. This data has been supplied for the ABB and Westinghouse machines, as they are currently the remaining vendors under consideration by KU for the peaker installation at E. W. Brown.

Please note that for each pollutant emitted, the emissions from the combustion turbines when burning natural gas are less than those resulting when the turbines are being fired with No. 2 fuel oil. Since the air quality modeling analysis in our original PSD application was based on the worst case emissions generated by the turbines when operating at maximum conditions while firing No. 2 fuel oil (the "dirtier" fuel), a re-evaluation of the modeling analysis using the emissions resulting from the combustion of natural gas is not necessary.

In addition, you requested BACT determinations for each pollutant subject to PSD based on natural gas usage. A summary of this information is provided in the original PSD permit application (dated June 12, 1991) in Table 2-3 with the detailed BACT discussion for each pollutant occurring on pages 9 through 16 of the document.

If you have any questions concerning this information, please feel free to contact me at 606/255-2100.

Very truly yours,

Caryl M. Pfeiffer

Caryl M. Pfeiffer
Manager, Environmental Services

CMP:dmh

Department for Environmental Protection
DIVISION FOR AIR QUALITY
(Please read instructions before completing this form)

DEP7007B
MANUFACTURING OR PROCESSING OPERATIONS

EMISSION POINT NO. (1)	PROCESS DESCRIPTION (2)	CONTINUOUS OR BATCH (3)	MAXIMUM OPERATING SCHEDULE *(Hours/Day, Days/Week, Weeks/Year)* (4) A	PROCESS EQUIPMENT *(Make, Model, Etc.)* (5)	DATE INSTALLED (6)
CT04 CT05 CT06 CT07 CT08 CT09 CT10 CT11	Electric Generation	C	2500 hrs/yr	ABB GT 11N2 Combustion Turbine or Westinghouse W501D Combustion Turbine	4/94 (1) 4/95 (3) 4/96 (1) 4/97 (1) 4/98 (1) 4/99 (1)

EMISSION POINT NO. (1)	LIST RAW MATERIAL(S) USED (7)	MAXIMUM QUANTITY INPUT OF EACH RAW MATERIAL *(Specify Units/Hour)* (8) A, B	TYPE OF PRODUCTS (9)	QUANTITY OUTPUT *(Specify Units)* MAXIMUM HOURLY (Specify Units) (10a) A	QUANTITY OUTPUT *(Specify Units)* MAXIMUM ANNUAL (Specify Units) (10b) A
CT04-CT11	ABB Water	Approximately 99,000 lb/hr	Electric Energy	137,440 KW	343.6×10^6 KWH
CT04-CT11	West. Water	73,930 lb/hr	Electric Energy	128,380 KW	320.95×10^6 KWH

A. Per CT
B. May vary depending on degree of NOx control required.

SECTION I. SUMMARY SHEET (*Make additional copies, if necessary*)

Emission Point Number	Facility Description(s)	Control Equipment[1] A			Stack Parameters A, B					Control Efficiency %	Capture[3] or Collection Efficiency %	Basis of Estimate
		Type	Date Installed	Cost $ C	Height ft.	Diameter[2] ft.	Temp. °F	Flow ACFM	Exit Velocity ft/sec.			
CT04-11	West.	Water Inj.	4/94	2 Mill.	170'	16.4	950	1.97×10^6	155	--------	------	--------
CT04-11	ABB	Water Inj.	4/94	2 Mill.	170'	16.4	875	2.08×10^6	164	--------	------	--------

1. If a facility has secondary control equipment in addition to primary control equipment, use a separate line and indicate, under type, that it is a secondary control.
2. If the stack is rectangular, specify the dimensions. If there is no stack for a particular point, enter the minimum height of release under 'Height' and write NA (Not Applicable) under 'Diameter'.
3. Capture or collection efficiency is the efficiency with which the pollutants are collected at the emission source before being sent to the control device.

(REVISED 5/87)

A. Per CT B. Stack parameters determined at new base elevation and orientation.

DEP7007N
Continued

EMISSION POINT NO.	NAME AND CHEMICAL COMPOSITION OF POLLUTANTS		GRAIN LOADING (Grains/SCF at 68°F) A		AMOUNT EMITTED A		BASIS OF ESTIMATE (Attach copies of calculations)
			INLET	OUTLET	MAXIMUM Lb/Hr.	MAXIMUM Tons/Yr.	
CT04-11	SO2	West.	NA	0	0	0	Manufacturers data and calculations.
	NOx		NA	0.035	222	250	
	TSP		NA	.0007	4.4	5	
	PM10		NA	.0007	4.4	5	
	CO		NA	0.0117	74	83	
CT04-11	SO2	ABB	NA	0	0	0	
	NOx		NA	0.0355	251	282	
	TSP		NA	0.0014	10	11	
	PM10		NA	0.0014	10	11	
	CO		NA	0.0038	27	30	

A. Per CT

Fuel Usage Rates *

Max Hourly: West = 1325 x 10^6 Btu/HR x MCF/1040 Btu = 1274 x 10^6 CF/HR

ABB = 1463 x 10^6 Btu/HR x MCF/1040 Btu = 1408 x 10^6 CF/HR

Max Annual: West = $1\chi274$ x 10^6 CF/HR x (2500 HR/YR x 0.90) = 2867 BCF/YR

ABB = $1\chi408$ x 10^6 CF/HR x (2500 HR/YR x 0.90) = 3168 BCF/YR

* Based on Natural Gas energy content of 1040 Btu/MCF

Emissions

Grain Loading:

West. $\text{SCFM} = 1.97 \times 10^6 \text{ ACFM } \frac{460+68}{460+949} = 738{,}226 \text{ SCFM}$

NO_x = 222 LB/HR x HR/60 min x min/738,226 SCF x 7000 GR/LB

= 0.035 GR/SCF

TSP & PM10 = 4.4 LB/HR x HR/60 min x min/738,226 SCF x 7000 GR/LB

= 0.0007 GR/SCF

CO = 74 LB/HR x HR/60 min x min/738,220 SCF x 7000 GR/LB

= 0.0117 GR/SCF

ABB $\text{SCFM} = [984\ M^3/S \times 35.31\ ft^3/M^3 \times 60 \text{ sec/min}]\ \frac{460+68}{460+873}$

= 825,748 SCFM

NO_x = 251 LB/HR x HR/60 min x min/825,748 SCF x 7000 GR/LB

= 0.0355 GR/SCF

TSP & PM10 = 10 LB/HR x HR/60 min x min/825,748 SCF x 7000 GR/LB

= 0.0014 GR/SCF

CO = 27 LB/HR

= 0.0038 GR/SCF

IV. Public Notice

Carl H. Bradley
SECRETARY

Wallace G. Wilkinson
GOVERNOR

RECEIVED
OCT 3 8 43 AM '91

COMMONWEALTH OF KENTUCKY
NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION CABINET
DEPARTMENT FOR ENVIRONMENTAL PROTECTION
DIVISION FOR AIR QUALITY
316 St. Clair Mall
Frankfort, Kentucky 40601

102-2740-0001
Cook
Frankfort

September 11, 1991

Harrodsburg Herald
P.O. Box 68
Harrodsburg, Kentucky 40330

Gentleman:

Please publish the enclosed notice as a display advertisement in your newspaper as soon as possible. The advertisement should have a width of two columns, with a corresponding length.

Billing should be mailed to:

Ms. Caryl M. Pfeiffer
Kentucky Utilities Company
One Quality Street
Lexington, Kentucky 40507

RECEIVED
FILE ROOM
OCT 2 2 15 PM '91
DIVISION FOR
AIR QUALITY

Affidavit or proof of publication should be mailed immediately after publication to:

Mr. Roger S. Cook
Natural Resources and Environmental Protection Cabinet
Division for Air Quality
316 St. Clair Mall
Frankfort, Kentucky 40601

The proof of publication shall consist of an affidavit or one (1) full page containing the advertisement. Payment cannot be made until proof of publication of this notice has been received.

Sincerely,

Gerald R. Goebel
for James W. Dills, Manager
Permit Review Branch

JWD/ALW/awj
Enclosure
cc: Roger S. Cook
Bluegrass Regional Office
Ms. Caryl M. Pfeiffer

ard Members

...ttle ...the ...eet- ...& ...resi- ...erry ...resi- ...med ...Vicki ...ficer; ...asur- ...npire ...ns is ...l Ed- ...Wade, ...e. ...eeting ...bruary ...e Mon-

day, Oct. 21 at 7 p.m. at the Court House Annex. The officers and board encourage anyone interested in Mercer County Little League to attend the meeting.

LEGAL NOTICE

CONCERNING THE CONSTRUCTION OF EIGHT COMBUSTION TURBINES AT THE E.W. BROWN STATION LOCATED IN MERCER COUNTY, KENTUCKY

Kentucky Utilities Company has applied to the Division of Air Quality for a permit to construct eight, simple cycle combustion turbines at their existing E.W. Brown Generating Station in Mercer County, Kentucky.

The application will be subject to the New Source Performance Standards (NSPS) and to the Prevention of Significant Deterioration (PSD) of air Quality provisions of the Clean Air Act which requires the use of Best Available Control Technology. The application's proposed use of good combustion control practices for particulate, beryllium, carbon dioxide, and violate organic compounds; 0.3% sulfur content low sulfur fuel oil for sulfur dioxide; and water injection for the control of nitrogen oxides have been analyzed and concluded to be the Best Available Control Technology. Although the ground level concentration of sulfur dioxide is predicted by dispersion modeling to exceed the National Ambient Air Quality Standard, the project may be permitted since the permit will require actions by the applicant to correct the predicted exceedance prior to the startup of the facilities authorized by the permit. Furthermore, since ground level concentrations are predicted to be less than regulatory defined significant concentrations, the project is approvable without the above corrections. Additionally, the predicted consumption of the remaining increments for Prevention of Significant Deterioration of Air Quality has been determined through dispersion modeling and the results are tabulated below:

POLLUTANT	INCREMENT CONSUMPTION (ug/m3)	MAXIMUM INCREMENT AVAILABLE (ug/m3)
SO2		
Annual	1.24	20
24-Hour	12.7	91
3-Hour	59.1	512

AND PERS... Pursuan... to provide (... Burgin, Kent... tucky, does ...

A. An ad... in the corpo... 1991 at a ra... property.

B. For th... accept and u... Kentucky, pr... istrator and t... ments.

C. The B... mail bills for t... lished, and ta... full on or bef... fore Novemb... the bill as a ... 1992, shall h... Any tax rema... of ten percen...

All tax b... there-after be... cil. All tax bil... regular busin...

A. There... and intangibl... raising reven... Burgin, Kent...

B. The t... per $100 of ...

C. For th... accept and u... ble and inta... County Prop... II shall be b...

D. Tax ... collected by... cles are reli... tucky Revis...

E. Tax ... shall be col... Hall in Bur... manner as ...

JANE BIRD HUTTON
Publisher

Established 1884
606-734-2726

The Harrodsburg Herald

INCORPORATED

HARRODSBURG, KENTUCKY 40330

NOTARIZED PROOF OF PUBLICATION

STATE OF KENTUCKY

COUNTY OF MERCER ss

Before me, a Notary Public, in and for said County and State, this 1st day of October, 19 91, came, Bill Randolph, personally known to me, who being duly sworn, states as follows: That he is General Manager of ***The Harrodsburg Herald, Inc.,*** Harrodsburg, Kentucky, and that said publication of date of Sept. 26, 1991 (Date) carried the advertising of Division of Air Quality, concerning a Notice of Public, occupying the following space: 23 inches

Bill Randolph
(Signature)

Grace M. Moore
(Notary Public)

My Commission Expires: [illegible] Expires June 26, 19[illegible]

V. Preliminary Determination

ATTACHMENT D

Technical Support Document (TSD) Table 2-3 “BACT Results”

TABLE 2-3

PROPOSED EMMISSION LIMITS AND CONTROL TECHNOLOGIES FOR THE PROPOSED TURBINES

POLLUTANT	NSPS (ppm)	PROPOSED EMMISSION LIMIT (ppm)	RECOMMENDED CONTROL TECHNOLOGY
Firing Natural Gas			
NOx	75	42	Water Injection
CO	--	--	Good Combustion Control
VOC	--	--	Good Combustion Control
PM	--	--	Good Combustion Control
SO_2	--	--	Good Combustion Control
Firing Distillate Fuel Oil			
NO_x	75	65	Water Injection
CO	--	--	Good Combustion Practices
VOC	--	--	Good Combustion Practices
PM	--	--	Good Combustion Practices
SO_2	150	0.3% Sulfur	Hourly Limit of 2,500 hours/year and 0.3% Sulfur Fuel

NSPS = New Source Performance Standard

[d:\...\job\11927005\kent0429.t23]

APPENDIX E

Technical Support Document

PSD Permit Application

For a Proposed Modification of the E. W. Brown Generating Station

for Kentucky Utilities Company

June 12, 1991

TECHNICAL SUPPORT DOCUMENT
PSD PERMIT APPLICATION
FOR A
PROPOSED MODIFICATION OF THE
E. W. BROWN GENERATING STATION

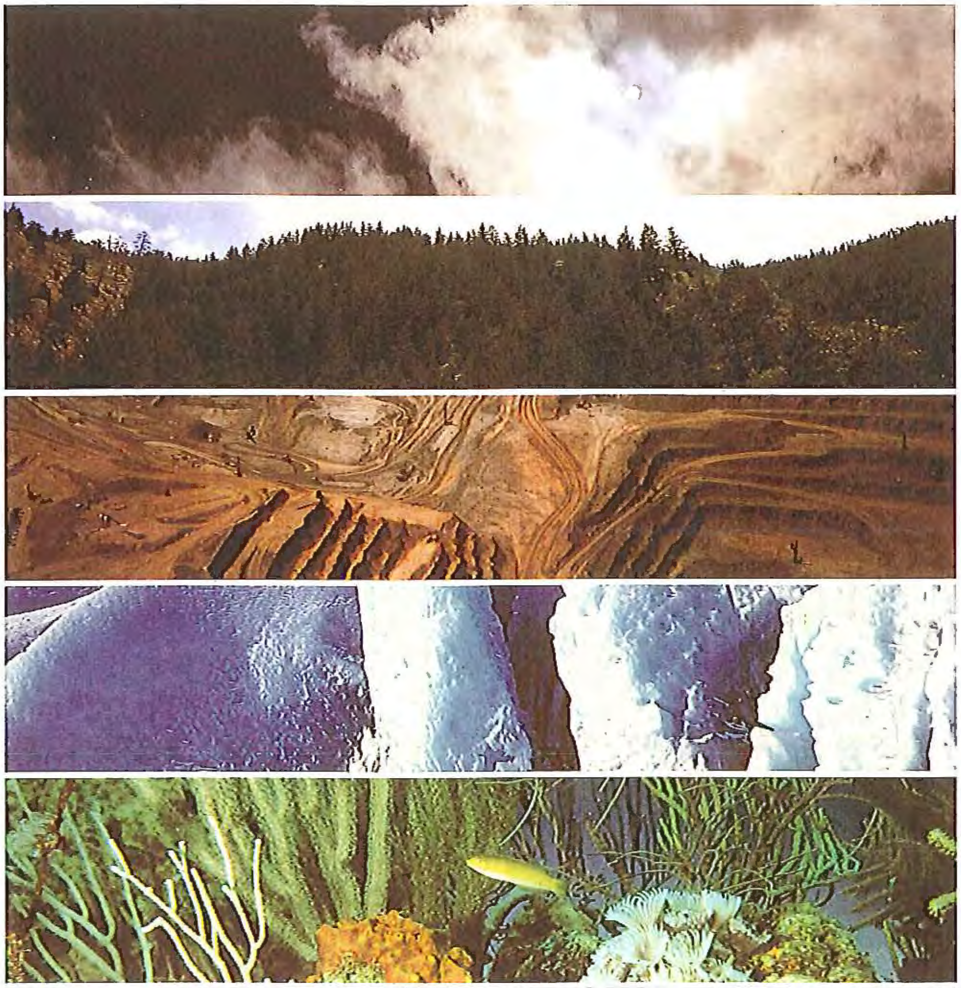
FOR

KENTUCKY UTILITIES COMPANY

DAMES & MOORE

D&M Job No. 11927-005-07
June 12, 1991

[d:\...\job\11927005\kent0429.haw]



DAMES & MOORE

TECHNICAL SUPPORT DOCUMENT
PSD PERMIT APPLICATION
FOR A
PROPOSED MODIFICATION OF THE
E. W. BROWN GENERATING STATION

FOR
KENTUCKY UTILITIES COMPANY

Submitted By
Kentucky Utilities Company

Prepared By
Dames & Moore
1550 Northwest Highway
Park Ridge, Illinois 60068

D&M Job No. 11927-005-07
June 12, 1991

[d:\...\job\11927005\kent0429.haw]

TABLE OF CONTENTS

TABLE OF CONTENTS - Continued

APPENDICES

LIST OF TABLES

LIST OF TABLES - Continued

LIST OF TABLES - Continued

LIST OF FIGURES

EXECUTIVE SUMMARY

Kentucky Utilities Company (KU) is proposing to modify its E. W. Brown Generating Station, located in Mercer County, Kentucky. The modification consists of adding up to eight 75 to 100 megawatt, simple cycle, combustion turbines. The turbines will have the potential to combust natural gas and distillate oil and will be used as peaking duty units. The primary fuel for these units will be No. 2 fuel oil as natural gas is not currently available at the site. The nearest bulk gas supply is over 10 miles from the site. This source of natural gas would only be available under an interruptible contract agreement with a 12 to 24 hour notification required before draw-down. The first unit is scheduled to be in operation by the summer of 1994. The proposed project is a major modification of an existing source and is subject to the Prevention of Significant Deterioration (PSD) regulations. Based on the net pollutant emission increases associated with the proposed modification, KU is subject to PSD review for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), particulate matter smaller than 10 microns (PM_{10}), total suspended particulate (TSP), carbon monoxide (CO), and volatile organic compounds (VOCs).

A BACT analysis following the USEPA's Top-Down approach was performed to address air pollution from the proposed combustion turbines. BACT was determined on a pollutant by pollutant basis for SO_2, NO_2, TSP/PM_{10}, CO and VOCs. For NO_x emissions, BACT was determined to be water injection with an associated NO_x emission limitation of 65 ppm. For emissions of TSP/PM_{10}, CO and VOCs, BACT was determined to be good combustion control while operating close to full load. For SO_2 emissions, BACT was determined to be firing with No. 2 distillate fuel oil with a sulfur content not to exceed 0.3 percent, and an hourly usage limitation of 2,500 hours/year.

Dispersion modeling analyses were performed for the proposed modification using worst-case emissions and operating parameters provided by three vendors. These analyses indicate that emissions of NO_x, TSP/PM_{10}, and CO will result in an insignificant impact for each of the five years in the meteorological data base. As a result, an assessment of compliance with PSD increments and National Ambient Air Quality Standards (NAAQS) for these pollutants was not required. Because emissions of SO_2 resulted in a significant impact, compliance with PSD increments and NAAQS were required.

With respect to consumption of the allowable PSD increments, the proposed modification (the only SO_2 PSD increment-consuming source in the area) was modeled for the 5-year data base. The predicted maximum annual average; highest 24-hour average; and highest, second-highest 3-hour average SO_2 concentrations of 1.24, 12.7, and 44.2 $\mu g/m^3$, respectively, are well below the corresponding PSD increments of 20, 91, 512 $\mu g/m^3$. There are no PSD Class I areas within 100 kilometers of the E. W. Brown Station site.

Dispersion modeling analyses were performed to demonstrate compliance with the NAAQS for SO_2. The maximum annual average SO_2 concentration of 59.9 $\mu g/m^3$ complies with the NAAQS of 80 $\mu g/m^3$. Modeled exceedances of the 3-hour and 24-hour average SO_2 NAAQS occurred and the predominant contribution to these exceedances were the existing coal-fired boilers at the E. W. Brown Station. The proposed turbines have an insignificant impact for all of the receptor/periods of the predicted exceedances.

Kentucky Utilities will resolve the predicted SO_2 exceedances due to the E. W. Brown Station prior to the operation of the turbines. Potential control strategies include:

- Refine the dispersion modeling analyses of the E. W. Brown Station including (1) verification of exhaust parameters and (2) allowance for the recognition of wind direction dependent building dimensions for sources having stack height to building height ratios less than 1.5;

- Increase stack height up to GEP;

- Revise SIP limitations or some combination of the above.

With respect to the ambient air quality monitoring requirements of PSD review, the maximum predicted concentrations of TSP/PM_{10}, SO_2, NO_2, and CO due to the proposed modification are below the monitoring de minimis concentrations, thus exempting KU from this requirement. KU is also exempt from monitoring for O_3 because of using representative O_3 data collected at a site in Fayette County.

In summary, the proposed modification complies with the requirements of PSD review.

Respectfully submitted,

DAMES & MOORE
A Professional Limited Partnership

John A. Foster for HAW
Herbert A. Weidemann
Associate

John A. Foster
John A. Foster
Project Atmospheric Scientist

HAW/JAF:lc

[d:\...\job\11927005\kent0429.haw]

1.0 INTRODUCTION

Kentucky Utilities Company is proposing to modify its E. W. Brown Generating Station, located in Mercer County, Kentucky. The modification consists of adding up to eight 75 to 100 megawatt simple cycle combustion turbines. The turbines will have the potential to combust natural gas and distillate oil. The first unit is scheduled to be in operation by the summer of 1994; the next three by the summer of 1995, and one in each of the following three years (1996, 1997, and 1998). These are peaking units that will be limited to an operating schedule of 2,500 hours per year. This report constitutes an application for a Prevention of Significant Deterioration (PSD) air permit to construct the proposed turbines.

1.1 REGULATORY REQUIREMENTS

The proposed project is a major modification of an existing source and is subject to Prevention of Significant Deterioration (PSD) regulations. Based on the net pollutant emission increases associated with the proposed modification, Kentucky Utilities Company is subject to PSD review for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), particulate matter smaller than 10 microns (PM_{10}), total suspended particulate (TSP), carbon monoxide (CO), and volatile organic compounds (VOCs). In addition, the proposed turbines will meet the requirements specified in the New Source Performance Standards.

1.1.1 Prevention of Significant Deterioration

The PSD regulations, amended by the U.S. Environmental Protection Agency (USEPA) on August 7, 1980 (45 FR 52675), specify that any major new stationary source or major modification to an existing source within an air quality attainment area must undergo a PSD review prior to commencement of construction. For new sources, the regulations apply to:

1. Any source type in any of 28 designated industrial source categories having potential emissions of 100 tons per year or more; and

2. Any other source having potential emissions of 250 tons per year or more of any pollutant regulated under the Clean Air Act.

"Potential emissions" are defined as the emissions of any pollutant at maximum design capacity (or less than maximum design capacity if specified as a permit condition) including the control efficiency of air pollution control equipment. PSD review generally consists of:

1. A case-by-case Best Available Control Technology (BACT) demonstration, taking into account energy, environmental, and economic impacts as well as technical feasibility;

2. An ambient air quality impact analysis to determine whether the allowable emissions from the proposed source, in conjunction with all other applicable

emission increases or reductions, would cause or contribute to a violation of the applicable PSD increments and NAAQS (refer to Table 1-1);

3. An assessment of the direct and indirect effects of the proposed source on general growth, soil, vegetation, and visibility; and

4. Public comment, including an opportunity for a public hearing.

In addition to the above requirements, preconstruction ambient air quality monitoring for up to a 1-year period may be required for each pollutant subject to PSD review. An applicant may be exempt from this requirement, however, if there are existing air quality monitoring data representative of the station site, or if the impact from the proposed facility is less than the monitoring de minimis concentrations listed in Table 1-1.

1.1.2 New Source Performance Standards

The proposed turbines will be subject to the New Source Performance Standards (NSPS), Subpart GG - "Standard of Performance for Stationary Gas Turbines." The NSPS stipulates that electric utility stationary gas turbines with a heat input at peak load greater than 10.7 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the standards for NO_x and SO_2. With respect to NO_x, the NSPS requires that no owner or operator of a stationary gas turbine with a heat input rate greater than 100 MMBtu/hour shall emit any gases which contain nitrogen in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = Allowable NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

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

F = NO_x emission allowance for fuel-bound nitrogen.

For SO_2 emissions, the NSPS requires that no owner or operator of a stationary gas turbine shall discharge in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis. In addition, no owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

TABLE 1-1

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS), PSD INCREMENTS, SIGNIFICANT EMISSION RATES, SIGNIFICANT IMPACT CONCENTRATIONS, AND DE MINIMIS CONCENTRATIONS

		NAAQS ($\mu g/m^3$)		PSD INCREMENTS ($\mu g/m^3$) CLASS			SIGNIFICANT EMISSION RATES	SIGNIFICANT IMPACT CONCENTRATIONS	DE MINIMIS CONCENTRATIONS
POLLUTANT	AVERAGING PERIOD	PRIMARY	SECONDARY	I	II	III	(tons/year)	($\mu g/m^3$)	($\mu g/m^3$)
Total Suspended Particulate Matter (TSP)	Annual	--	--	5[a]	19[a]	37[a]	25	1	--
	24-Hour	--	--	10[a,b]	37[a,b]	75[a,b]		5	10
Particulate Matter less than 10 μm (PM_{10})	Annual	50	--	--	--	--	15	1	--
	24-Hour	150	--	--	--	--		5	10
Sulfur Dioxide	Annual	80	--	2	20	40	40	1	--
	24-Hour	365[b]	--	5[b]	91[b]	182[b]		5	13
	3-Hour	--	1300[b]	25[b]	512[b]	700[b]		25	--
Nitrogen Dioxide	Annual	100	c	2.5	25	50	40	1	14
Ozone	1-Hour	235[d]	c	--	--	--	40[e]	--	f
Carbon Monoxide	8-Hour	10,000[b]	c	--	--	--	100	500	575
	1-Hour	40,000[b]	c	--	--	--		2000	--
Lead	Calendar Quarter	1.5	c	--	--	--	0.6	--	0.1
Total Reduced Sulfur (TRS), Reduced Sulfur Compounds	1-Hour	--	--	--	--	--	10	--	10
Asbestos	--	--	--	--	--	--	0.007	--	--
Mercury	24-Hour	--	--	--	--	--	0.1	--	0.25
Beryllium	24-Hour	--	--	--	--	--	0.0004	--	0.001
Fluorides	24-Hour	--	--	--	--	--	3	--	0.25

TABLE 1-1 (continued)

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS), PSD INCREMENTS, SIGNIFICANT EMISSION RATES, SIGNIFICANT IMPACT INCREMENTS, AND DEMINIMIS CONCENTRATIONS

(CONTINUED)

POLLUTANT	AVERAGING PERIOD	NAAQS ($\mu g/m^3$) PRIMARY	SECONDARY	PSD INCREMENTS ($\mu g/m^3$) CLASS I	II	III	SIGNIFICANT EMISSION RATES (tons/year)	SIGNIFICANT IMPACT CONCENTRATIONS ($\mu g/m^3$)	DE MINIMIS CONCENTRATIONS ($\mu g/m^3$)
Vinyl Chloride	24-Hour	--	--	--	--	--	1	--	15
Sulfuric Acid Mist	--	--	--	--	--	--	7	--	--
Hydrogen Sulfide	1-Hour	--	--	--	--	--	10	--	0.2

[a]TSP increment to be replaced by PM_{10} increment.

[b]Concentration not to be exceeded more than once per year.

[c]Same as primary NAAQS.

[d]Expected number of days per year on which one or more hourly ozone concentrations exceed this value must be less than 1.

[e]Emissions of volatile organic compounds.

[f]Increase in volatile organic compound emissions of more than 100 tons/year.

1.2 SCOPE OF STUDY

Section 2.0 presents a general description of the proposed emission sources, applicable stack height regulations, and Best Available Control Technology demonstrations. A characterization of the study area in terms of wind flow pattern, rural/urban land use description, topography, and current air quality status is presented in Section 3.0. Model description and data requirements for the air quality impact assessment are presented in Section 4.0 and the model results are provided in Section 5.0. Section 6.0 presents analyses of the impact of the proposed turbines on growth, soil and vegetation, and visibility and an assessment of Kentucky's toxic air pollutant regulations.

2.0 DESCRIPTION OF THE PROPOSED STATION MODIFICATION

2.1 DESCRIPTION OF PROPOSED EMISSION SOURCES

Kentucky Utilities Company's E. W. Brown Generating Station is located in Mercer County, as illustrated in Figure 2-1. Kentucky Utilities proposes to install up to eight simple cycle combustion turbines to this station. A detailed layout of the turbine facility and an artist's rendering of the proposed facility are included in Appendix A. Each turbine will have a rating of between 75 and 100 MW and have the capability to combust natural gas and distillate oil with a sulfur content of 0.3% Three combustion turbine vendors were evaluated. A summary of the pollutant emissions, based on a worst-case scenario, are presented in Table 2-1. These emission rates assume that the turbines operate for 2,500 hours per year. Independent of the selected vendor, the proposed project will be subject to PSD review for SO_2, NO_x, TSP/PM_{10}, CO, and VOC.

2.2 APPLICATION OF STACK HEIGHT REGULATION

The stack height regulations promulgated by USEPA on July 8, 1985 (50 FR 27892) established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. These regulations apply to facilities which commenced construction after December 31, 1970, and to dispersion techniques implemented after that date. The proposed regulations specify that Good Engineering Practice (GEP) stack height is the maximum creditable stack height which a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5\, l_b$$

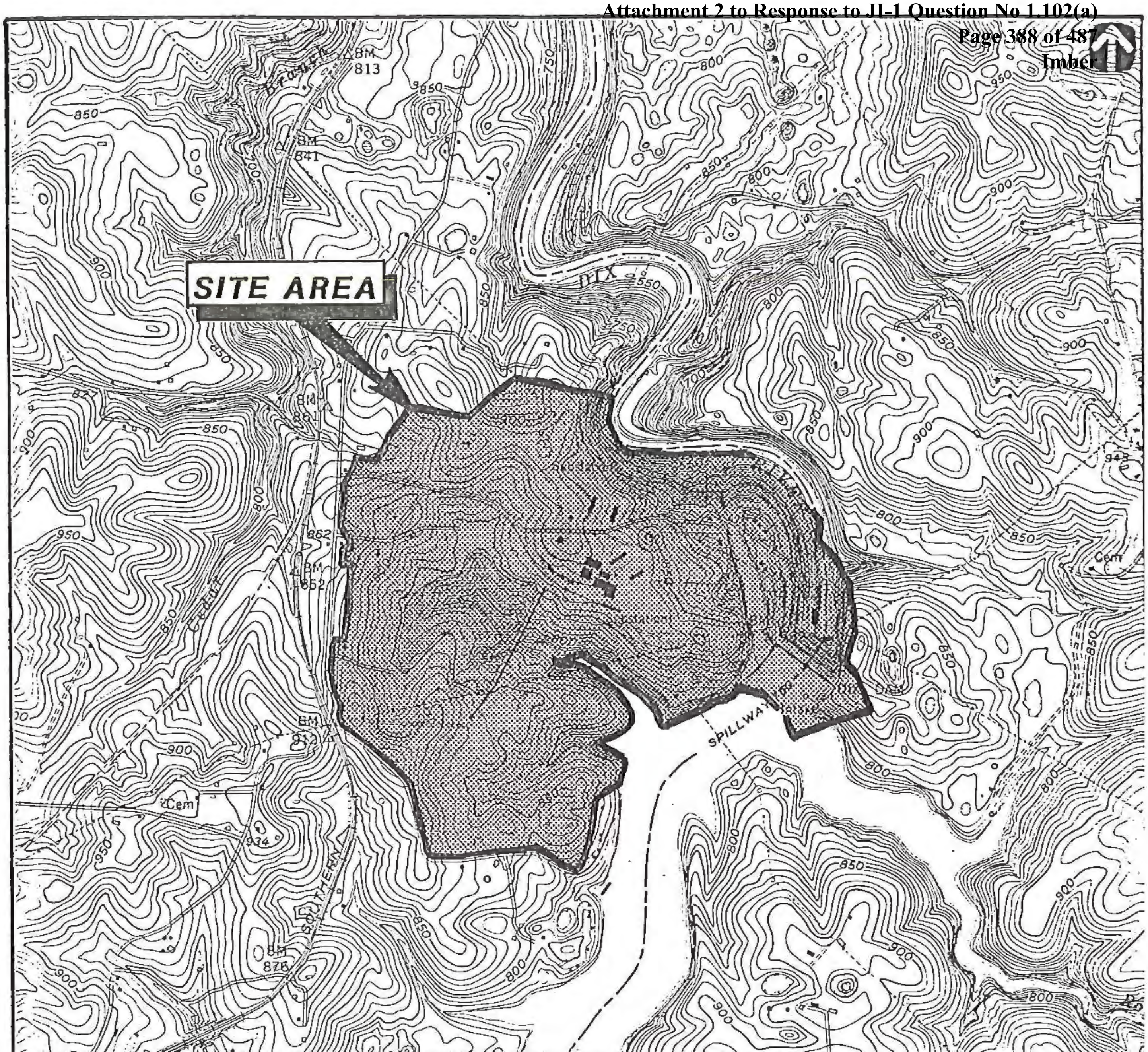
where:

H_g = GEP stack height,

H = Height of the structure on which the source is located, or nearby structure, and

l_b = Lesser dimension (height or width) of the structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on the source is limited to 5 times the lesser dimension (height or width) of that structure or within 0.5 mile (0.8 km) of the proposed stack, whichever is less. The methods for determining GEP stack height for various building configurations have been described in USEPA's technical support document (USEPA, 1985a).



SCALE 1:24 000

1	1/2	0	1 MILE

1000	0	1000	2000	3000	4000	5000	6000	7000 FEET

1	.5	0	1 KILOMETER

MAP REFERENCE:
PORTION OF U.S.G.S QUARDRANGLE MAP
7 1/2 MINUTE SERIES (TOPOGRAPHIC)
WILMORE, KENTUCKY 1952
PHOTOREVISED 1979

FIGURE 2-1
LOCATION OF THE
E.W. BROWN GENERATING STATION

Dames & Moore

TABLE 2-1

SUMMARY OF MAXIMUM POTENTIAL EMISSIONS FROM TURBINES

POLLUTANT	MAXIMUM POTENTIAL EMISSIONS (TONS/YR)*			SIGNIFICANT EMISSION RATE (TONS/YR)
	VENDOR 1 (7 Turbines)	VENDOR 2 (8 Turbines)	VENDOR 3 (7 Turbines)	
SO_2	2743.1	4200.0	3163.1	40
NO_x	2380.0	2420.0	2485.0	40
TSP	131.3	668.0	367.5	25
PM_{10}	131.3	668.0	367.5	15
CO	498.8	750.0	271.3	100
VOC	87.5	204.0	70.0	40

*Based on the highest emissions over the range provided by the vendors, and assumes 2,500 hrs/year operation.

[d:\...\job\11927005\ku0429.t1]

If vendor 1 or 3 is subsequently chosen, the stack heights will be of GEP height, but less than 65 m tall. If vendor 2 is selected, the stacks will be less than GEP height. Units 1 and 2 of the E. W. Brown Station have a stack height less than GEP, while Unit 3 is GEP.

2.3 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) DEMONSTRATIONS

As previously discussed, Kentucky Utilities' proposed combustion turbines are subject to the PSD regulations, which mandate that a case-by-case Best Available Control Technology (BACT) analysis be performed. The installation is subject to PSD review for SO_2, TSP/PM_{10}, NO_x, CO, and VOCs.

The combustion turbines are designed as peaking, simple cycle units. It is anticipated that the turbines will be operated less than 2,500 hours per year during peak electrical conditions within KU's system. The turbine exhaust temperature from the simple cycle turbine units will be approximately 950°F. This high temperature, normal to simple cycle turbine units, will need to be cooled before any post combustion control technologies can be attached. These operating conditions and specifications of the simple cycle turbine units were considered to be a major influence during the process of considering control technologies for these generating units.

The BACT demonstration is based on the assumption that up to 8 combustion turbine units of 75 to 100 MW capacity (nominal ratings) will be installed at the E. W. Brown Generating Station. Since the proposed facility will consist of several identical turbines, this BACT analysis was based on the worst case emissions generated by a turbine, operating at maximum conditions.

2.3.1 Definition and Applicability

The Clean Air Act defines BACT as "...an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant." The BACT proposed must achieve emissions which are at least as stringent as the applicable federally-approved State Implementation Plan (SIP) emission requirements or the federal New Source Performance Standards (NSPS) emission requirements, whichever are more stringent.

The sources of information on control alternatives varies for the different cases being considered. The following categories may be considered in preparing the BACT analysis:

1) BACT/LAER Clearinghouse (USEPA, 1985b, 1990);

2) EPA/State/Local Air Quality Permits;

3) Federal/State/Local Permit Engineers;

4) Control Technology Vendors; and

5) Inspection/Performance Test Reports.

The impact analysis of the BACT review focuses on environmental, energy, and economic impacts of the various levels of source control. The net environmental impact associated with the control alternative should be reviewed. The dispersion modeling normally considers a "worst-case" scenario, thus it constitutes an assessment of the maximum environmental air quality impacts. The energy impact analysis estimates the direct energy impacts of each control option, assessed in terms of total and incremental (units of energy per ton of reduction) energy costs. The economic impact of a control option is assessed in terms of cost-effectiveness and ultimately whether the option is economically reasonable. Normally the economic impacts are reviewed on a cost per ton of pollutant removed basis.

Currently, the USEPA is recommending a "top-down" approach in conducting a BACT analysis. In this approach, progressively less stringent levels are analyzed until a level of control considered BACT is reached based upon the environmental, energy, and economic impacts. This BACT analysis for the proposed combustion turbines utilizes this top-down approach.

Several sources were consulted regarding recent stationary combustion turbine installations and the associated BACT implemented. These sources included the BACT/LAER Clearinghouse, recent permit applications, USEPA air permitting authorities, and the proposed vendors. The results of the BACT/LAER Clearinghouse review are presented in Table 2-2. The proposed emission source limits and pollution control technologies for the turbines are presented in Table 2-3.

2.3.2 Emissions of Sulfur Dioxide (SO_2)

Sulfur dioxide (SO_2) emissions from stationary combustion turbines are directly proportional to the sulfur content of the fuel burned. Nearly 100 percent of the sulfur in the fuel is converted to SO_2 during combustion.

Two possible strategies have been identified for the reduction of SO_2 emissions from stationary combustion turbines: flue gas desulfurization (FGD) and the firing of low sulfur fuels. Due to the high volume of flue gas generated by these turbines, the cost of FGD to control emissions from stationary combustion turbines is considered unreasonable. Nonetheless, in keeping with USEPA's top-down requirements for the performance of BACT analysis, the following FGD alternatives were evaluated:

TABLE 2-3

PROPOSED EMMISSION LIMITS AND CONTROL TECHNOLOGIES FOR THE PROPOSED TURBINES

POLLUTANT	NSPS (ppm)	PROPOSED EMMISSION LIMIT (ppm)	RECOMMENDED CONTROL TECHNOLOGY
Firing Natural Gas			
NOx	75	42	Water Injection
CO	--	--	Good Combustion Control
VOC	--	--	Good Combustion Control
PM	--	--	Good Combustion Control
SO_2	--	--	Good Combustion Control
Firing Distillate Fuel Oil			
NO_x	75	65	Water Injection
CO	--	--	Good Combustion Practices
VOC	--	--	Good Combustion Practices
PM	--	--	Good Combustion Practices
SO_2	150	0.3% Sulfur	Hourly Limit of 2,500 hours/year and 0.3% Sulfur Fuel

NSPS = New Source Performance Standard

[d:\...\job\11927005\kent0429.t23]

- Wet scrubbing with slaked lime or limestone
- Dry scrubbing with slaked lime
- Dry scrubbing with sodium bicarbonate

2.3.2.1 Control of SO_2 Emissions Using Flue Gas Desulfurization

Techniques commonly used by the electric power industry to control emissions of sulfur dioxide from coal-fired electric power generating equipment include wet scrubbers and dry scrubbers. To the best of our knowledge, none of these control technologies have ever been applied to oil-fired units or to peak load or "peaking" combustion turbines. However, each of these technologies will be discussed for potential application to the proposed turbines. At the time this analysis was performed, turbines from several manufacturers were being evaluated by Kentucky Utilities for the proposed installation. This analysis of the above mentioned control alternatives is based upon their potential application to a turbine operating in such a manner as to produce the worst-case emissions.

2.3.2.1.a Wet Scrubbers

Wet scrubbing is based on the use of an alkaline solution, contacted to a maximum extent with the hot flue gas. For the removal of SO_2, the flue gas is scrubbed with a 5 to 15% solution of lime (CaO) or dissolved limestone ($CaCO_3$). The SO_2 reacts with the solution to form calcium sulfite and sulfate salts. The liquor is continuously recycled to the scrubbing tower after the addition of fresh lime or limestone, and the removal of excess calcium sulfite/sulfate salts. In addition to calcium-based absorbents, numerous other absorbents are available for use including sodium and ammonia-based solutions.

Throwaway lime/limestone/alkali flyash scrubber systems can be represented by the flow diagram shown in Figure 2-2. The reagent used is added to the reaction tank or scrubber basin along with water to make a slurry and is further mixed with recycled slurry from the scrubber. The slurry, typically comprised of water and an absorbent of either calcium carbonate or slaked lime, is then returned to the scrubber. Within this recycle loop, the reaction tank is used to control slurry flows and a thickener or pond is used to remove solids. The slurry may be purged with oxygen to oxidize the calcium sulfite solids to calcium sulfate thus producing a more easily dewatered solid waste. The thickened solids are then ready for disposal.

There are various potential problems associated with the use of wet scrubbers. The scrubber would have to be located down-stream of a particulate control device for subsequent transfer of the exhaust gas to the scrubber inlet because of the extremely corrosive nature of the exhaust gas exiting the scrubber. The large volume of exhaust gas produced by a simple cycle combustion turbine would require unusually large scrubber towers relative to the MW rating of the unit; i.e., the scrubber modules for a 75 to 100 MW simple-cycle combustion turbine would equal the size of those required for a 500 MW base-load coal-fired generating unit. In addition, the high temperature of the flue gas would necessitate quenching the exhaust gas prior to scrubbing. This quenching process would require enormous quantities of water to reduce the exhaust temperature by at least 500°F. These factors would substantially increase the capital cost of the wet scrubber. Wet scrubbers also require the handling, treatment, and disposal of large quantities of a sludge by-product. In essence, air emissions would be exchanged for water effluents and wastes. Treatment of wet scrubber waste requires dewatering and landfill facilities, which require extensive staffing, operator training, and frequent maintenance. Review of the BACT/LAER Clearinghouse revealed no peaking turbines utilizing wet scrubbers to control SO_2 emissions.

For these reasons, a wet scrubber was not considered further in the BACT analysis. An alternative to wet scrubbing is a process known as dry scrubbing, or spray-dryer absorption.

2.3.2.1.b Dry Scrubbers

A simplified flow diagram for a dry scrubber is shown in Figure 2-3. For application to the proposed turbines, no preheating of the flue gas would be required.

The equipment used for atomizing the reagent stream in the spray dryer can be a rotary atomizer or atomizer nozzles. The slurry solution is atomized into fine droplets in a spray dryer vessel. These droplets impact with the SO_2 molecules and their subsequent absorption leads to the formation of sulfites and sulfates within the droplets. The droplets are generated at a predetermined size such that the sensible heat of the flue gas evaporates the moisture from the resultant salt solution, leaving a dry powder, the majority being entrained in the flue gas exiting the spray dryer. The flue gas leaving the spray dryer contains a mixture of the reacted products and fly ash. Typically, control of these pollutants is accomplished with a baghouse, employing teflon-coated fiberglass bags or by electrostatic precipitators. After particulate removal, the clean gas, with or without reheat, is discharged through the stack. The dry solids from the particulate control device are then sent to waste disposal. If desired, a portion of the solids can be recycled as part of the sorbent feed to increase utilization and, in the case of alkaline flyash, to reduce the quantity of reagent required.

Since the flue gas exhaust temperature is considerably higher than what the teflon-coated bags can withstand the exhaust gas must be quenched to cool the gases to an acceptable baghouse inlet temperature. Again this quenching process would require enormous quantities of water.

Historically, dry scrubbers have only been employed on coal-fired installations. Review of the BACT/LAER Clearinghouse revealed no turbines utilizing dry scrubbers for the control of SO_2. Due to the impacts of treating large volumetric flow rates at high temperatures of the exhaust from the proposed turbines, dry scrubbing was not selected as BACT.

2.3.2.2 Control of SO_2 Emissions Using Low Sulfur Fuel

Unlike FGD, the use of reduced sulfur fuel is considered reasonable (both economically and technologically) for stationary combustion turbines. A review of the BACT/LAER Clearinghouse revealed that for all listings, SO_2 emission limits for fuel oil fired turbines are stipulated, as a percent sulfur in the fuel oil specifications, with an hourly usage limit.

TABLE 2-2

BACT/LAER REVIEW FOR OIL-FIRED GAS TURBINES

TURBINE SIZE (MMBTU/hr)	DATE PERMIT ISSUED	STATE	EMISSION LIMITS (lb/hr)					CONTROL TECHNOLOGY
			PM	SO_2	NO_x	CO	VOC	
1875	4/15/89	VA	19	572	490	140	17	PM, Equipment Design; SO_2, 0.3% Sulfur; NO_x, Steam Injection CO, Equipment Design
1308	9/7/89	VA	12.5	0.2*	65[1]	28.6	6.3	SO_2, 02.% Sulfur; NO_x, 0.05% N_2
1163.5	12/12/89	VA	-	38.3[1]	11.7[1]	-	-	NO_x, SCR SO_2, Low Sulfur Fuel Oil
1060	9/6/89	NC	0.0094*	218	227	23	10.1	NO_x, Water Injection SO_x, Low Sulfur Fuel Oil
1029	7/1/88	VA	28	216	259	25.5	6.6	SO_2, Low Sulfur Fuel
887	7/8/87	CA	-	Fuel Spec.	9[1]	-	-	SO_2, (0.05% S); NO_x H_2O Injection and SCR
739	10/23/89	CT	0.035*	60[1]	62[1]	0.109*		PM, Good Combustion Techniques, SO_2, Low Sulfur Fuel Oil, NO_x, Steam Injection
555	9/29/89	CT	0.035*	51[1]	62[1]	0.109*		SO_2, 0.28% Sulfur Fuel; NO_x, Steam Injection
509	9/6/89	NC	0.033*	105	134	10.9	4.7	NO_x, Water Injection SO_2, Low Sulfur Fuel Oil

* lb/MMBTU
[1] ppmv

TABLE 2-2 (Continued)

BACT/LAER REVIEW FOR OIL-FIRED GAS TURBINES

TURBINE SIZE (MMBTU/hr)	DATE PERMIT ISSUED	STATE	EMISSION LIMITS (lb/hr)					CONTROL TECHNOLOGY
			PM	SO_2	NO_x	CO	VOC	
500	1/29/90	NY	0.063*	Fuel Spec.	65[1]	-	5	NO_x, Water Injection SO_2, Low Sulfur Fuel Oil (0.3%)
499.9	8/8/88	CT	0.025*	35[1]	40[1]	-	-	NO_x, Water Injection SO_2, Low Sulfur Fuel Oil
490	1/12/89	CA	0.0357*	0.051*	0.15*	-	-	Fuel oil Usage Limited to 11 Hours/Day
430	3/6/89	NY	0.08*	Fuel Spec.	65[1]	0.026*	-	NO_x Water Injection SO_2, Low Sulfur Fuel Oil
416	5/2/89	NY	0.024*	Fuel Spec.	65[1]	0.024*	-	NO_x, Steam Injection SO_2, 0.25% Sulfur Fuel Oil
310	5/11/88	PA	-	-	42[1]	-	-	NO_x, Steam Injection
245	6/21/88	MI	-	0.25*	42[1]	0.35*	-	SO_2, 0.25% Sulfur Fuel NO_x, Water Injection CO, Water Injection
80 MW	11/21/89	NY	0.014*	Fuel Spec.	42[1]	25[1]	7[1]	NO_x, Steam Injection SO_2, Low Sulfur Fuel Oil (0.2%)
80 MW	3/18/87	AK	-	Fuel Spec.	75[1]	-	-	SO_2, (0.06%) NO_x, H_2O Injection
75 MW	1/27/88	CA	-	-	140	94	-	NO_x, Water Injection

* lb/MMBTU
1 ppmv

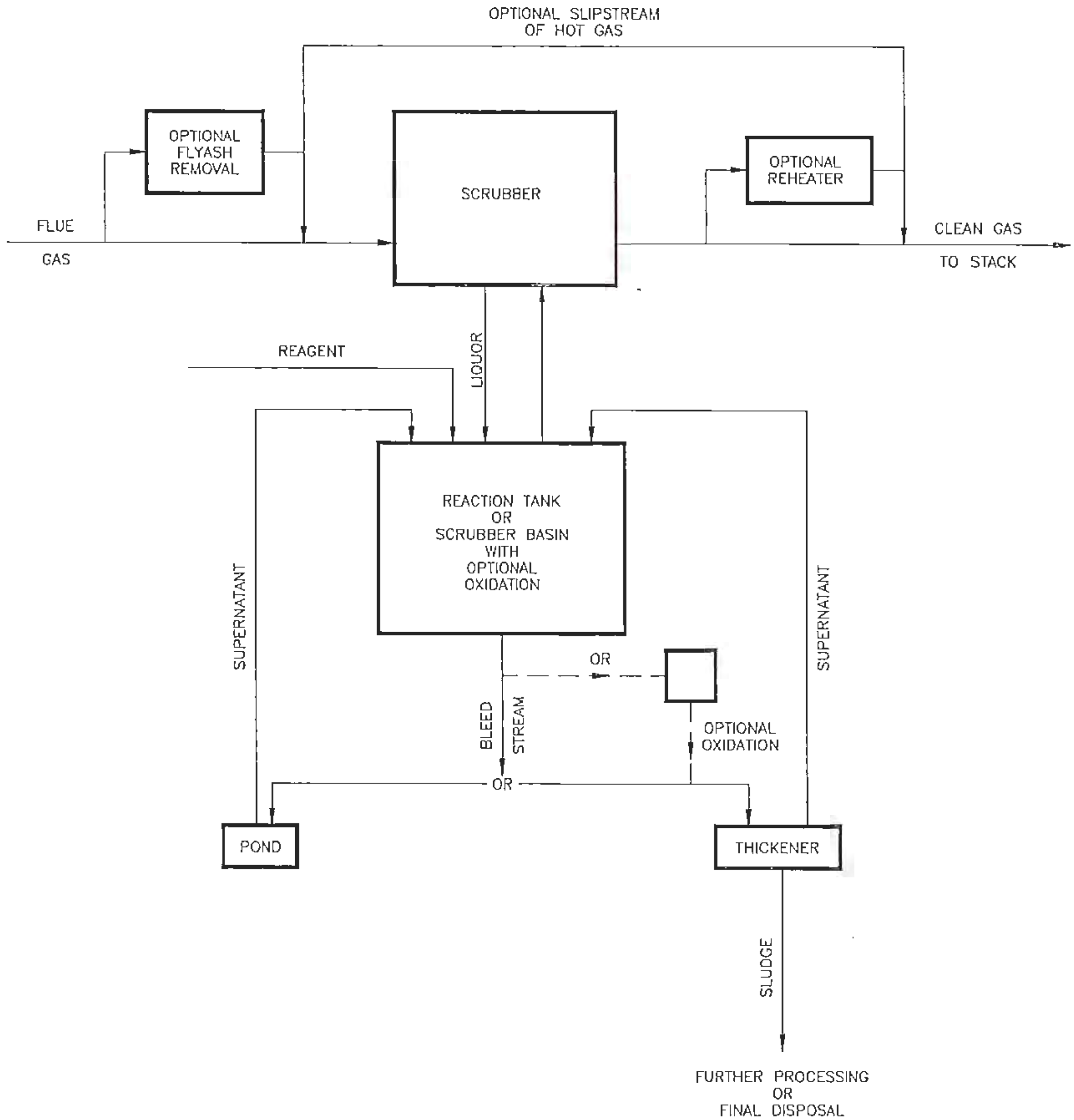
TABLE 2-2 (Continued)

BACT/LAER REVIEW FOR OIL-FIRED GAS TURBINES

TURBINE SIZE (MMBTU/hr)	DATE PERMIT ISSUED	STATE	EMISSION LIMITS (lb/hr)					CONTROL TECHNOLOGY
			PM	SO_2	NO_x	CO	VOC	
71.9	8/19/87	CT	0.036*	63[1]	62[1]	0.29*	-	SO_2, Low Sulfur Fuel NO_x, Water Injection
50 MW	3/10/88	NY	-	Fuel Spec.	75[1]	-	-	SO_2, (0.37% S); NO_x, H_2O Injection
40 MW	6/3/87	NJ	-	Fuel Spec.	9.6[1]	-	-	SO_2, (0.15% S); NO_x, H_2O Injection and SCR
40 MW	2/7/89	NY	0.033*	Fuel Spec.	65[1]	0.022*	-	NO_x, Water Injection SO_2, Low Sulfur Fuel Oil
35 MW	9/1/88	FL	-	Fuel Spec.	65	10[1]	7[1]	NO_x, Steam Injection SO_2, Low Sulfur Fuel Oil
18 MW	6/29/89	HI	-	110	34.8	-	-	NO_x, Water Injection SO_2, 0.5% Sulfur Fuel Oil

* lb/MMBTU
1 ppmv

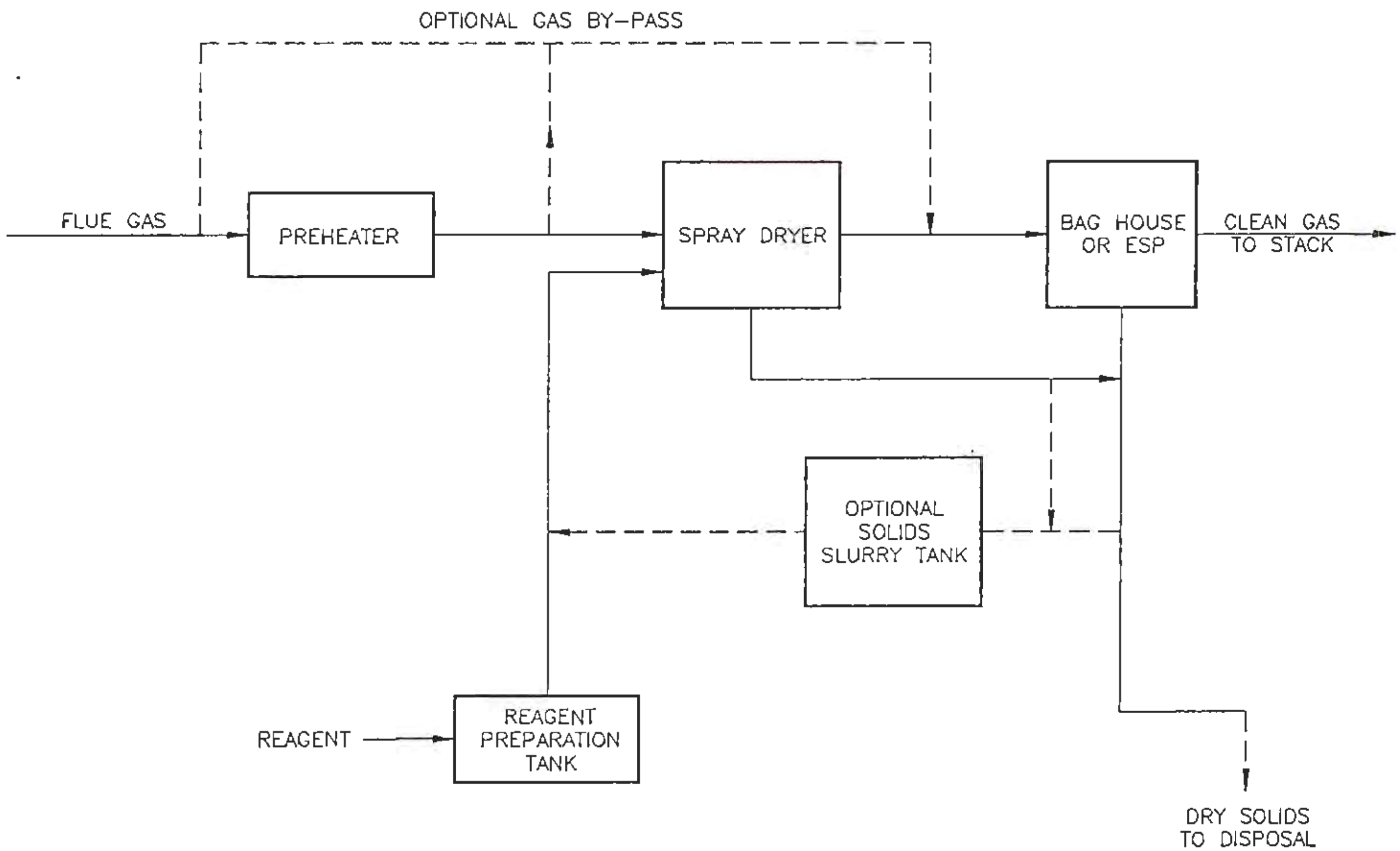
[d:\...\job\11927005\kent0429.t23]



KENTUCKY UTILITIES
MERCER COUNTY, KENTUCKY

FIGURE 2-2
TYPICAL LIME/LIMESTONE
SCRUBBER FLOW SCHEME

DWG NO.: 11927005.F100 | DAMES & MOORE



KENTUCKY UTILITIES
MERCER COUNTY, KENTUCKY

FIGURE 2-3
TYPCIAL SPRAY DRYER
FGD FLOW DIAGRAM

DWG NO.: 11927005.F102 | DAMES & MOORE

TABLE 2-4

SUMMARY OF TOP-DOWN BACT ANALYSIS FOR CONTROL

OF SO2 EMISSIONS FROM THE PROPOSED TURBINE

Control Alternative	Emissions (lb/hr	(tpy)	Emissions Reduction(a) (tpy)	Total Annualized Cost(b) ($/yr)	Economic Impacts: Total Cost Effectiveness(c) ($/ton)	Incremental Cost Effectiveness(d) ($/ton)	Environmental Impacts: Toxics Impact(e) (Yes/No)	Adverse Environmental Impacts(f) (Yes/No)	Energy Impacts: Increase Over Baseline(g) (MMBtu/yr)
No. 2 fuel oil (0.20% sulfur)	280	1226	3066	$11,477,456	$3,743	$9,983	No	No	None
No. 2 fuel oil (0.30% sulfur)	420	1840	2453	$5,356,146	$2,184	$2,184	No	No	None
No. 2 fuel oil (0.7% sulfur)	980	4292	NA	NA	NA	NA	No	No	None

(a) Emissions reduction over baseline level
(b) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using 17.49% over 20 years (not including inflation) is used to express capital costs in present-day annual costs.
(c) Cost effectiveness is the total annualized cost for the control option divided by the emmissions reductions resulting from the option.
(d) The incremental cost effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emmisions reduction resulting from the respective alternatives.
(e) Toxics impact means there is a toxic impact consideration for the control alternative.
(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative.
(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.

NA = Not Applicable

Several grades of distillate fuel oil, with reduced sulfur content are available within the region of the Brown Station. For our analysis, No. 2 oil containing sulfur levels of 0.2 percent, 0.3 percent and 0.7 percent were evaluated. As may be seen in Table 2-4, based on 2500 hours of operation, the firing of oil containing 0.2 percent sulfur would reduce SO_2 emissions 613 tons below the reduction attained by the firing of 0.3 percent sulfur oil. The economic analysis shows that it would cost KU an additional \$6,121,310 annually (based on vendor-supplied cost estimates for these fuel oils), resulting in an excessive incremental cost of \$9,983/ton.

2.3.2.3 Determination of BACT for SO_2 Emissions

Table 2-4 presents a top-down summary of the alternatives evaluated for the control of SO_2 emissions. Control of SO_2 emissions requires the combustion of a low sulfur fuel rather than the application of FGD. BACT for the control of SO_2 from the turbines is proposed as fuel oil which does not exceed a sulfur content of 0.3 percent and a limit of 2,500 hours/year for the firing of fuel oil. The proposed turbines will also have the capability to burn natural gas, which is considered a clean fuel; with the emissions of SO_2 from combustion being negligible. Natural gas is not currently available at the site. The nearest bulk gas supply is over 10 miles from the site. This source of natural gas would only be available under an interruptible contract agreement with a 12 to 24 hour notification required before draw-down.

2.3.3 Emissions of Oxides of Nitrogen (NO_x)

Emissions of oxides of nitrogen, often referred to by the general formula NO_x, result from a combination of nitrogen sources; both nitrogen in the fuel and in the combustion air contribute to the formation of NO_x. NO_x formation rates are a function of both thermodynamic and kinetic considerations. When firing natural gas or fuel oil, nearly all NO_x emissions result from the formation of thermal NO_x. Thermodynamically speaking, higher combustion temperatures favor the formation of NO_x and should therefore be minimized. Within the combustion zone, temperatures are controlled to a large extent by the air-fuel ratio; thus optimal control of the air-fuel ratio is paramount to controlling NO_x formation.

Many post-combustion NO_x control techniques (i.e., ammonia injection, flue gas recycle) are not applicable to combustion turbines due to the lack of both appropriate temperature zones and residence times. The two techniques that were evaluated for application to the proposed turbines are selective catalytic reduction (SCR) and water injection. Again, this analysis is based on worst-case emissions and operating parameters of a turbine unit under consideration.

2.3.3.1 Control of NO_x Emissions Using Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) employs catalysts to promote the reduction of NO_x emissions (primarily NO and NO_2) with ammonia (NH_3) and oxygen (O_2). The basic chemical reactions in this process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$$

In SCR, ammonia is added to an exhaust stream and reacted NO_x in the SCR catalyst to produce nitrogen and water.

In recent years, several SCR systems have been installed on combined cycle combustion turbines. Typically, SCR is not applicable to simple cycle turbines due to the high temperatures of the flue gas ($\geq$950°F), and no such applications were found in the review of the BACT/LAER Clearinghouse. In addition to the high exhaust temperatures, operating difficulties and catalyst fouling have been experienced with units firing oil and to our knowledge no units are now continuously operating successfully on oil in the United States. Most regulatory agencies currently consider SCR to be "not demonstrated on oil" for simple cycle turbines. A typical SCR system is shown in Figure 2-4. Due to the unproven nature of SCR for these turbines, SCR was not selected as BACT.

SCR is not considered BACT for the proposed turbine for the following reasons:

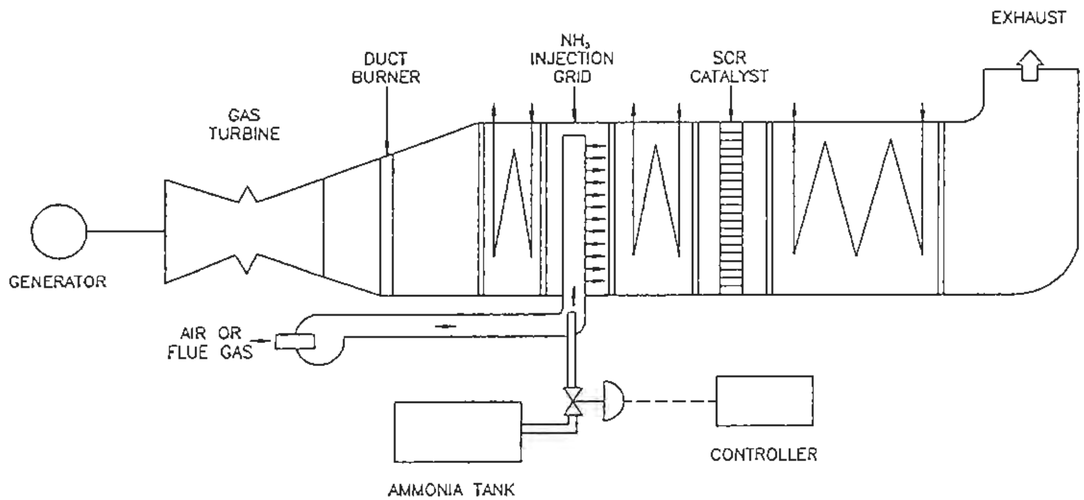
<u>Technically Infeasible</u>

- If ammonia is injected into a gas stream at over 650°C, NO will form. If this high temperature condition exists, then the ammonia must be injected immediately in front of the catalyst. This requires a distribution baffle to ensure proper mixing and would introduce a substantial back pressure on the turbine. This back pressure will result in power losses for the turbine. This condition will have economic ramifications.

- If the exhaust gas temperature varies during operation, as a result of changes in load, or a change in supplemental firing, the turbine operating temperature could move outside of the effective operating range of the catalyst. Some costly and complicated techniques have been attempted to overcome this problem and would have economic cost implications on any installation.

- Ammonium bisulfate formation and resultant fouling occur at fuel sulfur levels above 0.05 percent, while the primary fuel for the proposed turbine contains 0.3 percent sulfur.

- SCR is not a proven technology for simple cycle turbines. One simple cycle gas turbine (1 MW pilot facility) demonstrating a high temperature catalyst is currently being tested with an applicable SCR. The turbine started operation in February of 1991 and no catalyst aging data is available to date.



KENTUCKY UTILITIES
MERCER COUNTY, KENTUCKY

FIGURE 2-4
SCR CATALYTIC SYSTEM

DWG NO.: 11927005.F101 | DAMES & MOORE

Energy

- SCR energy penalty due to the 6 inch H_2O pressure drop would increase the heat rate by 1 percent and decrease the electrical output by about 6 MW per unit.

Environmental

- No significant difference in environmental impacts due to the decrease in NO_x emission rates.

- Secondary SCR environmental impacts such as emissions of nitrosoamines can be potentially significant. In addition, at high temperatures ammonia can quickly be oxidized to form NO_x if injection rates are not maintained precisely.

- The control of ammonia must be very precise to ensure that adequate ammonia is available for reaction with the catalyst and conversely to prevent excessive ammonia passing through the catalyst, slip, and being emitted into the atmosphere. The solution for maintaining the desired control efficiency is to maintain a concentration of approximately 10 ppm of ammonia in the turbine exhaust.

- Handling of large quantities of a hazardous toxic compound such as ammonia presents a potential risk to human health and the environment.

- The spent catalyst is not recyclable and becomes a hazardous waste.

2.3.3.2 Control of NO_x Emissions Using Water Injection

The injection of water or steam to control NO_x emissions is so widely accepted that injection design is incorporated into essentially every turbine manufactured today.

Even though wet injection results in increased maintenance, inspection requirements, combustor wear, and water treatment requirements, it still remains desirable as a proven and effective method of controlling NO_x emissions. Water injection costs were determined for the reduction of emissions to both 65 ppm and 42 ppm NO_x. The costs associated with water injection to reduce NOx for the proposed turbines are detailed in Table 2-5.

The total annual capital and O & M costs for water injection to reduce NO_x to 42 ppm were determined to be $688,366, with a resultant cost per ton of NO_x removed of $460. To reduce NO_x emissions to the 65 ppm level, a total annual cost of $592,396 was determined, with a resultant cost per ton of NO_x removed to be $445.

TABLE 2-5

ESTIMATED CAPITAL AND OPERATING COSTS FOR
WATER PURIFICATION (SINGLE TURBINE)

CAPITAL COSTS		
DIRECT CAPITAL COSTS (DC)		
Purchased Equipment Costs (PE)		
Anthracite filter beds	$190,000	$190,000
Water storage tank (500,000 gallon)	$59,000	$59,000
Freight (5% of equipment, OAQPS Manual)	$12,450	$12,450
PE Total	$261,450	$261,450
Direct Installation Costs (DI)		
Foundations and supports (8% of PE, OAQPS Manual)	$20,916	$20,916
Handling and erection (14% of PE, OAQPS Manual)	$36,603	$36,603
DI Total	$57,519	$57,519
DC Total	$318,969	$318,969
INDIRECT CAPITAL COSTS (IC)		
Engineering (10% of PE, OAQPS Manual)	$26,145	$26,145
Construction and field expenses (5 % of PE, OAQPS Manual)	$13,073	$13,073
Contractor fees (10% of PE, OAQPS Manual)	$26,145	$26,145
Over-all contingencies (20% of PE, engineering estimate)	$52,290	$52,290
IC Total	$117,653	$117,653
DC + IC Total	$436,622	$436,622
Construction loan - 10% for 1 year	$43,662	$43,662
TOTAL CAPITAL INVESTMENT (TCI)	$480,284	$480,284
Annualize at 17.49% over 20 years	$87,484	$87,484
OPERATION AND MAINTENANCE (O & M)		
DIRECT ANNUAL COSTS (DA)		
Operating and maintenance	$24,286	$24,286
Deionized water (contract supply)	$542,814	$446,844
DA Total	$567,100	$471,130
INDIRECT ANNUAL COSTS (IA)		
Overhead (60% of maintenance parts & labor costs, OAQPS)	$14,571	$14,571
Administrative charges (2% of TCI, OAQPS Manual)	$9,606	$9,606
Property tax (1% of TCI, OAQPS Manual)	$4,803	$4,803
Insurance (1% of TCI, OAQPS Manual)	$4,803	$4,803
IA Total	$33,783	$33,783
O & M Total	$600,882	$504,912
TOTAL ANNUAL CAPITAL AND O & M COSTS	$688,366	$592,396
Annual NOx Emissions (tons):	303	468
Annual NOx Removed (tons):	1498	1332
Cost per ton of NOx removed:	$460	$445

2.3.3.3 Determination of BACT for NO_x Emissions

Table 2-6 presents a comparison of the NO_x control technologies evaluated. Due to its proven effectiveness, reliability, and reasonable economic cost, water injection was selected as BACT for the proposed turbines. Control of NO_x emissions to 65 ppm is proposed since the predicted ground-level concentrations of NO_x from the proposed turbines are below the significant impact level concentrations.

2.3.4 Emissions of CO and VOCs

Emissions of CO and VOCs (in the form of uncombusted hydrocarbons) from stationary combustion turbines operating at full load are relatively low because of efficient combustion of the fuel. The higher the percent of full load at which a turbine operates, the lower the emissions of VOCs and CO. Combustion turbines normally operate at 80 to 100 percent of full load with VOCs emissions averaging less than 30 ppmv and CO emissions averaging less than 100 ppmv at 15 percent O_2. The proposed combustion turbines will be operated as efficiently as possible to conserve fuel which will at the same time reduce VOCs and CO emissions; therefore, VOC and CO emissions from stationary combustion turbines are not selected for control by pollution equipment but rather, are controlled by combustion efficiency.

2.3.4.1 Control of CO and VOCs Emissions Using Catalytic Oxidation

To our knowledge, no turbines fired exclusively by fuel oil are equipped with an oxidation catalyst due to the likelihood of catalyst fouling by sulfur and poisoning by other contaminants. In addition, this catalyst will oxidize the SO_2 in the exhaust gas to sulfur trioxide which readily combines with water to produce sulfuric acid mist.

Since this technology has not been demonstrated on fuel oil fired combustion turbines, catalytic oxidation was not selected as BACT for emissions of CO and VOCs from the proposed turbines.

2.3.4.2 Determination of BACT for CO and VOCs Emissions

Due to the high exhaust temperature characteristics of simple-cycle combustion turbines, emissions of CO and VOCs are expected to be below the average for all turbines as a group.

BACT for emissions of CO and VOCs from the proposed turbines is considered efficient combustion, while operating as close to full load as possible.

2.3.5 Emissions of Particulate Matter (PM)

The worst case PM emissions from any turbine being considered are equal to 66.8 lbs PM/hour (while operating at the highest oil-fired rate). At present, there exist three accepted

TABLE 2-6

SUMMARY OF TOP-DOWN BACT ANALYSIS FOR CONTROL

OF NOx EMISSIONS FROM THE PROPOSED TURBINE

					Economic Impacts		Environmental Impacts		Energy Impacts
Control Alternative	Emissions (lb/hr	Emissions (tpy)	Emissions Reduction(a) (tpy)	Total Annualized Cost(b) ($/yr)	Total Cost Effectiveness(c) ($/ton)	Incremental Cost Effectiveness(d) ($/ton)	Toxics Impact(e) (Yes/No)	Adverse Environmental Impacts(f) (Yes/No)	Increase Over Baseline(g) (MMBtu/yr)
Water Injection (NOx at 42 ppm)	242	303	1498	$688,365	$460	$579	No	No	None
Water Injection (NOx at ~~42~~ 65 ppm)	375	468	1332	$592,396	$445	$445	No	No	None
Dry Operation	1440	1801	NA	NA	NA	NA	No	No	None

(a) Emissions reduction over baseline level
(b) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using 17.49% over 20 years (not including inflation) is used to express capital costs in present-day annual costs.
(c) Cost effectiveness is the total annualized cost for the control option divided by the emmissions reductions resulting from the option.
(d) The incremental cost effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emmisions reduction resulting from the respective alternatives.
(e) Toxics impact means there is a toxic impact consideration for the control alternative.
(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative.
(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.

NA = Not Applicable

add-on control methods for the control of particulate matter. These methods include wet scrubbers, baghouses, and electrostatic precipitators.

As per discussion and published emission factors (USEPA, 1985c), electrostatic precipitators or baghouses are preferred over wet scrubbers for two reasons. First, the efficiency of particulate matter collection is generally higher for electrostatic precipitators and baghouses. Second, the percentage of the total TSP classified as PM_{10} is greater from wet scrubbers than from electrostatic precipitators and baghouses. As a result, wet scrubbers were not considered further as a potential control device for particulate matter.

A baghouse provides an efficient control system for TSP and PM_{10} in many applications. However, due to the normal exit temperature from the combustion turbine of 786°C (955°F), the exhaust gas must be cooled to prevent the bag collectors from burning or melting. Therefore, an additional process unit must be installed and operated to control the baghouse inlet temperature.

The use of an ESP would allow the hot turbine exit gas to flow with minimal cooling, in the inlet of the ESP without any additional devices. However, because of the low TSP loading and the high gas flow rate, the use of an ESP would prove to be ineffective for TSP control of the combustion turbine exhaust.

2.3.5.1 Control of PM Emissions with a Baghouse

As previously stated, the hot combustion turbine exhaust gas must be cooled to approximately 300-400°F to protect the bag fabric, thus requiring enormous quantities of water to quench the exhaust gas. The proposed combustion turbine generating station is designed for use as a peaking facility and not a base load station. Therefore, the use of a boiler as a heat sink is not applicable. The use of a cogenerating station would superimpose an undesirable lag time factor for startup and shutdown (since boilers must be started up and shut down in a controlled manner). The slow startup/shutdown is required to prevent excessive differentials in expansion/constriction stresses. Therefore, a water spray chamber for quenching exhaust gas would have to be installed between the turbine exhaust and the baghouse inlet.

2.3.5.2 Determination of BACT for Emissions of Particulate Matter (PM)

Emissions of particulate matter from distillate oil and natural gas fired stationary combustion turbines are minimal. Due to the technical infeasibilities discussed previously, an add on control device was not selected as BACT for the proposed turbines. BACT for the control of PM emissions is proposed as good combustion control.

3.0 SITE AREA CHARACTERISTICS

Site area characteristics related to air quality impact of the proposed modification include wind flow, rural/urban land use classification, topography, and air quality status.

3.1 WIND FLOW PATTERN

Measurements of surface wind flow data from the National Weather Service (NWS) station at the Lexington Airport (located approximately 30 kilometers north-northeast of the E. W. Brown Generating Station) were considered as representative of the local meteorology at the station. Annual wind roses for each year from 1983 through 1987 are presented in Figures 3-1 through 3-5, respectively. Figure 3-6 presents the cumulative annual wind rose based on the 5-year period. The prevailing wind direction is from the south, occurring 16 percent of the time.

3.2 RURAL/URBAN LAND USE DESCRIPTION

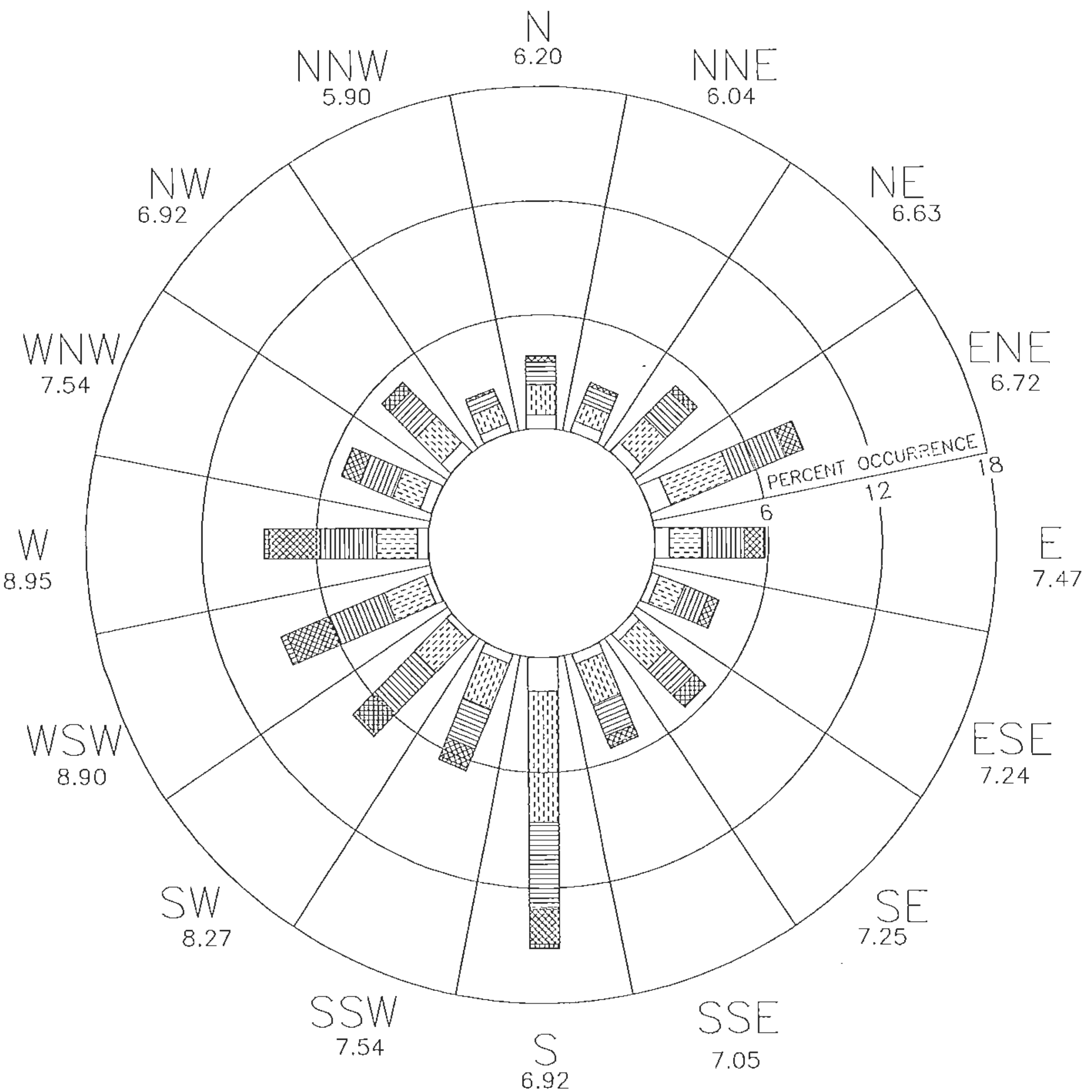
An analysis technique was developed by Irwin (1979) to classify a site area as either rural or urban for purposes of using rural or urban dispersion coefficients. The classification can be based on either average heat flux, land use, or population density within a 3-kilometer radius from a plant site. Of these, the USEPA has specified that land use is the most definitive criterion (USEPA, 1986). The rural/urban classification based on land use is as follows:

> Using the meteorological land use typing scheme (Table 3-1) established by Auer (1978), an urban classification of the site area requires more than 50 percent of the following land use types: heavy industrial (I1), light-moderate industrial (I2), commercial (C1), single-family compact residential (R2), and multi-family compact residential (R3). Otherwise, the site area is considered rural.

Figure 2-1 presents the area within a 3-kilometer radius around the station site. Using the land use typing scheme, rural land use types comprise greater than 95 percent of the total area. Thus, the site and surrounding area are classified as rural, allowing the use of rural dispersion coefficients in the air quality modeling analyses.

3.3 TOPOGRAPHY

The grade elevation of the proposed station is approximately 920 feet above mean sea level (MSL). Terrain elevations rise to a peak elevation of approximately 1,010 feet MSL within 3 kilometers of the station. Since terrain elevation exceeds the stack top elevation, terrain may be an important factor in plume transport and dispersion. As a consequence, terrain elevations were considered in the dispersion modeling analyses.



NUMBERS INDICATE SECTOR MEAN WIND SPEED

WIND SPEED RANGE

0–3 KNOTS
4–6
7–10
11–16
17–21
>21

FIGURE 3–1
WIND FREQUENCY DISTRIBUTION
ANNUAL WIND ROSE FOR 1983

HOURLY SURFACE WIND OBSERVATIONS
BLUEGRASS FIELD
LEXINGTON, KENTUCKY

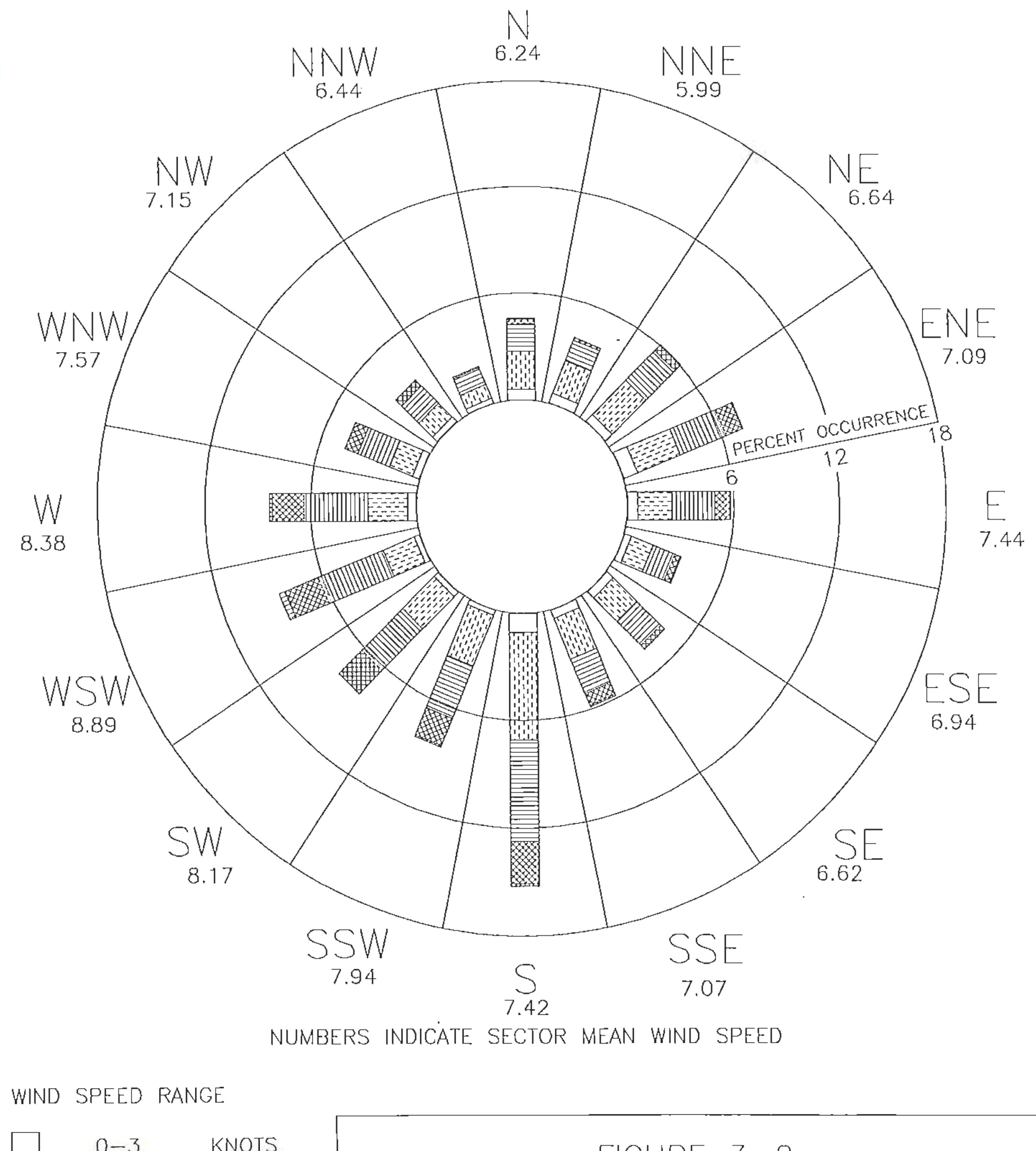


FIGURE 3–2
WIND FREQUENCY DISTRIBUTION
ANNUAL WIND ROSE FOR 1984

HOURLY SURFACE WIND OBSERVATIONS
BLUEGRASS FIELD
LEXINGTON, KENTUCKY

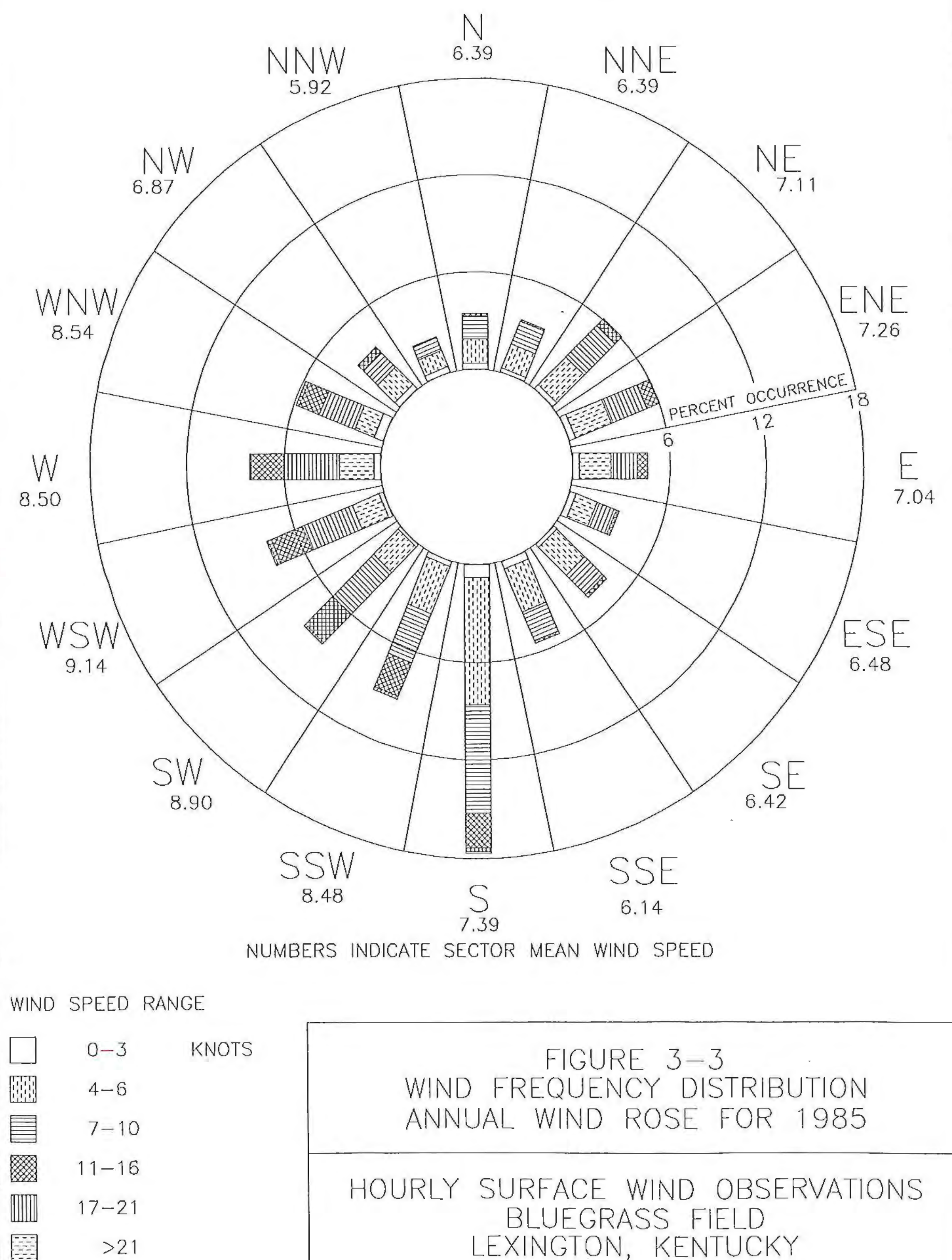


FIGURE 3–3
WIND FREQUENCY DISTRIBUTION
ANNUAL WIND ROSE FOR 1985

HOURLY SURFACE WIND OBSERVATIONS
BLUEGRASS FIELD
LEXINGTON, KENTUCKY

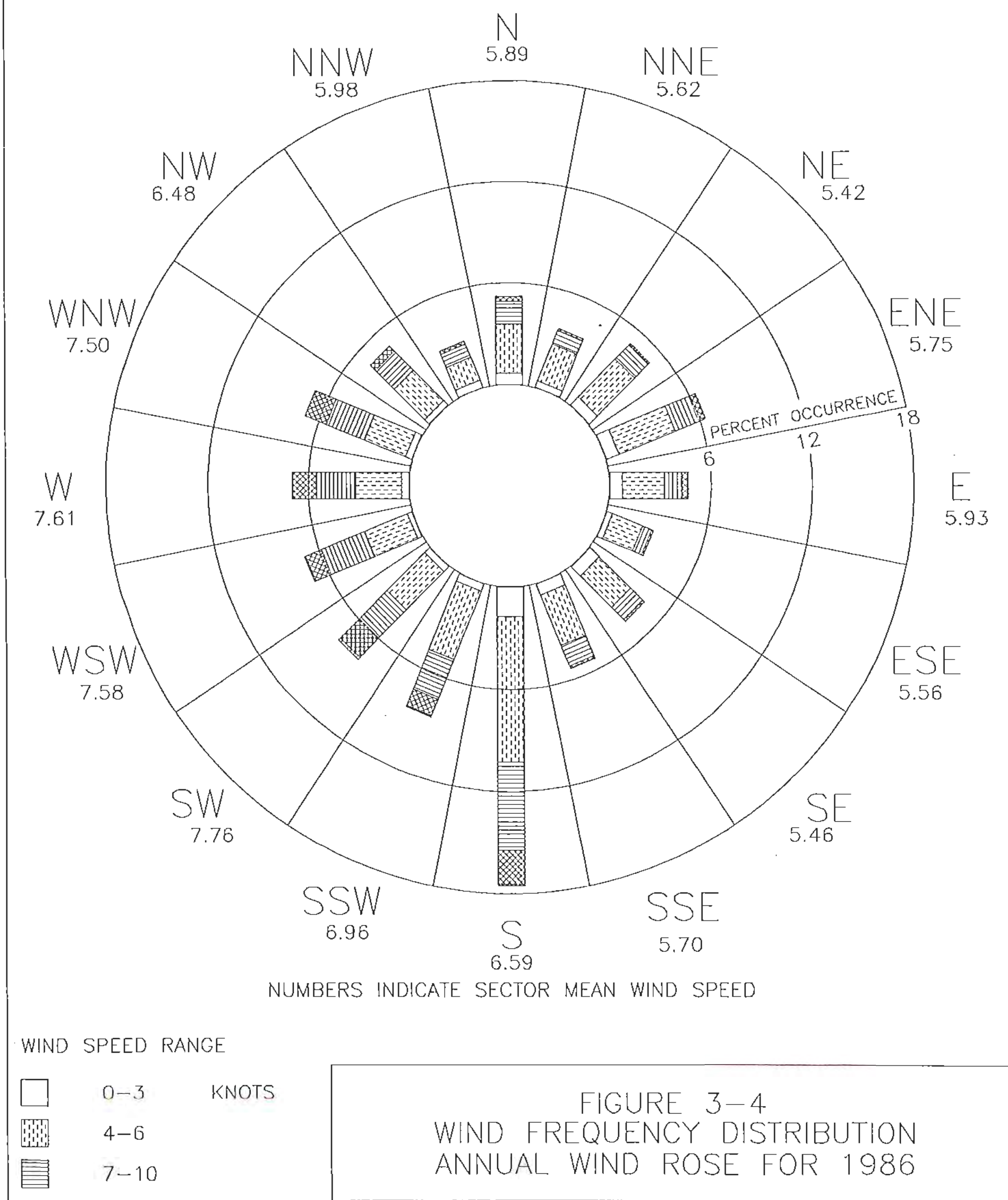


FIGURE 3-4
WIND FREQUENCY DISTRIBUTION
ANNUAL WIND ROSE FOR 1986

HOURLY SURFACE WIND OBSERVATIONS
BLUEGRASS FIELD
LEXINGTON, KENTUCKY

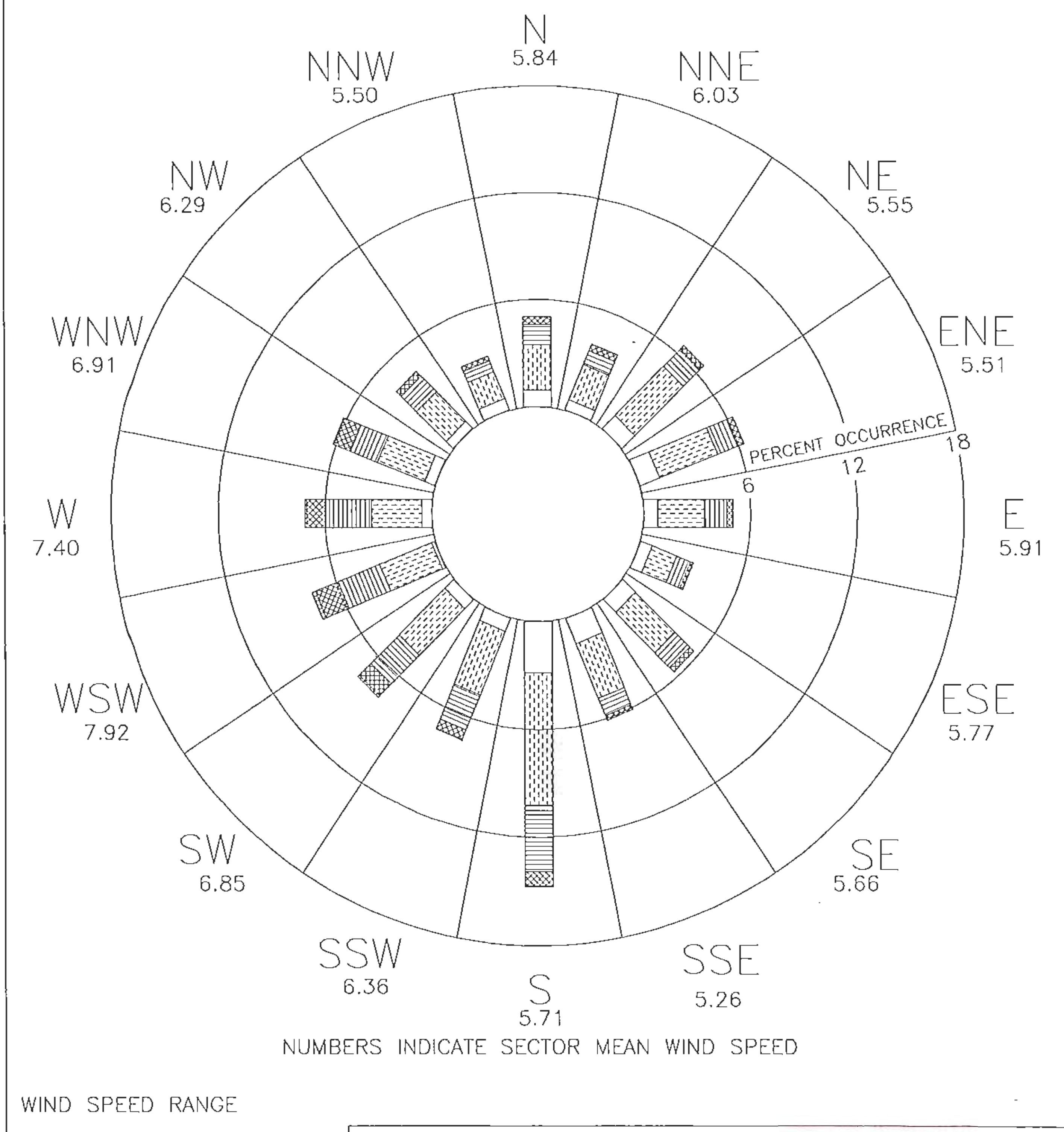
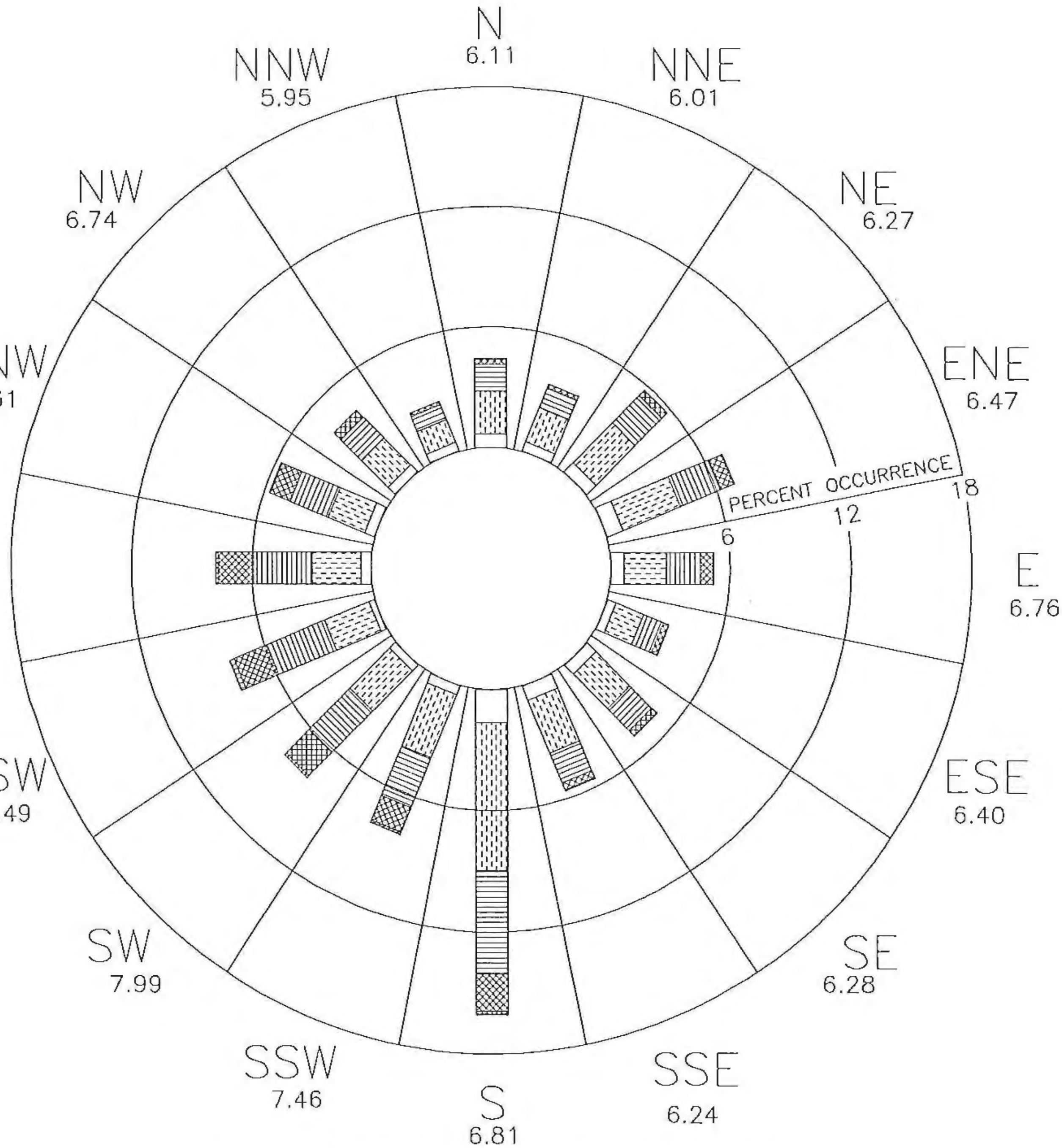


FIGURE 3–5
WIND FREQUENCY DISTRUBUTION
ANNUAL WIND ROSE FOR 1987

HOURLY SURFACE WIND OBERVATIONS
BLUEGRASS FIELD
LEXINGTON, KENTUCKY



NUMBERS INDICATE SECTOR MEAN WIND SPEED

WIND SPEED RANGE

0–3 KNOTS
4–6
7–10
11–16
17–21
>21

FIGURE 3–6
WIND FREQUENCY DISTRIBUTION
COMBINED ANNUAL WIND ROSE (1983–1987)

HOURLY SURFACE WIND OBSERVATIONS
BLUEGRASS FIELD
LEXINGTON, KENTUCKY

TABLE 3-1

IDENTIFICATION AND CLASSIFICATION OF LAND USE TYPES

TYPE	USE AND STRUCTURES	VEGETATION
I1	**Heavy Industrial** Major chemical, steel and fabrication industries; generally 3-5 story buildings, flat roofs	Grass and tree growth extremely rare; <5% vegetation
I2	**Light-Moderate Industrial** Railyards, truck depots, warehouses, industrial parks, minor fabrications; generally 1-3 story buildings, flat roofs	Very limited grass, trees almost totally absent; <5% vegetation
C1	**Commercial** Office and apartment buildings, hotels; >10 story heights, flat roofs	Limited grass and trees; <15% vegetation
R1	**Common Residential** Single-family dwellings with normal easements; generally one story, pitched roof structures; frequent driveways	Abundant grass lawns and lightly to moderately wooded; >70% vegetation
R2	**Compact Residential** Single, some multiple, family dwellings with close spacing; generally <2 story, pitched roof structures; garages (via alley), no driveways	Limited lawn sizes and shade trees; <30% vegetation
R3	**Compact Residential** Old multi-family dwellings with close (<2 m) lateral separation; generally 2 story, flat roof structures; garages (via alley) and ash pits, no driveways	Limited lawn sizes, old established shade trees; <35% vegetation
R4	**Estate Residential** Expensive family dwellings on multi-acre tracts	Abundant grass lawns and lightly wooded; >80% vegetation
A1	**Metropolitan Natural** Major municipal, state, or federal parks, golf courses, cemeteries, campuses; occasional single-story structures	Nearly total grass and lightly wooded; >95% vegetation
A2	**Agricultural Rural**	Local crops (e.g., corn, soybeans); 95% vegetation
A3	**Undeveloped** Uncultivated, wasteland	Mostly wild grasses and weeds, lightly wooded; >90% vegetation
A4	**Undeveloped Rural**	Heavily wooded; 95% vegetation
A5	**Water Surface** Rivers, lakes	

3.4 AMBIENT AIR QUALITY STATUS

The E. W. Brown Generating Station is located in Mercer County, Kentucky. The present air quality status of the station site and surrounding area (within a 25-kilometer radius circle from the station) is designated as attaining the NAAQS for all criteria pollutants.

4.0 DISPERSION MODELS, DATA BASES, AND ANALYSIS FOR AIR QUALITY IMPACT EVALUATION

Air quality dispersion modeling analyses were performed to assess the ambient air quality impact of the proposed modification. A detailed description of the modeling approach and data requirements for the assessment of the air quality impact due to the proposed modification is included in this section.

4.1 DESCRIPTION OF AIR QUALITY DISPERSION MODELS

The air quality modeling analyses employed USEPA's Industrial Source Complex (ISC) (Version 6, Change No. 8) and COMPLEX I (VALLEY screening option) dispersion models. The ISC model (USEPA, 1987) is recommended as a guideline model for assessing the impact of aerodynamic downwash, and the VALLEY dispersion model is recommended to assess the impact on terrain elevations higher than stack height (USEPA, 1986).

The ISC model consists of two programs: a short-term model (ISCST) and a long-term model (ISCLT). The difference in these programs is that the ISCST program utilizes an hourly meteorological data base, while ISCLT is a sector-averaged program using a frequency of occurrence based on categories of wind speed, wind direction, and atmospheric stability. Major features of the ISC model are as follows:

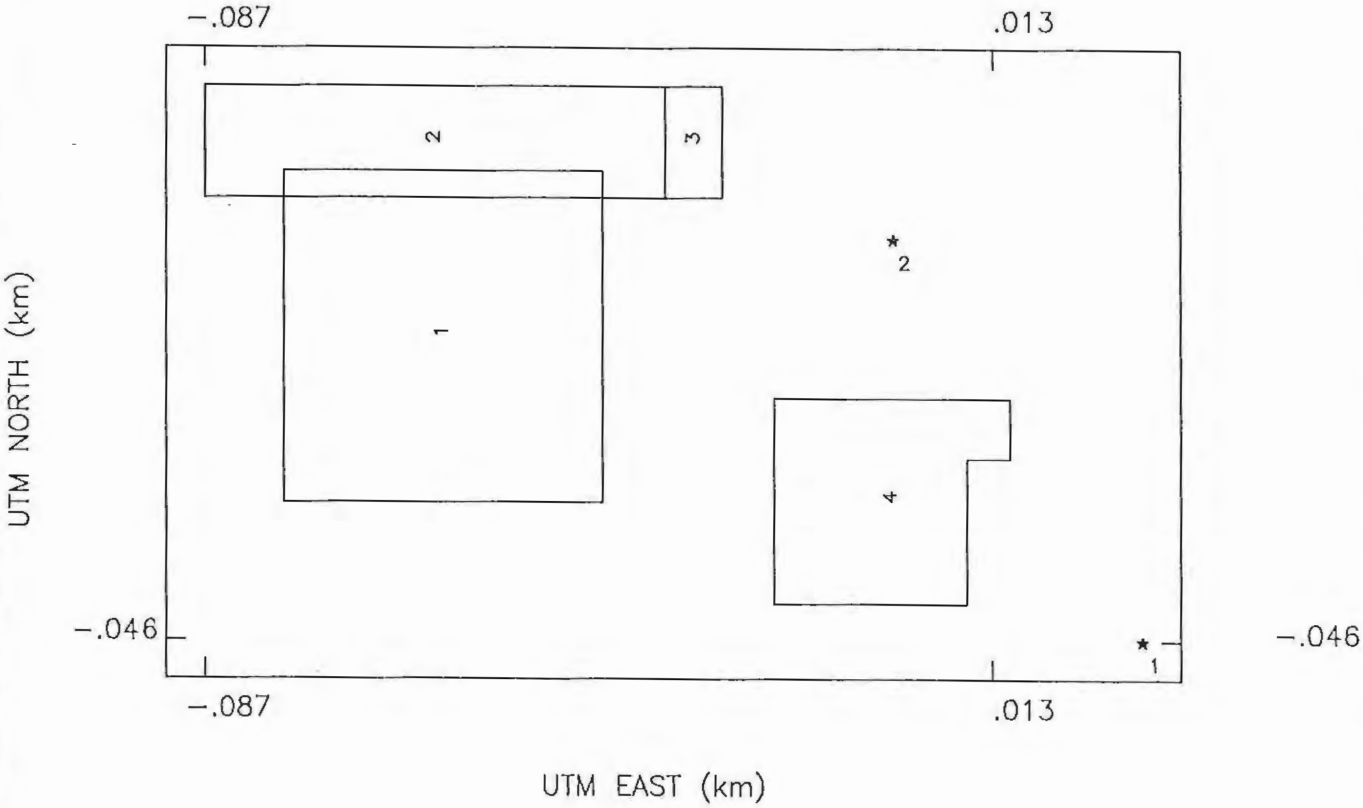
- Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1971 and 1975);
- The influence of building wakes on plume transport and dispersion is evaluated by the Huber and Snyder method (1976, 1977) for physical stack heights that are greater than $h_b + 0.5\ L_B$, where h_b is the building height and l_B is the lesser of the building height or width, and by the Schulman and Scire method (1980a, 1980b, 1985, 1986) for stack heights that are less than $h_b + 0.5\ l_B$;
- Regulatory default option;
- Calm wind treatment of NWS meteorological data;

- Buoyancy-induced plume rise algorithm;
- Procedures suggested by Briggs (1973) for evaluating stack-tip downwash;
- Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations;
- Capability of simulating line, volume, and area sources;
- Concentration estimates for 1 hour to annual average; and
- Adjustment procedures for complex terrain.

Version 6.8 has an option to treat calm wind conditions according to the USEPA policy of setting concentrations equal to zero during calm periods. Also, the regulatory default option was selected such that the USEPA guideline requirements were met. Details of the modeling algorithms employed in the ISCST may be found in the User's Guide for ISC (USEPA, 1987).

The computation of projected building dimensions was performed using the commercially-available BREEZE WAKE preprocessing program. This program builds a mathematical representation of each building. These calculations were performed for 36 different wind directions (at 10-degree intervals). For example, the BREEZE WAKE building dimensions for a wind direction orientation of 30 degrees will be used for wind directions between 25 and 35 degrees. If the BREEZE WAKE program determines that a source is under the influence of several potential building wakes, the structure or combination of structures that has the greatest influence [h_b + 0.5 (l_b)] is selected for input to the ISCST model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-caase building dimensions for that direction yield a wake region height less than the source's physical stack height, then h_b, w_b, and l_b are set equal to zero for that wind direction.

The building wake criteria influence zone is 5 l_b downwind, 2 l_b upwind, and 0.5 l_b crosswind. This criteria is based on the recommendations by the USEPA. Figure 4-1 illustrates those building structures that would have an influence on the existing boiler stacks of the E. W. Brown Station.



LEGEND:

Building *	Height (m)
1	67.36
2	44.32
3	47.87
4	45.42

Scale: 23.9 m/inch

FIGURE 4-1

LOCATION OF UNIT 1 AND 2 STACKS IN RELATION TO BUILDING STRUCTURES

Dames & Moore

The COMPLEX I dispersion model (VALLEY screening option) accounts for terrain elevations that exceed stack height (Burt, 1977). This model calculates a 24-hour average concentration based on 6 hours of a stable atmosphere (Stability Class F) occurring with unvarying wind direction and a wind speed of 2.5 m/s. The 24-hour concentration was adjusted (Turner, 1970) to estimate concentrations for annual, 1-hour, 3-hour, and 8-hour averaging periods. The worst-case ratio of the 24-hour to annual average concentration for the ISC impact analyses was used to estimate an annual average.

4.2 DATA BASES FOR AIR QUALITY EVALUATION

The data bases required for the air quality impact assessment include source emission inventory data, meteorological data, receptor points, and background concentrations.

4.2.1 Emission Inventory Data

The emission inventory for the proposed turbines is presented in Table 4-1. Kentucky Utilities is proposing to build a separate stack for each of the turbines. At this time, the turbine vendor has not been selected; thus, the stack and emission parameters for each of the three vendors has been modeled. For each vendor, a number of turbine designs are possible. Thus, the stack parameters and emission rates were chosen to represent worst-case conditions, giving KU the flexibility of choosing any turbine type. Specifically, the lowest temp, lowest volumetric flow rate, highest pollutant emission rates were modeled (and shown in Table 4-1). Thus, it is possible that the temperature, volumetric flow rate, and emission rates were taken from different turbine designs; a situation that is not physically possible and lends a degree of conservation to the modeling results. Further, the turbines will be housed in a common building with dimensions shown in Table 4-1.

According to the Kentucky Department for Environmental Protection (KDEP), the proposed turbines are the only PSD increment-consuming source in the study area. Existing major sources of SO_2 located in Mercer County, and SO_2 sources from the 21 county surrounding area with the potential to emit greater than 100 TPY, are listed in Table 4-2. These sources were screened using the "20 D" method. Specifically, any source which has a value of the ratio of emissions (expressed in tons per year) divided by distance to the proposed facility (expressed in km) greater than 20 is considered significant and should be included in demonstrations of compliance with PSD increments and NAAQS. Table 4-3 presents the

TABLE 4-1

EMISSION INVENTORY FOR THE PROPOSED TURBINES*

	VENDOR 1	VENDOR 2	VENDOR 3
Stack Height (m)	33.53	42.67	60.96
Stack Diameter (m)	4.48	5.16	4.57
Exit Velocity (m/s)	46.33	43.33	46.43
Exit Temperature (°K)	728.1	729.8	720.4
SO_2 Emission Rate (g/s)	39.50	52.92	45.55
NO_x Emission Rate[1] (g/s)	9.78	8.70	10.21
TSP Emission Rate (g/s)	1.89	8.42	5.29
PM_{10} Emission Rate (g/s)	1.89	8.42	5.29
CO Emission Rate (g/s)	7.18	9.45	3.91
Building Height (m)	12.19	18.90	18.90
Building Length (m)	176.78	173.74	155.45
Building Width (m)	24.38	18.29	15.24

*Emissions and stack data are presented for one of seven identical stacks for vendors 1 and 3 and one of eight identical stacks for vendor 2. Emission estimates were provided by the vendors.

[1]Represents annual-average emission rate assuming operation of 2,500 hrs/yr.

[d:\...\job\11927005\ku0429.t41]

TABLE 4-2

LIST OF MAJOR SO_2 SOURCES LOCATED IN THE 21 COUNTY AREA SURROUNDING MERCER COUNTY

FACILITY	COUNTY	EMISSION RATE (TPY) Q	DISTANCE TO PROPOSED TURBINES (km) D	Q/D
Boulevard Distillers	Anderson	163.405	30.63	5.33
Kraft Food	Anderson	103.25	30.82	3.35
Phillips Lighting	Boyle	411.641	17.63	23.35
East Kentucky Power Corp.	Clark	7688.436	41.56	185.0
U of Kentucky	Fayette	1869.333	33.58	55.67
Trane Co.	Fayette	127.329	35.95	3.54
IBM	Fayette	1036.896	36.96	28.05
Square D	Fayette	102.122	36.39	2.81
Jim Beam (Old Grand-Dad)	Franklin	458.023	48.05	9.53
Age Intl.	Franklin	832.847	49.31	16.89
Berea College	Madison	183.906	44.63	4.12
East Kentucky University	Madison	214.5	37.29	5.75
Jim Beam Brands	Nelson	415.897	66.04	6.30
Barton Brands	Nelson	402.128	65.57	6.13
Union Underwear	Taylor	743.856	75.93	9.80
Kentucky Utilities	Woodford	3817.966	30.79	124.0
GTE Products	Woodford	277.958	28.57	9.73
Jim Beam (Old Crow)	Woodford	693.728	40.96	16.94
GTE Products Corp.	Woodford	293.211	28.52	10.28

[d:\...\job\11927005\ku0506.t42]

TABLE 4-3

EMISSION INVENTORY OF MAJOR SO_2 EMISSION SOURCES INCLUDED IN THE AIR QUALITY IMPACT ANALYSIS

EMISSION SOURCE	UTM COORDINATES (kilometers) East	UTM COORDINATES (kilometers) North	STACK HEIGHT (m)	EXIT TEMPERATURE (°K)	EXIT VELOCITY (m/s)	STACK DIAMETER (m)	SO_2 EMISSION RATE (g/s)
E. W. Brown	701.386	4184.576	105.0	419.0	16.0	3.90	952.56
	701.354	4184.622	105.0	422.0	17.0	4.50	1310.15
	701.297	4184.555	171.0	422.0	26.0	5.60	3120.77
Phillips Lighting	695.200	4168.100	41.0	755.0	6.0	1.80	10.977
	695.200	4168.100	41.0	505.0	7.0	1.80	0.833
	695.200	4168.100	21.0	450.0	10.0	0.60	7.192
	695.200	4168.100	15.0	311.0	4.0	0.50	.031
East Kentucky Power	740.800	4196.000	45.0	433.0	4.0	3.70	19.99
	740.800	4196.000	45.0	433.0	4.0	3.70	19.99
	740.800	4196.000	45.0	444.0	11.0	3.70	229.90
	740.800	4196.000	45.0	427.0	10.0	3.70	219.09
University of Kentucky	718.900	4213.100	15.0	422.0	6.0	1.70	0.180
	719.500	4212.000	15.0	422.0	6.0	1.70	0.180
	718.800	4212.000	36.0	533.0	50.0	0.60	9.062
	719.500	4212.000	36.0	533.0	6.0	1.80	9.090
	719.500	4212.000	25.0	422.0	7.0	1.70	1.456
	719.500	4212.000	25.0	422.0	7.0	1.70	1.456
	719.500	4212.000	39.0	922.0	13.0	0.90	.04
	718.800	4211.900	8.0	1033.0	9.0	0.40	.04
	719.500	4212.000	21.0	450.0	6.0	1.80	33.167
IBM	720.000	4216.400	9.0	477.0	13.0	0.30	0.52
	720.000	4216.400	2.0	700.0	6.01	0.10	1.01
	720.000	4216.400	10.0	533.0	20.0	0.90	10.327
	720.000	4216.400	10.0	533.0	20.0	0.90	10.327
	720.000	4216.400	10.0	533.0	20.0	0.90	10.327

TABLE 4-3 - Continued

EMISSION SOURCE	UTM COORDINATES (kilometers)		STACK HEIGHT (m)	EXIT TEMPERATURE (°K)	EXIT VELOCITY (m/s)	STACK DIAMETER (m)	SO_2 EMISSION RATE (g/s)
	East	North					
	720.000	4216.400	10.0	533.0	20.0	0.90	10.327
	720.000	4216.400	10.0	533.0	20.0	0.90	10.327
	720.000	4216.400	10.0	533.0	13.0	0.90	5.839
Kentucky Utilities Tyrone	688.800	4213.200	51.0	422.0	13.0	2.50	70.16
	688.800	4213.200	51.0	422.0	13.0	2.50	70.16
	688.800	4213.200	51.0	422.0	17.0	3.40	221.35
	688.800	4213.200	18.0	450.0	8.0	0.30	0.60

[d:\...\job\11927005\ku0506.t43]

emission inventory for each source determined to have a significant impact following the "20 D" method. These sources were subsequently included in the demonstration of compliance with PSD increments and NAAQS for SO_2.

4.2.2 Meteorological Data

The meteorological data base used in the dispersion model consisted of 5 years (1983-1987) of surface observations at the Lexington Airport NWS station and the coincident upper air observations at the Dayton, Ohio Airport. Surface observations consist of hourly measurements of wind direction, wind speed, and temperature, and estimates of ceiling height and cloud cover. The upper air station provides a daily morning and afternoon mixing height value as determined from the twice-daily radiosonde measurements. These surface and upper air data were processed into a format suitable for dispersion modeling by USEPA's RAMMET program (Turner and Novak, 1978). RAMMET utilizes the Turner Classification Scheme (Turner, 1970) to estimate the dispersive capacity of the atmosphere. Using the surface observations of wind speed and cloud cover combined with an estimate of insolation based on solar altitude, a stability class category is assigned for each hour of meteorological surface data. The twice-daily mixing height values are interpolated by a USEPA scheme (USEPA, 1974) to obtain hourly mixing height values. The USEPA developed a rural and urban interpolation method to account for the effects of the surrounding area on development of the mixing layer boundary. The rural scheme was used to determine hourly mixing heights for the area near the E. W. Brown Generating Station.

4.2.3 Receptor Grid

The receptor grid for the ISC dispersion model was designed to identify the maximum air quality impact due to the proposed modification. The receptor grid consisted of 327 receptors extending to 50 kilometers from the station. The receptor grid is illustrated in Figures 4-2 and 4-3.

4.2.4 Background Concentrations

The proposed turbines will be built in an area in which there are few major emission sources. To determine SO_2 background concentrations for annual, 3-hour and 24-hour averaging periods, the "Ambient Air Quality Summary Statistical Report, January 1990 through December

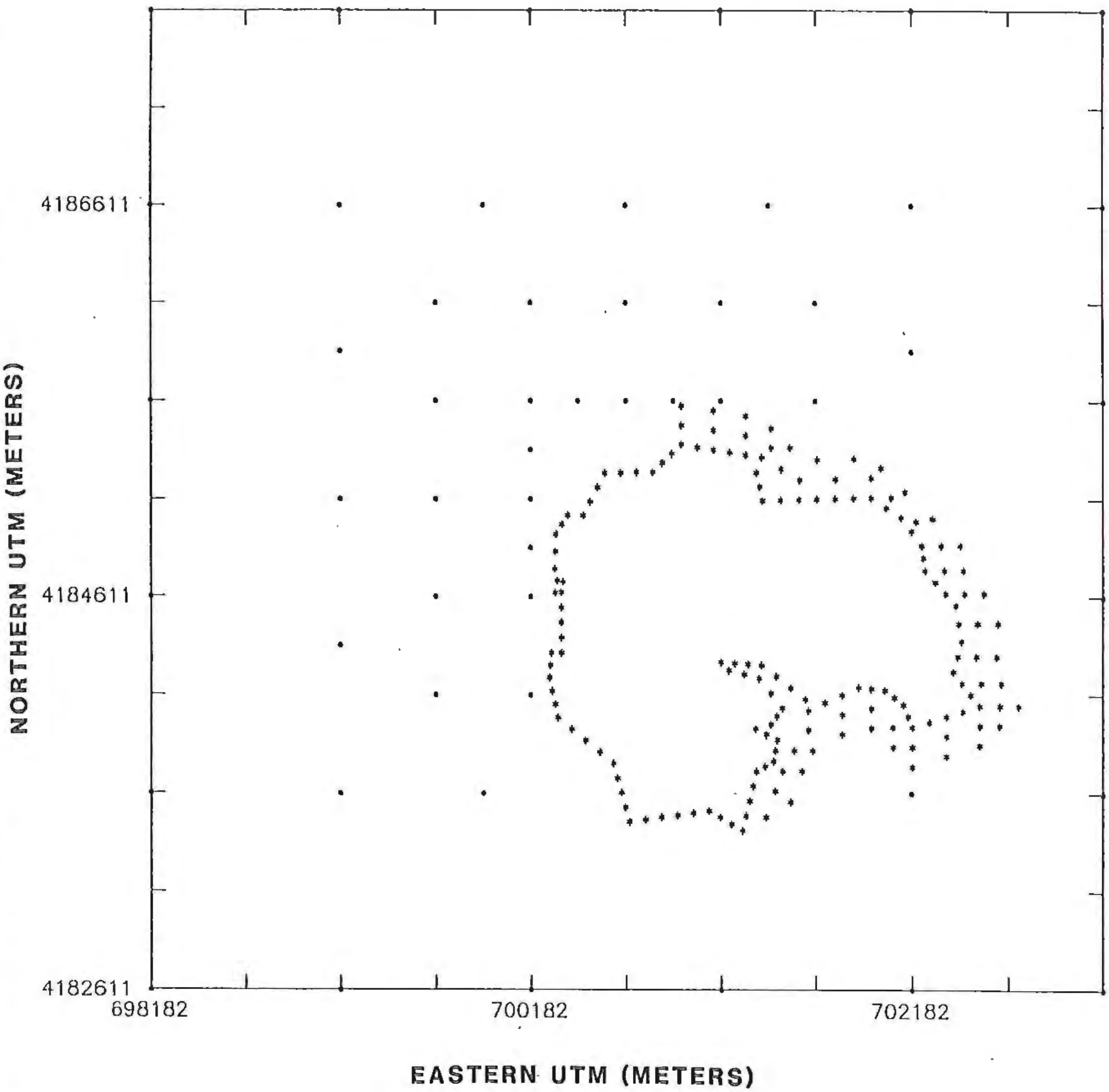


FIGURE 4-2
RECEPTOR GRID FOR
POINTS OUT TO 3.5 KILOMETERS

Dames & Moore

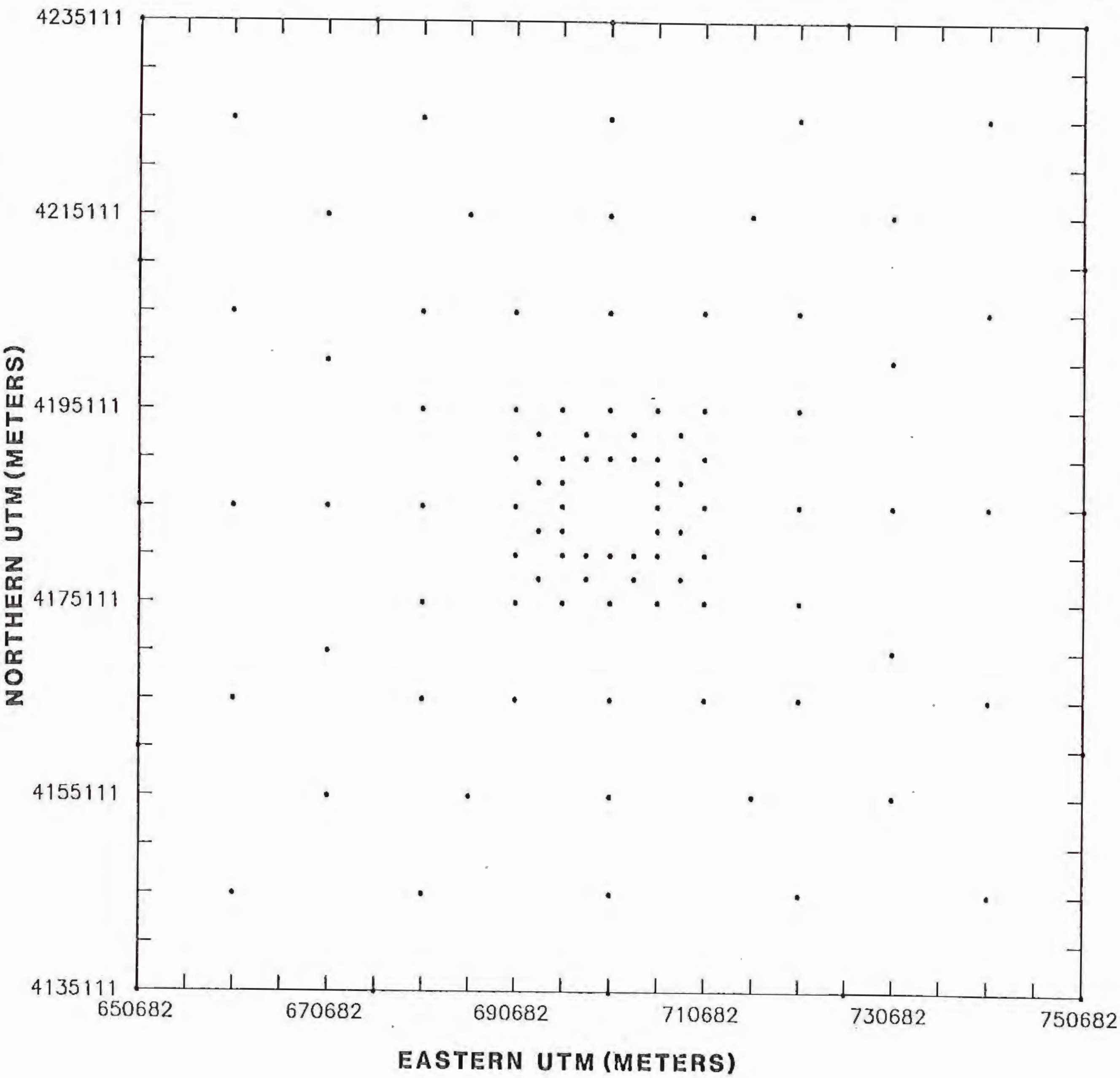


FIGURE 4-3
RECEPTOR GRID FOR
POINTS OUT TO 50 KILOMETERS

1990" was utilized. This document references a monitor located on Newtown Pike Road in Lexington. Since this is the nearest monitor to the E.W. Brown Station, the annual, 3-hour second highest, and 24-hour second-highest SO_2 concentrations at this monitor were considered representative of background concentrations for the dispersion modeling analyses. Specifically, the following SO_2 concentrations were extracted from the reference:

Annual	15.7 $\mu g/m^3$
3-hour second-highest	104.8 $\mu g/m^3$
24-hour second-highest	55.0 $\mu g/m^3$

These background concentrations for SO_2 have been added to the maximum predicted concentrations due to all major emission sources for comparison with NAAQS.

5.0 AMBIENT AIR QUALITY IMPACT ASSESSMENT

Air quality dispersion modeling analyses to support the PSD application for the proposed turbines include the following:

- Determine the significant impact area for each pollutant;
- For pollutants having a significant impact, determine compliance with the PSD increments and NAAQS; and
- Determine whether the proposed modification is subject to a 1-year ambient air quality monitoring program.

The results of these analyses are presented below. Diskettes of the dispersion model input and output files are provided in Appendix B in one of the copies submitted to KDEP. In addition, Appendix C contains hard copy output from the worst case year of ISCST modeling.

5.1 DETERMINATION OF SIGNIFICANT IMPACT AREAS

The significant impact area is defined as the area in which predicted concentrations, due to the proposed modification exceed specified significant impact increments (refer to Table 1-1) on a pollutant-specific basis. Further, for pollutants which have significant impact increments for several averaging periods, the significant impact area for these pollutants is derived by overlaying the concentration isopleths for each averaging period to define the extreme extent of the impact area. In the event the dispersion modeling analyses result in predicted concentrations which are less that the significant impact increments for a pollutant, then additional analyses for that pollutant are not necessary. The ISCST dispersion modeling results for the proposed modification's impact on SO_2, NO_x, CO, and TSP/PM_{10} concentrations are presented in Tables 5-1 through 5-3 for each of the three turbine vendors. Table 5-4 presents the results of the COMPLEX I model.

Total Suspended Particulate/Particulate Matter Less than 10 Microns -- The air quality impact analyses were performed assuming the PM_{10} emissions were equal to TSP emissions. The maximum predicted annual average and highest 24-hour average TSP/PM_{10} concentrations are 0.20 and 2.0 $\mu g/m^3$, respectively. These concentrations are

TABLE 5-1

COMPARISON OF ISCST MAXIMUM PREDICTED CONCENTRATIONS DUE TO THE PROPOSED MODIFICATION (VENDOR 1) WITH SIGNIFICANT IMPACT INCREMENTS

POLLUTANT	AVERAGING PERIOD	DATA PERIOD			UTM RECEPTOR LOCATION (kilometers)		PREDICTED CONCENTRATION ($\mu g/m^3$)	SIGNIFICANT IMPACT INCREMENT ($\mu g/m^3$)
		DATA YEAR	JULIAN DAY	HOUR ENDING	EASTING	NORTHING		
SO_2	Annual	1983	–	–	700.682	4205.111	0.695	1
		1984	–	–	700.682	4205.111	0.649	
		1985	–	–	700.682	4205.111	0.818	
		1986	–	–	700.682	4205.111	0.828	
		1987	–	–	700.682	4205.111	0.589	
	3-Hour Highest	1983	174	12	702.337	4184.874	39.165	25
		1984	190	12	699.182	4185.111	41.032	
		1985	313	24	700.682	4205.111	34.783	
		1986	169	15	700.472	4183.880	40.790	
		1987	133	12	699.182	4185.111	42.121	
	24-Hour Highest	1983	129	24	693.182	4182.611	9.289	5
		1984	204	24	698.182	4183.611	7.534	
		1985	146	24	700.682	4205.111	8.342	
		1986	253	24	700.682	4205.111	10.106	
		1987	319	24	695.682	4190.111	9.682	
NOx	Annual	1983	–	–	700.682	4205.111	0.17	1
		1984	–	–	700.682	4205.111	0.16	
		1985	–	–	700.682	4205.111	0.20	
		1986	–	–	700.682	4205.111	0.21	
		1987	–	–	700.682	4205.111	0.15	

TABLE 5-1 - Continued

POLLUTANT	AVERAGING PERIOD	DATA PERIOD			UTM RECEPTOR LOCATION (kilometers)		PREDICTED CONCENTRATION ($\mu g/m^3$)	SIGNIFICANT IMPACT INCREMENT ($\mu g/m^3$)
		DATA YEAR	JULIAN DAY	HOUR ENDING	EASTING	NORTHING		
CO	1-Hour Highest	1983	174	11	702.307	4184.687	15.59	2000
		1984	138	11	699.682	4184.611	13.09	
		1985	127	12	700.326	4183.995	16.17	
		1986	150	12	702.246	4184.811	15.89	
		1987	149	11	702.237	4184.874	17.31	
	8-Hour Highest	1983	146	8	700.682	4165.111	2.98	500
		1984	189	8	700.682	4165.111	3.43	
		1985	342	8	700.682	4205.111	3.27	
		1986	115	16	705.682	4187.611	3.70	
		1987	319	8	695.682	4190.111	4.44	
TSP/PM_{10}	Annual	1983	–	–	700.682	4205.111	0.03	1
		1984	–	–	700.682	4205.111	0.03	
		1985	–	–	700.682	4205.111	0.04	
		1986	–	–	700.682	4205.111	0.04	
		1987	–	–	700.682	4205.111	0.03	
	24-Hour Highest	1983	129	24	693.182	4182.611	0.44	5
		1984	204	24	698.182	4183.611	0.36	
		1985	146	24	700.682	4205.111	0.40	
		1986	253	24	700.682	4205.111	0.48	
		1987	319	24	695.682	4190.111	0.46	

[d:\...\job\11927005\ku0429.t51]

TABLE 5-2

COMPARISON OF ISCST MAXIMUM PREDICTED CONCENTRATIONS DUE TO THE PROPOSED MODIFICATION (VENDOR 2) WITH SIGNIFICANT IMPACT INCREMENTS

POLLUTANT	AVERAGING PERIOD	DATA PERIOD			UTM RECEPTOR LOCATION (kilometers)		PREDICTED CONCENTRATION ($\mu g/m^3$)	SIGNIFICANT IMPACT INCREMENT ($\mu g/m^3$)
		DATA YEAR	JULIAN DAY	HOUR ENDING	EASTING	NORTHING		
SO_2	Annual	1983	–	–	700.682	4205.111	0.729	1
		1984	–	–	700.682	4205.111	0.694	
		1985	–	–	700.682	4205.111	0.882	
		1986	–	–	700.682	4205.111	0.873	
		1987	–	–	700.682	4205.111	0.605	
	3-Hour Highest	1983	146	3	700.682	4165.111	42.953	25
		1984	289	3	695.682	4190.111	45.139	
		1985	264	24	695.682	4190.111	41.875	
		1986	169	15	700.544	4183.822	59.144	
		1987	116	6	700.682	4165.111	51.044	
	24-Hour Highest	1983	129	24	693.182	4182.611	10.203	5
		1984	111	24	680.682	4165.111	8.254	
		1985	146	24	700.682	4205.111	9.277	
		1986	253	24	700.682	4205.111	10.822	
		1987	319	24	695.682	4190.111	12.011	
NOx	Annual	1983	–	–	700.682	4205.111	0.12	1
		1984	–	–	700.682	4205.111	0.11	
		1985	–	–	700.682	4205.111	0.14	
		1986	–	–	700.682	4205.111	0.14	
		1987	–	–	700.682	4205.111	0.10	

TABLE 5-2 - Continued

POLLUTANT	AVERAGING PERIOD	DATA PERIOD: DATA YEAR	DATA PERIOD: JULIAN DAY	DATA PERIOD: HOUR ENDING	UTM RECEPTOR LOCATION (kilometers): EASTING	UTM RECEPTOR LOCATION (kilometers): NORTHING	PREDICTED CONCENTRATION ($\mu g/m^3$)	SIGNIFICANT IMPACT INCREMENT ($\mu g/m^3$)
CO	1-Hour Highest	1983	218	12	702.428	4184.476	18.73	2000
		1984	138	11	699.682	4184.611	18.66	
		1985	215	12	700.682	4186.611	20.06	
		1986	169	13	700.544	4183.822	18.22	
		1987	206	11	700.682	4186.611	21.16	
	8-Hour Highest	1983	265	8	720.682	4205.111	3.73	500
		1984	189	8	700.682	4165.111	4.22	
		1985	264	24	695.682	4190.111	3.68	
		1986	115	16	705.682	4187.611	4.35	
		1987	319	8	695.682	4190.111	5.32	
TSP/PM_{10}	Annual	1983	–	–	700.682	4205.111	0.12	1
		1984	–	–	700.682	4205.111	0.11	
		1985	–	–	700.682	4205.111	0.14	
		1986	–	–	700.682	4205.111	0.14	
		1987	–	–	700.682	4205.111	0.10	
	24-Hour Highest	1983	129	24	693.182	4182.611	1.62	5
		1984	111	24	680.682	4165.111	1.31	
		1985	146	24	700.682	4205.111	1.48	
		1986	253	24	700.682	4205.111	1.72	
		1987	319	24	695.682	4190.111	1.91	

[d:\...\job\11927005\ku0429.t52]

TABLE 5-3

COMPARISON OF ISCST MAXIMUM PREDICTED CONCENTRATIONS DUE TO THE PROPOSED MODIFICATION (VENDOR 3) WITH SIGNIFICANT IMPACT INCREMENTS

POLLUTANT	AVERAGING PERIOD	DATA PERIOD			UTM RECEPTOR LOCATION (kilometers)		PREDICTED CONCENTRATION ($\mu g/m^3$)	SIGNIFICANT IMPACT INCREMENT ($\mu g/m^3$)
		DATA YEAR	JULIAN DAY	HOUR ENDING	EASTING	NORTHING		
SO_2	Annual	1983	–	–	700.682	4205.111	0.501	1
		1984	–	–	700.682	4205.111	0.480	
		1985	–	–	700.682	4205.111	0.602	
		1986	–	–	700.682	4205.111	0.608	
		1987	–	–	700.682	4205.111	0.400	
	3-Hour Highest	1983	174	12	702.337	4184.874	43.375	25
		1984	190	12	699.182	4185.111	45.677	
		1985	127	12	700.326	4183.995	33.114	
		1986	169	15	700.472	4183.880	45.453	
		1987	133	12	699.182	4185.111	46.825	
	24-Hour Highest	1983	114	24	700.682	4165.111	7.259	5
		1984	195	24	700.701	4183.467	7.792	
		1985	208	24	680.682	4165.111	6.245	
		1986	115	24	705.682	4187.611	7.312	
		1987	319	24	695.682	4190.111	7.631	
NOx	Annual	1983	–	–	700.682	4205.111	0.11	1
		1984	–	–	700.682	4205.111	0.11	
		1985	–	–	700.682	4205.111	0.13	
		1986	–	–	700.682	4205.111	0.14	
		1987	–	–	700.682	4205.111	0.09	

TABLE 5-3 - Continued

POLLUTANT	AVERAGING PERIOD	DATA PERIOD			UTM RECEPTOR LOCATION (kilometers)		PREDICTED CONCENTRATION ($\mu g/m^3$)	SIGNIFICANT IMPACT INCREMENT ($\mu g/m^3$)
		DATA YEAR	JULIAN DAY	HOUR ENDING	EASTING	NORTHING		
CO	1-Hour Highest	1983	174	11	702.307	4184.687	8.23	2000
		1984	138	11	699.682	4184.611	6.88	
		1985	127	12	700.326	4183.995	8.52	
		1986	150	12	702.246	4184.811	8.39	
		1987	149	11	702.237	4184.874	9.14	
	8-Hour Highest	1983	174	16	702.337	4184.874	1.40	500
		1984	111	8	680.682	4165.111	1.73	
		1985	123	24	690.682	4165.111	1.47	
		1986	115	16	705.682	4187.611	1.85	
		1987	319	8	695.682	4190.111	1.59	
TSP/PM_{10}	Annual	1983	–	–	700.682	4205.111	0.06	1
		1984	–	–	700.682	4205.111	0.06	
		1985	–	–	700.682	4205.111	0.07	
		1986	–	–	700.682	4205.111	0.07	
		1987	–	–	700.682	4205.111	0.05	
	24-Hour Highest	1983	114	24	700.682	4165.111	0.84	5
		1984	195	24	700.701	4183.467	0.90	
		1985	208	24	680.682	4165.111	0.73	
		1986	115	24	705.682	4187.611	0.85	
		1987	319	24	695.682	4190.111	0.89	

TABLE 5-4

COMPARISON OF MAXIMUM PREDICTED CONCENTRATIONS DUE TO THE PROPOSED MODIFICATION WITH SIGNIFICANT IMPACT INCREMENTS AND MONITORING DE MINIMIS CONCENTRATIONS (COMPLEX I - VALLEY SCREENING MODEL)

POLLUTANT	AVERAGING PERIOD	PREDICTED CONCENTRATIONS ($\mu g/m^3$)			SIGNIFICANT IMPACT INCREMENT ($\mu g/m^3$)	MONITORING DE MINIMIS CONCENTRATION ($\mu g/m^3$)
		VENDOR 1	VENDOR 2	VENDOR 3		
SO_2	Annual[a]	1.05	1.24	0.89	1	
	3-Hour[b]	16.21	19.31	13.85	25	
	24-Hour	10.67	12.70	9.11	5	13
NO_x	Annual[a]	0.26	0.20	0.20	1	14
CO	1-Hour[c]	3.66	4.29	1.48	2000	
	8-Hour[d]	2.42	2.84	0.98	500	575
TSP/PM_{10}	Annual[a]	0.05	0.20	0.10	1	
	24-Hour	0.51	2.02	1.06	5	10

a To represent an annual average concentration, the predicted 24-hour average concentration was multiplied by a factor of 0.098 (worst-case ratio of 24-hour to annual from ISC modeling).

b To represent a 3-hour average concentration, the predicted 24-hour average concentration was multiplied by a factor of 1.52 (Turner, 1970).

c To represent a 1-hour average concentration, the predicted 24-hour average concentration was multiplied by a factor of 1.89 (Turner, 1970).

d To represent an 8-hour average concentration, the predicted 24-hour average concentration was multiplied by a factor of 1.25 (Turner, 1970).

[d:\...\job\11927005\ka0429.t54]

below the corresponding significant impact increments of 1 and 5 $\mu g/m^3$; thus, additional air quality impact analyses for TSP/PM_{10} are not required.

<u>**Carbon Monoxide**</u> -- The maximum predicted highest 1-hour and 8-hour average CO concentrations due to the proposed modification are 21.2 and 5.3 $\mu g/m^3$, respectively. Additional air quality impact analyses for CO are not required because these concentrations are well below the corresponding 1-hour and 8-hour average significant impact increments of 2000 and 500 $\mu g/m^3$.

<u>**Nitrogen Dioxide**</u> -- The maximum predicted annual average NO_2 concentration was 0.21 $\mu g/m^3$ with the ISCST model and 0.26 $\mu g/m^3$ with the COMPLEX I (VALLEY screening model). These concentrations are below the corresponding significant impact increment of 1 $\mu g/m^3$; thus, additional air quality impact analyses to demonstrate compliance with the PSD increments and NAAQS for NO_2 are not required.

<u>**Sulfur Dioxide**</u> -- The maximum predicted annual, 24-hour, and 3-hour average SO_2 concentrations with the ISCST model are are 0.88, 12.0, and 59.1 $\mu g/m^3$, respectively. The maximum predicted concentrations with COMPLEX I model were 1.24, 12.7, and 19.3 $\mu g/m^3$ for the annual, 24-hour, and 3-hour average periods. These concentrations are above the corresponding significant impact increments of 1, 5, and 25 $\mu g/m^3$; thus, additional air quality impact analyses for SO_2 are required. The significant impact area extends 50 kilometers from the E. W. Brown Station.

5.2 PREVENTION OF SIGNIFICANT DETERIORATION INCREMENT ASSESSMENT

According to the KDEP, the only PSD increment consuming source within the significant impact area is the proposed turbine project. The maximum predicted SO_2 concentrations for each vendor with the ISCST and COMPLEX I model are presented in Tables 5-5 through 5-8. The maximum increment consumption for an annual average period is 1.24 $\mu g/m^3$, which is below the PSD Class II increment of 20 $\mu g/m^3$. The maximum increment consumption for the 3-hour and 24-hour averaging periods are 44.2 and 12.7 $\mu g/m^3$, respectively, which are well below the corresponding PSD Class II increments of 512 and 91 $\mu g/m^3$.

TABLE 5-5

COMPARISON OF ISCST MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE PSD INCREMENTS (VENDOR 1)

AVERAGING PERIOD	DATA PERIOD			RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	PSD CLASS II INCREMENT ($\mu g/m^3$)
	Year	Day	Hour Ending	East	North		
Annual	1983	--	--	700.682	4205.111	.695	20
	1984	--	--	700.682	4205.111	.649	
	1985	--	--	700.682	4205.111	.818	
	1986	--	--	700.682	4205.111	.828	
	1987	--	--	700.682	4205.111	.589	
3-Hour Highest, Second-Highest	1983	28	21	693.182	4187.611	31.080	512
	1984	337	3	695.682	4190.111	33.595	
	1985	158	6	695.682	4190.111	33.804	
	1986	81	24	700.682	4205.111	34.627	
	1987	325	3	695.682	4190.111	36.634	
24-Hour Highest, Second-Highest	1983	111	24	693.182	4182.611	7.182	91
	1984	326	24	690.682	4175.111	6.618	
	1985	313	24	700.682	4205.111	7.540	
	1986	31	24	700.682	4205.111	7.372	
	1987	326	24	695.682	4190.111	7.178	

[d:\...\job\11927005\ku0507.t55]

TABLE 5-6

COMPARISON OF ISCST MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE PSD INCREMENTS (VENDOR 2)

AVERAGING PERIOD	DATA PERIOD			RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	PSD CLASS II INCREMENT ($\mu g/m^3$)
	Year	Day	Hour Ending	East	North		
Annual	1983	--	--	700.682	4205.111	.729	20
	1984	--	--	700.682	4205.111	.694	
	1985	--	--	700.682	4205.111	.882	
	1986	--	--	700.682	4205.111	.873	
	1987	--	--	700.682	4205.111	.605	
3-Hour Highest, Second-Highest	1983	159	15	701.821	4183.910	34.054	512
	1984	337	3	695.682	4190.111	41.100	
	1985	158	6	695.682	4190.111	40.733	
	1986	301	3	700.682	4205.111	37.528	
	1987	326	3	695.682	4190.111	44.228	
24-Hour Highest, Second-Highest	1983	130	24	693.182	4182.611	8.021	91
	1984	326	24	680.682	4165.111	7.606	
	1985	313	24	700.682	4205.111	8.548	
	1986	81	24	700.682	4205.111	8.470	
	1987	326	24	695.682	4190.111	8.796	

[d:\...\job\11927005\ku-0507.t56]

TABLE 5-7

COMPARISON OF ISCST MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE PSD INCREMENTS (VENDOR 3)

AVERAGING PERIOD	DATA PERIOD			RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	PSD CLASS II INCREMENT ($\mu g/m^3$)
	Year	Day	Hour Ending	East	North		
Annual	1983	--	--	700.682	4205.111	.501	20
	1984	--	--	700.682	4205.111	.480	
	1985	--	--	700.682	4205.111	.602	
	1986	--	--	700.682	4205.111	.608	
	1987	--	--	700.682	4205.111	.400	
3-Hour Highest, Second-Highest	1983	159	12	702.149	4185.150	31.985	512
	1984	137	21	680.682	4165.111	29.078	
	1985	223	12	701.977	4184.143	27.148	
	1986	144	15	699.682	4184.111	28.708	
	1987	169	12	702.237	4184.874	32.720	
24-Hour Highest, Second-Highest	1983	146	24	700.682	4165.111	6.252	91
	1984	111	24	680.682	4165.111	7.061	
	1985	213	24	690.682	4165.111	5.846	
	1986	8	24	660.682	4165.111	6.087	
	1987	227	24	702.182	4185.861	5.380	

[d:\...\job\11927005\ku-0507.t57]

TABLE 5-8

COMPARISON OF COMPLEX I MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE PSD INCREMENTS

VENDOR	AVERAGING PERIOD	RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	PSD CLASS II INCREMENT ($\mu g/m^3$)
		East	North		
1	Annual[a]	710.556	4148.571	1.05	20
	3-Hour[b]	710.556	4148.571	16.21	512
	24-Hour	710.556	4148.571	10.67	91
2	Annual[a]	710.556	4148.571	1.24	20
	3-Hour[b]	710.556	4148.571	19.31	512
	24-Hour	710.556	4148.571	12.70	91
3	Annual[a]	710.556	4148.571	0.89	20
	3-Hour[b]	710.556	4148.571	13.85	512
	24-Hour	710.556	4148.571	9.11	91

[a] To represent an annual average concentration, the predicted 24-hour average concentration was multiplied by a factor of .098 (worst-case ratio of 24-hour to annual from ISC modeling).

[b] To represent a 3-hour average concentration, the predicted 24-hour average concentration was multiplied by a factor of 1.52 (Turner, 1970).

[d:\...\job\11927005\ku0507.t58]

There are no PSD Class I areas within 100 kilometers of the station; thus dispersion modeling analyses were not performed for distant Class I areas.

5.3 COMPARISON WITH NATIONAL AMBIENT AIR QUALITY STANDARDS

One of the PSD review requirements is to demonstrate compliance with NAAQS for each pollutant in which the proposed turbines have a significant impact. Since SO_2 has a significant impact, the proposed turbines were modeled along with other major SO_2 emission sources and the maximum predicted concentrations due to these sources were added to representative background concentrations for comparison with NAAQS. The ISCST model results are presented in Tables 5-9 through 5-11 for the three vendors. The COMPLEX I model results are presented in Tables 5-12. The maximum annual average SO_2 concentration of 59.9 $\mu g/m^3$ complies with the NAAQS of 80 $\mu g/m^3$. The highest second-highest 3-hour and 24-hour concentrations of 2886.5 and 444.9 $\mu g/m^3$, exceed the corresponding NAAQS of 1300 and 365 $\mu g/m^3$. It is noted that the predicted concentrations are almost identical for the three vendors, which is a result of a predominant existing source. The results of an emission source culpability analysis for each predicted exceedance of the 24-hour average NAAQS are provided on Tables 5-13 through 5-15. The predominant sources are KU's coal-fired boilers of the E. W. Brown Station. It should be noted that the proposed turbines have an insignificant impact on all of the 3-hour and 24-hour average SO_2 NAAQS exceedances. The receptors having predicted exceedances of the SO_2 NAAQS are depicted in Figure 5-1.

Since the predicted exceedances of the NAAQS are primarily due to the E. W. Brown Station, KU will demonstrate compliance of the NAAQS prior to the operation of the proposed turbines. The following several control strategies of the existing coal-fired units may be considered to eliminate the modeled nonattainment area:

a) Refine the dispersion modeling analyses:

- * Verify maximum exit gas temperature and volume flow rate for Units 1 and 2;

- * Perform modeling analyses which allow for the recognition of wind-direction-dependent building dimensions for stack height to building height ratios greater than 1.5. The USEPA <u>guideline</u> ISC model allows using

TABLE 5-9

COMPARISON OF ISCST MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE NAAQS (VENDOR 1)

AVERAGING PERIOD	DATA PERIOD			RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	BACKGROUND CONCENTRATION ($\mu g/m^3$)	TOTAL CONCENTRATION ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
	YEAR	DAY	HOUR ENDING	EAST	NORTH				
Annual	1983	--	--	701.228	4185.348	38.986	15.7	54.686	80
	1984	--	--	701.228	4185.348	41.977	15.7	57.677	
	1985	--	--	701.228	4185.348	42.189	15.7	57.889	
	1986	--	--	701.228	4185.348	42.815	15.7	58.515	
	1987	--	--	701.228	4185.348	44.207	15.7	59.907	
3-Hour Highest Second-Highest	1983	296	3	701.403	4185.104	2380.943	104.8	2485.743	1300
	1984	348	15	701.499	4185.107	2781.740	104.8	2886.540	
	1985	339	9	701.594	4185.109	1945.638	104.8	2050.438	
	1986	155	9	701.386	4185.175	1741.677	104.8	1846.477	
	1987	229	9	701.403	4185.104	1729.499	104.8	1834.299	
24-Hour Highest Second-Highest	1983	155	24	703.182	4183.611	389.789	55	444.789	365
	1984	204	24	698.182	4182.611	389.529	55	444.529	
	1985	119	24	699.182	4182.611	353.458	55	408.458	
	1986	204	24	699.932	4183.611	381.930	55	436.930	
	1987	136	24	700.544	4183.822	380.665	55	435.665	

[d:\...\job\11927005\ku0603.t59]

TABLE 5-10

COMPARISON OF ISCST MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE NAAQS (VENDOR 2)

AVERAGING PERIOD	DATA PERIOD			RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	BACKGROUND CONCENTRATION ($\mu g/m^3$)	TOTAL CONCENTRATION ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
	YEAR	DAY	HOUR ENDING	EAST	NORTH				
Annual	1983	–	–	701.228	4185.348	38.982	15.7	54.682	80
	1984	–	–	701.228	4185.348	41.974	15.7	57.674	
	1985	–	–	701.228	4185.348	42.187	15.7	57.887	
	1986	–	–	701.228	4185.348	42.812	15.7	58.512	
	1987	–	–	701.228	4185.348	44.204	15.7	59.904	
3-Hour Highest Second-Highest	1983	296	3	701.403	4185.104	2380.946	104.8	2485.746	1300
	1984	348	15	701.499	4185.107	2781.740	104.8	2886.540	
	1985	339	9	701.594	4185.109	1945.638	104.8	2050.438	
	1986	155	9	701.386	4185.175	1741.677	104.8	1846.477	
	1987	229	9	701.403	4185.104	1729.499	104.8	1834.299	
24-Hour Highest Second-Highest	1983	155	24	703.182	4183.611	389.651	55	444.651	365
	1984	204	24	698.182	4182.611	389.150	55	444.150	
	1985	119	24	699.182	4182.611	353.629	55	408.629	
	1986	204	24	699.932	4183.611	381.717	55	436.717	
	1987	136	24	700.544	4183.822	380.665	55	435.665	

[d:\...\job\11927005\ku0603-t.510]

TABLE 5-11

COMPARISON OF ISCST MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE NAAQS (VENDOR 3)

AVERAGING PERIOD	DATA PERIOD			RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	BACKGROUND CONCENTRATION ($\mu g/m^3$)	TOTAL CONCENTRATION ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
	YEAR	DAY	HOUR ENDING	EAST	NORTH				
Annual	1983	–	–	701.228	4185.348	38.976	15.7	54.676	80
	1984	–	–	701.228	4185.348	41.970	15.7	57.670	
	1985	–	–	701.228	4185.348	42.182	15.7	57.882	
	1986	–	–	701.228	4185.348	42.805	15.7	58.505	
	1987	–	–	701.228	4185.348	44.199	15.7	59.899	
3-Hour Highest Second-Highest	1983	296	3	701.403	4185.104	2380.943	104.8	2485.743	1300
	1984	348	15	701.499	4185.107	2781.740	104.8	2886.540	
	1985	339	9	701.594	4185.109	1945.638	104.8	2050.438	
	1986	155	9	701.386	4185.175	1741.677	104.8	1846.477	
	1987	229	9	701.403	4185.104	1729.499	104.8	1834.299	
24-Hour Highest Second-Highest	1983	155	24	703.182	4183.611	389.901	55	444.901	365
	1984	204	24	698.182	4182.611	389.393	55	444.393	
	1985	119	24	699.182	4182.611	353.442	55	408.442	
	1986	204	24	699.932	4183.611	381.860	55	436.860	
	1987	136	24	700.544	4183.822	380.665	55	435.665	

[d:\...\job\11927005\ku0603-t.511]

TABLE 5-12

COMPARISON OF COMPLEX I MAXIMUM PREDICTED SO_2 CONCENTRATIONS WITH APPLICABLE NAAQS

VENDOR	AVERAGING PERIOD	RECEPTOR LOCATION (kilometers)		MAXIMUM PREDICTED CONCENTRATION ($\mu g/m^3$)	BACKGROUND CONCENTRATION ($\mu g/m^3$)	TOTAL CONCENTRATION ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
		East	North				
1	Annual[a]	700.682	4155.111	22.30	15.7	38.00	80
	3-Hour[b]	700.682	4155.111	345.97	104.8	450.77	1300
	24-Hour	700.682	4155.111	227.61	55	282.61	365
2	Annual[a]	700.682	4155.111	22.53	15.7	38.23	80
	3-Hour[b]	700.682	4155.111	349.45	104.8	454.25	1300
	24-Hour	700.682	4155.111	229.90	55	284.90	365
3	Annual[a]	700.682	4155.111	22.05	15.7	37.75	80
	3-Hour[b]	700.682	4155.111	341.96	104.8	446.76	1300
	24-Hour	700.682	4155.111	224.97	55	279.97	365

a To represent an annual average concentration, the predicted 24-hour average concentration was multiplied by a factor of .098 (worst-case ratio of 24-hour to annual from ISC modeling).

b To represent a 3-hour average concentration, the predicted 24-hour average concentration was multiplied by a factor of 1.52.

[d:\...\job\11927005\ku0507-T.512]

TABLE 5-13

CULPABILITIES ON NAAQS 24-HOUR HIGHEST, SECOND-HIGHEST DAY/RECEPTOR VIOLATIONS FOR SO_2

VENDOR 1

YEAR	UTM RECEPTOR (km)	DAY	7 TURBINES (33.53m)	EW BROWN	PHILLIPS	EAST KY POWER	U OF K	IBM	KU TYRONE	ALL
1983	701.403 4185.104	148	0	325.712	.004	0	0	0	0	325.716
1983	701.228 4185.348	247	0	351.119	.028	0	0	0	0	351.147
1983	700.399 4183.937	272	.005	301.981	0	11.309	.080	.066	0	313.440
1983	700.824 4185.247	318	0	357.299	0	0	0	0	0	357.299
1983	700.182 4184.111	19	.059	311.823	0	6.350	.450	.001	0	318.683
1983	699.932 4183.611	272	.079	325.224	0	11.371	.078	.069	0	336.821
1983	703.182 4185.611	116	.420	319.185	.085	0	0	0	0	319.690
1983	703.182 4183.611	155	4.845	384.944	0	0	0	0	0	389.789
1983	703.182 4184.611	204	1.549	341.799	.081	0	0	0	0	343.430
1984	701.228 4185.348	359	0	349.949	.262	0	0	0	.583	350.795
1984	701.499 4185.107	348	0	355.929	.129	0	0	0	0	356.059
1984	699.932 4183.611	204	.159	355.016	0	1.062	.189	.012	0	356.438
1984	698.182 4182.611	204	2.931	384.252	0	1.814	.440	.047	0	389.484
1985	701.228 4185.348	132	0	327.932	.048	0	0	0	0	327.981
1985	699.932 4183.611	178	.053	324.291	0	2.660	.403	.509	0	327.916
1985	699.182 4182.611	119	1.530	349.187	0	2.078	.510	.052	0	353.356
1986	701.228 4185.348	302	.030	342.012	.001	0	0	0	0	342.043
1986	700.472 4183.880	356	.011	337.335	0	.469	.022	.292	0	338.129
1986	700.326 4183.995	204	.033	347.424	0	.066	.217	.119	0	347.858
1986	700.739 4185.246	264	.008	335.092	.030	.532	.094	.169	.001	335.926

TABLE 5-13 - Continued

YEAR	UTM RECEPTOR (km)	DAY	7 TURBINES (33.53m)	EW BROWN	PHILLIPS	EAST KY POWER	U OF K	IBM	KU TYRONE	ALL
1986	700.399 4183.937	203	1.080	340.868	0	.358	.609	.179	0	343.093
1986	700.311 4184.063	291	0	344.138	0	3.284	.002	0	0	347.424
1986	699.932 4183.611	204	.655	380.585	0	.072	.225	.121	0	381.658
1986	698.182 4182.611	204	3.741	308.974	0	.080	.318	.144	0	313.257
1986	703.182 4184.611	150	4.833	314.944	.085	0	0	0	0	319.862
1987	700.472 4183.880	80	.012	350.335	0	1.534	1.097	.973	.159	354.110
1987	700.326 4183.995	81	0	314.400	.002	.458	.161	.298	0	315.319
1987	700.544 4183.822	136	0	378.195	0	2.316	.086	.068	0	380.666

[d:\...\job\11927005\kentt0514.tbl]

TABLE 5-14

EMISSION SOURCE CULPABILITIES FOR EXCEEDANCES OF THE 24-HOUR AVERAGE SO_2 NAAQS (VENDOR 2)

YEAR	UTM RECEPTOR (km)	DAY	8 TURBINES (42.67 m)	EW BROWN	PHILLIPS	EAST KY POWER	U OF K	IBM	KU TYRONE	ALL
1983	701.403 4185.104	148	0	325.712	.004	0	0	0	0	325.716
1983	701.228 4185.348	247	0	351.119	.028	0	0	0	0	351.147
1983	700.399 4183.937	272	.002	301.981	0	11.309	.080	.066	0	313.436
1983	700.824 4185.247	318	0	357.299	0	0	0	0	0	357.299
1983	700.182 4184.111	19	.054	311.823	0	6.350	.450	.001	0	318.677
1983	699.932 4183.611	272	.047	325.224	0	11.371	.078	.069	0	336.789
1983	703.182 4185.611	116	.375	319.185	.085	0	0	0	0	319.645
1983	703.182 4183.611	155	4.768	384.944	0	0	0	0	0	389.712
1983	703.182 4184.611	204	.531	341.799	.081	0	0	0	0	342.411
1984	701.228 4185.348	359	0	349.949	.262	0	0	0	.583	350.795
1984	701.499 4185.107	348	0	355.929	.129	0	0	0	0	356.059
1984	699.932 4183.611	204	.119	355.016	0	1.062	.189	.012	0	356.399
1984	698.182 4182.611	204	2.553	384.252	0	1.814	.440	.047	0	389.106
1985	701.228 4185.348	132	0	327.932	.048	0	0	0	0	327.981
1985	699.932 4183.611	178	.030	324.291	0	2.660	.403	.509	0	327.894
1985	699.182 4182.611	119	1.700	349.187	0	2.078	.510	.052	0	353.527
1986	701.228 4185.348	302	.033	342.012	.001	0	0	0	0	342.046

TABLE 5-14 - Continued

YEAR	UTM RECEPTOR (km)	DAY	8 TURBINES (42.67 m)	EW BROWN	PHILLIPS	EAST KY POWER	U OF K	IBM	KU TYRONE	ALL
1986	700.472 4183.880	356	.014	337.335	0	.469	.022	.292	0	338.132
1986	700.326 4183.995	204	.014	347.424	0	.066	.217	.119	0	347.839
1986	700.739 4185.246	264	.004	335.092	.030	.532	.094	.169	.001	335.922
1986	700.399 4183.937	203	1.611	340.868	0	.358	.609	.179	0	343.625
1986	700.311 4184.063	291	0	344.138	0	3.284	.002	0	0	347.424
1986	699.932 4183.611	204	.443	380.585	0	.072	.225	.121	0	381.445
1986	698.182 4182.611	204	3.846	308.974	0	.080	.318	.144	0	313.362
1986	703.182 4184.611	150	1.787	314.944	.085	0	0	0	0	316.815
1987	700.472 4183.880	80	.004	350.335	0	1.534	1.097	.973	.159	354.102
1987	700.326 4183.995	81	0	314.400	.002	.458	.161	.298	0	315.319
1987	700.544 4183.822	136	0	378.195	0	2.316	.086	.068	0	380.666

[d:\...\job\11927005\ku0603-t.514]

TABLE 5-15

CULPABILITIES ON NAAQS 24-HOUR HIGHEST, SECOND-HIGHEST DAY/RECEPTOR VIOLATIONS FOR SO_2

VENDOR 3

YEAR	UTM RECEPTOR (km)	DAY	7 TURBINES (60.96m)	EW BROWN	PHILLIPS	EAST KY POWER	U OF K	IBM	KU TYRONE	ALL
1983	701.403 4185.104	148	0	325.712	.004	0	0	0	0	325.716
1983	701.228 4185.348	247	0	351.119	.028	0	0	0	0	351.147
1983	700.399 4183.937	272	.003	301.981	0	11.309	.080	.066	0	313.437
1983	700.824 4185.247	318	0	357.299	0	0	0	0	0	357.299
1983	700.182 4184.111	19	.005	311.823	0	6.350	.450	.001	0	318.629
1983	699.932 4183.611	272	.056	325.224	0	11.371	.078	.069	0	336.798
1983	703.182 4185.611	116	.358	319.185	.085	0	0	0	0	319.628
1983	703.182 4183.611	155	4.957	384.944	0	0	0	0	0	389.901
1983	703.182 4184.611	204	1.359	341.799	.081	0	0	0	0	343.240
1984	701.228 4185.348	359	0	349.949	.262	0	0	0	.583	350.795
1984	701.499 4185.107	348	0	355.929	.129	0	0	0	0	356.059
1984	699.932 4183.611	204	.111	355.016	0	1.062	.189	.012	0	356.391
1984	698.182 4182.611	204	2.795	384.252	0	1.814	.440	.047	0	389.348
1985	701.228 4185.348	132	0	327.932	.048	0	0	0	0	327.981
1985	699.932 4183.611	178	.044	324.291	0	2.660	.403	.509	0	327.908
1985	699.182 4182.611	119	1.513	349.187	0	2.078	.510	.052	0	353.340
1986	701.228 4185.348	302	.002	342.012	.001	0	0	0	0	342.015
1986	700.472 4183.880	356	.002	337.335	0	.469	.022	.292	0	338.120
1986	700.326 4183.995	204	.024	347.424	0	.066	.217	.119	0	347.849
1986	700.739 4185.246	264	0	335.092	.030	.532	.094	.169	.001	335.918

TABLE 5-15 - Continued

YEAR	UTM RECEPTOR (km)	DAY	7 TURBINES (60.96m)	EW BROWN	PHILLIPS	EAST KY POWER	U OF K	IBM	KU TYRONE	ALL
1986	700.399 4183.937	203	1.159	340.868	0	.358	.609	.179	0	343.172
1986	700.311 4184.063	291	0	344.138	0	3.284	.002	0	0	347.424
1986	699.932 4183.611	204	.586	380.585	0	.072	.225	.121	0	381.588
1986	698.182 4182.611	204	3.266	308.974	0	.080	.318	.144	0	312.781
1986	703.182 4184.611	150	4.992	314.944	.085	0	0	0	0	320.020
1987	700.472 4183.880	80	.008	350.335	0	1.534	1.097	.973	.159	354.107
1987	700.326 4183.995	81	0	314.400	.002	.458	.161	.298	0	315.319
1987	700.544 4183.822	136	0	378.195	0	2.316	.086	.068	0	380.666

[d:\...\job\11927005\kent0514.vn3]

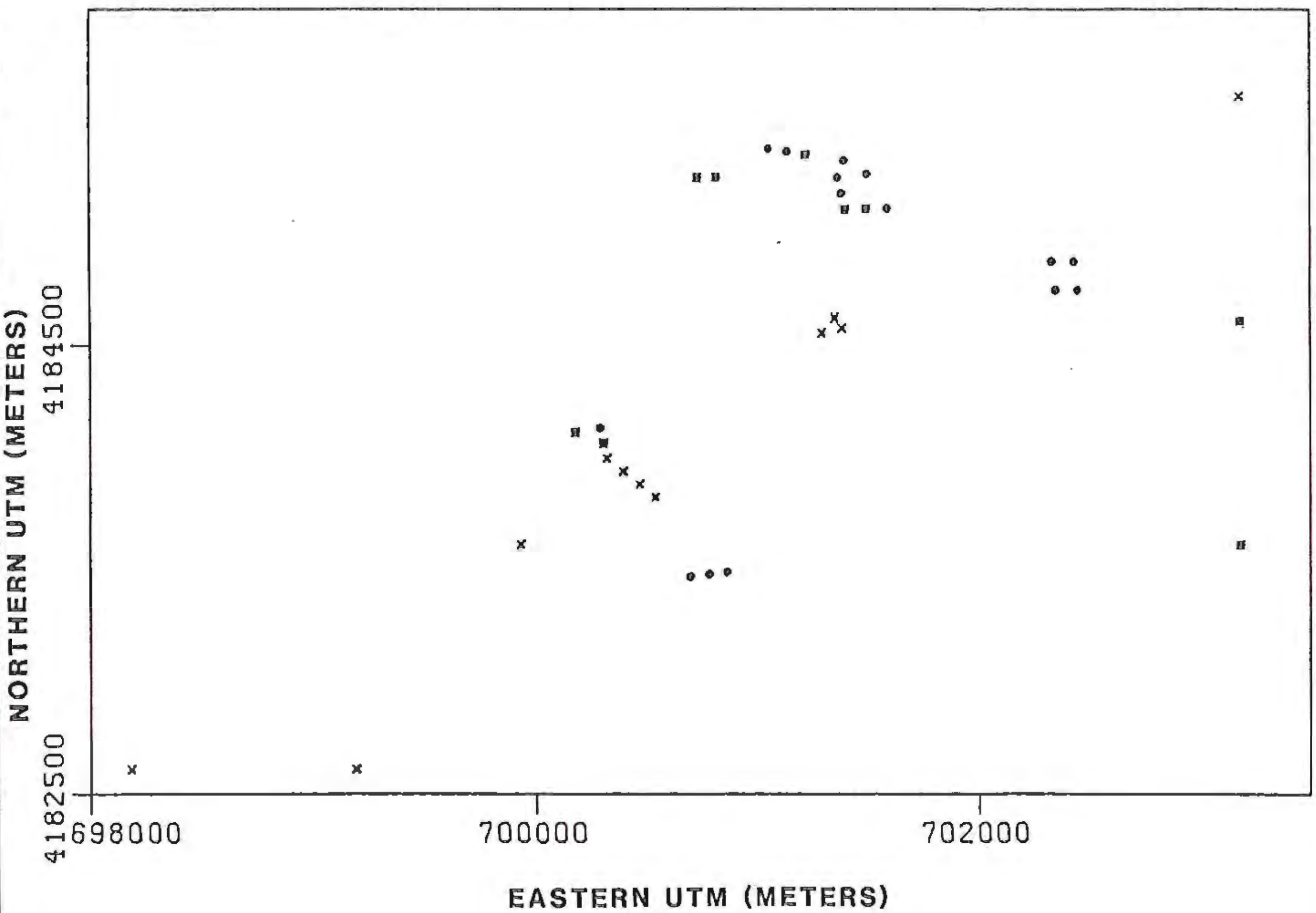


FIGURE 5-1
LOCATION OF PREDICTED
SO_2 EXCEEDANCES

wind-direction-dependent building dimensions for only sources having stack height to building height ratios of 1.5 and less. As can be seen from Table 5-16, this may lead to lower predicted concentrations for wind directions in which the height of the influencing building is at 45.42 meters for Unit 1 and/or 47.87 meters for Unit 2. For these directions the stack height for Units 1 and 2 are basically at GEP height and will result in lower predicted ground level concentrations.

b) Increase the stack height up to GEP stack height.

c) Revise SIP limitations.

d) Some combination of the above.

5.4 PSD AMBIENT AIR QUALITY MONITORING REQUIREMENT

One year of preconstruction ambient air quality monitoring may be required as part of PSD review. An applicant is exempt from this requirement if the impact of the proposed sources is less than monitoring de minimis concentrations. As indicated in Table 5-17 the maximum impact of the proposed turbines is less than the monitoring de minimis concentrations for SO_2, NO_x, TSP/PM_{10}, and CO, thus exempting KU from this requirement.

The maximum potential emissions of VOCs from the proposed turbines exceeds the PSD significant emission rate of 100 tons per year for one vendor. However, there are two O_3 monitors located in Fayette County, which are about 30 kilometers north-northeast of the E. W. Brown Station site. These monitors are considered representative of the ozone formation from the proposed station modification for the following reasons:

1. The monitors are located 30 km from the station. Ozone is considered a regional problem and, as such, the monitors are located within the regional influence of the proposed station modification.

2. If ozone monitors were to be required, they would be sited 12-18 km downwind of the proposed station modification and this location would be near the existing monitors.

TABLE 5-16

WIND-DIRECTION DEPENDENT BUILDING DIMENSIONS FOR E. W. BROWN UNITS 1 AND 2

WIND DIRECTION	UNIT 1		UNIT 2	
	HEIGHT (m)	WIDTH (m)	HEIGHT (m)	WIDTH (m)
10	45.42	97.65	47.87	55.72
20	45.42	99.76	67.36	52.98
30	45.42	100.12	67.36	55.23
40	45.42	99.55	67.36	55.81
50	45.42	96.19	67.36	55.75
60	45.42	89.91	67.36	54.46
70	45.42	80.89	67.36	51.50
80	47.87	47.13	67.36	46.98
90	67.36	41.69	67.36	41.69
100	67.36	47.50	67.36	47.50
110	67.36	51.87	67.36	51.87
120	67.36	54.66	67.36	54.66
130	67.36	55.79	67.36	55.79
140	67.36	55.81	67.36	55.81
150	67.36	55.08	67.36	55.08
160	47.87	70.41	47.87	70.41
170	45.42	92.99	47.87	65.66
180	45.42	94.74	47.87	58.91
190	45.42	97.65	47.87	55.72
200	45.42	99.76	67.36	52.98
210	45.42	100.12	67.36	55.23
220	45.42	99.55	67.36	55.81
230	45.42	96.19	67.36	55.75

TABLE 5-16 - Continued

WIND DIRECTION	UNIT 1		UNIT 2	
	HEIGHT (m)	WIDTH (m)	HEIGHT (m)	WIDTH (m)
240	45.42	89.91	67.36	54.46
250	45.42	80.89	67.36	51.50
260	47.87	47.13	67.36	46.98
270	67.36	41.69	67.36	41.69
280	67.36	47.50	67.36	47.50
290	67.36	51.87	67.36	51.87
300	67.36	54.66	67.36	54.66
310	67.36	55.79	67.36	55.79
320	67.36	55.81	67.36	55.81
330	67.36	55.08	67.36	55.08
340	47.87	70.41	47.87	70.41
350	45.42	92.99	47.87	65.66
360	45.42	94.74	47.87	58.91

[d:...\job\11927005\ku0603-t.516]

TABLE 5-17

COMPARISON OF MAXIMUM PREDICTED CONCENTRATIONS DUE TO THE PROPOSED MODIFICATION WITH MONITORING DE MINIMIS CONCENTRATIONS

POLLUTANT	TURBINE VENDOR	AVERAGING PERIOD	PREDICTED CONCENTRATION ($\mu g/m^3$) ISCST	PREDICTED CONCENTRATION ($\mu g/m^3$) COMPLEX I	MONITORING DE MINIMIS CONCENTRATION ($\mu g/m^3$)
SO_2	Vendor 1 Vendor 2 Vendor 3	24-Hour	10.1 12.0 7.8	10.7 12.7 9.1	13
NO_2	Vendor 1 Vendor 2 Vendor 3	Annual	0.21 0.14 0.14	0.26 0.20 0.20	14
CO	Vendor 1 Vendor 2 Vendor 3	8-Hour	4.4 5.3 1.9	2.4 2.8 1.0	575
TSP/PM_{10}	Vendor 1 Vendor 2 Vendor 3	24-Hour	0.5 1.9 0.9	0.5 2.0 1.1	10

[d:\...\job\11927005\ku0603-t.517]

3. The existing monitors are currently being used to determine if Fayette County and the metropolitan statistical area is in attainment, suggesting representativeness for Mercer County, which is contiguous to this area.

6.0 ADDITIONAL IMPACT ANALYSES

Analyses of the impact of emissions of the proposed turbines associated with construction and related growth, soil, vegetation, and visibility are presented in this section. A qualitative approach to these analyses was necessary for those areas in which analytical techniques are not well established. Compliance with Kentucky's air toxic pollutant regulations is also presented in this section.

6.1 CONSTRUCTION AND GROWTH IMPACTS

Construction impacts on air quality will consist mainly of the relatively minor amounts of pollutants emitted from construction equipment required for site preparation and from fugitive dust emissions. General construction vehicles (both gasoline- and diesel-powered) and other diesel-powered engines will be used. These engines emit minor amounts of VOCs, SO_2, CO, NO_2, and PM. The contaminants are expected to cause localized, temporary increases in existing air quality levels, but are not expected to cause any adverse impacts on or beyond the site boundary. These vehicles will be operated only for a portion of a day during construction. Fugitive dust emissions will probably be the most noticeable impact during construction. Dust will be associated with ground excavation, cut-and-fill operations, and other activities. The amount of dust will vary from day to day, depending on the level of activity and the weather. PM concentrations beyond the E. W. Brown Station boundary, due to fugitive dust from construction activities, should not occur. Various control techniques will be taken to prevent PM from becoming airborne.

The construction and operation will result in minor growth in the area.

6.2 IMPACT ON SOIL AND VEGETATION

The secondary NAAQS are intended to protect the public welfare from adverse effects of airborne effluents. This protection extends to agricultural soil. As demonstrated in Section 5.0, predicted pollutant concentrations throughout the study area will be below the secondary NAAQS prior to the operation of the proposed turbines. Since the secondary NAAQS protect impact on human welfare, no significant adverse impact on soil is anticipated due to the proposed modification.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas, long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

SO_2 enters the plant primarily through the leaf stomata and passes into the intercellular spaces of the mesophyll, where it is absorbed on the moist cell walls and combined with water to form sulfurous acid and sulfite salts. Plant species show a considerable range of sensitivity to SO_2. This range is the result of complex interactions among microclimatic (temperature, humidity, light, etc.) edaphic, phenological, morphological, and genetic factors that influence plant response (USEPA, 1973).

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. Acute and chronic threshold injury levels for NO_2 are much higher than those for SO_2 (USEPA, 1971).

The maximum predicted ambient concentrations due to the proposed station modification in combination with the compliance strategy for the E. W. Brown station will result in concentrations below the ambient air quality standards, thus, there will be no adverse effects on vegetation.

6.3 IMPACT ON VISIBILITY

Any facility emitting significant amounts of SO_2, PM, and/or NO_x has a potential adverse impact on visibility through atmospheric discoloration or reduction of visual range due to increased haze. The Clean Air Act requires an evaluation of visibility impairment in the vicinity of PSD Class I areas due to emissions from new or modified air pollution sources. The expected visibility impact from the proposed combustion turbines was assessed using the USEPA document, "Workbook for Plume Visual Impact Screening and Analysis" (USEPA, 1988) worst-case. TSP and NO_x emissions of 668.0 and 2485.0 tons per year, respectively, were input to the VISCREEN Model for performing a Level I Visibility Screening Analysis. Visibility impact of these emissions was evaluated at the nearest portion of the Mammoth Cave National Park, 129 km southwest of Kentucky Utilities' proposed sources.

Results of the Level I screening analysis, presented in Table 6-1, indicate that the visibility impact of the proposed sources is below both the threshold level of 0.05 for plume contrast and 2.0 for delta E. These results apply for impacts inside and outside the Class I area. Therefore, it can be concluded that there will not be an adverse impact on visibility at the Mammoth Cave National Park due to the proposed emissions.

6.4 TOXIC AIR POLLUTANT ASSESSMENT

The relationship of the proposed modification to Kentucky's air toxic pollutant regulations was evaluated. Emissions of TAPs may result during the combustion of natural gas and distillate oil. However, indirect heat exchangers using fossil fuels are exempt from these regulations. As a result, no further analyses were warranted.

TABLE 6-1

Visual Effects Screening Analysis for
Source: KENTUCKY UTILITIES
Class I Area: MAMMOUTH CAVE N.P.

*** Level-1 Screening ***

Input Emissions for

Particulates	668.00	TON/YR
NOx (as NO2)	2485.00	TON/YR
Primary NO2	.00	TON/YR
Soot	.00	TON/YR
Primary SO4	.00	TON/YR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	129.00 km
Min. Source-Class I Distance:	129.00 km
Max. Source-Class I Distance:	148.00 km
Plume-Source-Observer Angle:	11.25 degrees

Stability: 6
Wind Speed: 1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	129.0	84.	2.00	.044	.05	.000
SKY	140.	84.	129.0	84.	2.00	.008	.05	-.000
TERRAIN	10.	84.	129.0	84.	2.00	.002	.05	.000
TERRAIN	140.	84.	129.0	84.	2.00	.000	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	124.9	94.	2.00	.046	.05	.000
SKY	140.	75.	124.9	94.	2.00	.009	.05	-.000
TERRAIN	10.	65.	120.4	104.	2.00	.002	.05	.000
TERRAIN	140.	65.	120.4	104.	2.00	.001	.05	.000

7.0 REFERENCES

Auer, A. H. (1978): "Correlation of Land Use and Cover with Meteorological Anomalies," Journal of Applied Meteorology, Volume 17, pp. 636-643.

Briggs, G. A. (1971): "Some Recent Analyses of Plume Rise Observations," Proceedings of the Second International Clean Air Congress, Edited by Englund, H. M., and Berry, W. T., Academic Press, pp. 1029-1032.

____ (1973): "Diffusion Estimation for Small Emissions," ATDL Contribution No. 79 (Draft), Air Resources, Atmospheric Turbulance and Diffusion Laboratory, NOAA, Oak Ridge, Tennessee.

____ (1975): "Plume Rise Predictions," Lectures on Air Pollution and Environmental Impact Analysis, American Meteorological Society, Boston, Massachussets.

Burt, E. (1977): "VALLEY Model User's Guide," EPA-450/2-77-018, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina (September).

Huber, A., and Snyder, A. (1976): "Building Wake Effects on Short Stack Effluents," Preprints of the American Meteorological Society Third Symposium on Atmospheric Turbulence, Diffusion, and Air Quality, Raleigh, North Carolina.

Huber, A. (1977): "Incorporating Building/Terrain Wake Effects on Stack Effluents," Preprints of the American Meteorological Society - Air Pollution Control Association Joint Conference on Applications of Air Pollution Meteorology, Salk Lake City, Utah (November).

Irwin, J. S. (1979): "Proposed Criteria for Selection of Urban Versus Rural Dispersion Coefficients," Meteorology and Assessment Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

Schulman, L. L.; S. R. Hanna; and D. W. Heinold (1985): "Evaluation of Proposed Downwash Modifications to the Industrial Source Complex Model," Environmental Research and Technology, Inc., P-B810-012, January 1985.

Schulman, L. L. and S. R. Hanna (1986): "Evaluation of Downwash Modifications to the Industrial Source Complex Model," J. Air Pollution Control Association 36(3), 258-264.

Schulman, L. L. and J. S. Scire (1980a): "Buoyant Line and Point Source (BLP) Dispersion Model User's Guide. Document P073048, Environmental Research and Technology, Inc., Concord, MA.

Scire, J. S., and L. L. Schulman (1980b): "Modeling Plume Rise from Low-Level Buoyant Line and Point Sources," Proceedings Second Joint Conference on Applications of Air Pollution Meteorology, 24-28 March, New Orleans, LA, 133-139.

Turner, D. B. (1970): "Workbook of Atmospheric Dispersion Estimates," AP-26, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

Turner, D. B. and Novak, J. H. (1978): "User's Guide for RAM, Volume I - Algorithm Description and Use," EPA-600/8-78-016a, Environmental Sciences Research Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

U.S. Environmental Protection Agency (1971): "Air Quality Criteria for Nitrogen Oxides," AP-84, Air Pollution Control Office, Washington, D.C.

____ (1973): "Air Quality Criteria for Sulfur Oxides," EPA-R3-73-030, National Environmental Research Center, Research Triangle Park, North Carolina.

____ (1974): "Applying Atmospheric Simulation Models to Air Quality Maintenance Area," Guidelines for Air Quality Maintenance Planning and Analysis 12, Publication No. OAQPS 1.2-031, EPA-450/4-74-013.

____ (1985a): "Guideline for Determination of Good Engineering Practice Stack Height" (Technical Support Document for the Stack Height Regulations). EPA-450/4-80-023LR. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

____ (1985b, 1990): "BACT/LAER Clearinghouse - A Compilation of Control Technology Determinations,"Research Triangle Park, North Carolina.

____ (1986): "Guidelines on Air Quality Models-Revised," EPA-450/2-78-027R, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

____ (1987): "Industrial Source Complex Dispersion Model User's Guide," Volume 1, EPA-450/4-79-030, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

____ (1988): "Wookbook for Plume Visual Impact Screening and Analysis," EPA-450/4-88-015, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

[d:\...\job\11927005\kent0429.haw]

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

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

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

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
Arsenic[d]	< 1.1 E-05	D
Beryllium[d]	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel[d]	< 4.6 E-06	D
Selenium[d]	< 2.5 E-05	D

[a] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.
[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".
[c] Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.
[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.

EMISSION FACTOR DOCUMENTATION FOR AP-42 SECTION 3.1 STATIONARY GAS TURBINES

Prepared for:

Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC

Prepared by:

Alpha-Gamma Technologies, Inc.
4700 Falls of Neuse Road
Raleigh, North Carolina

April 2000

$$\text{Temperature correction (to 68°F)} = \left(\frac{528°R}{460°R_1 + T_{std}\ °F} \right)$$

$$\text{Oxygen correction (to 0\% } O_2) = \left(\frac{20.9}{20.9 - \%O_2} \right)$$

The emission factors are based on gas turbines operating on both gaseous and liquid fuels. For consistency in comparing control options, the emission factors are presented in units of lb/MMBtu. A method to convert units from lb/MMBtu to lb/MMscf for natural gas-fired, landfill gas-fired, and digester gas-fired gas turbines is provided below. Also, a method of conversion is provided to obtain lb/1,000 gallons for distillate fired gas turbines.

For gas turbines that burn natural gas, the conversion of lb/MMBtu to lb/10^6 scf can be made using an assumed natural gas heating value of 1020 MMBtu/10^6 scf. This conversion can be done through the following equation:

$$\text{lb}/10^6 \text{ scf} = \text{lb/MMBtu} * 1020 \text{ (MMBtu}/10^6 \text{ scf)}$$

For gas turbines that burn landfill gas, the conversion of lb/MMBtu to lb/10^6 scf can be made using an assumed natural gas heating value of 400 MMBtu/10^6 scf. This conversion can be done through the following equation:

$$\text{lb}/10^6 \text{ scf} = \text{lb/MMBtu} * 400 \text{ (MMBtu}/10^6 \text{ scf)}$$

For gas turbines that burn digester gas, the conversion of lb/MMBtu to lb/10^6 scf can be made using an assumed natural gas heating value of 600 MMBtu/10^6 scf. This conversion can be done through the following equation:

$$\text{lb}/10^6 \text{ scf} = \text{lb/MMBtu} * 600 \text{ (MMBtu}/10^6 \text{ scf)}$$

For gas turbines that burn distillate oil, the conversion of lb/MMBtu to lb/10^3 gallons can be made using an assumed distillate oil heating value of 139 MMBtu/10^3 gallon. This conversion can be done through the following equation:

$$\text{lb}/10^3 \text{ gallon} = \text{lb/MMBtu} * 139 \text{ (MMBtu}/10^3 \text{ gallon)}$$

<u>Detection Limits</u>

For cases where the concentration of a specific pollutant was below the test method detection limit and a detection limit was provided, then half of the detection limit was used to calculate an emission factor. If no detection limit was provided, then the results from that test were not used. Furthermore, if an emission factor for an individual engine was developed from a detection limit and the resulting emission factor was higher than the emission factors generated from detected concentrations, then the emission factor based on a detection limit was removed from the average. The goal of this decision was to prevent unusually high detection limits from artificially increasing an average emission factor. If an average emission factor was generated entirely from detection limits and not on measured values, it is noted as an emission factor based on detection limits and that expected emissions are lower than the emission factor. These methods for addressing detection level issues were provided in the Procedures For Preparing Emission Factor Documents.[1]

Calculation of Average Emission Factors

To provide average emission factors for these sources, the emission factors from all tests in a specific group were averaged to generate an emission factor. The averaging method used in the data base was an arithmetic average. For tests that consisted of multiple runs, the arithmetic average of the runs was used to develop the emission factor of that test. Individual tests were given equal weight in the calculation of average emission factors for each turbine group. If the majority of data used to generate an emission factor were from non-detect results where the detection limit was used, then the average emission factor was noted to be made up of mostly detection limit estimates. The EPA intends for average emission factors generated from mostly detection levels to provide order of magnitude estimates of emissions levels, and these data are given a low quality rating.

Presentation of Data

Due to the size of the data base, a printout of all the test data used to generate the engine emission factors in Section 3.1 is not presented. Instead, EPA is providing an electronic copy of the data base in Microsoft Access format on the Technology Transfer Network (TTN). This decision has resulted in a substantial decrease in paper needed for this background information document and will provide users with a more detailed background data set for this section. Furthermore, by providing the data base to the public, anyone may use or augment the data base for their individual needs, providing a substantial building block for anyone interested in compiling an extensive data base on natural gas-fired combustion sources. An electronic copy of the data base can be downloaded from the TTN at http://www.epa.gov/ttn/chief. In this website, follow the main menu options to locate the file and then download it.

To view the tests used to calculate the emission factors calculated for theses sources, open the data base file which will automatically open the MAIN FORM view (in cases where the MAIN FORM does not open, open the file and choose the FORMS selection on the main data base screen, then under the FORMS selection, choose MAIN FORM). This will activate a macro which will provide a pollutant list, fuel type, and control device type available for these sources. This provides the option to view the input data, source information, or the emission tests used to calculate the emission factor for a specific pollutant (based on fuel type and control information) by simply clicking on the desired button: To view the data used to calculate the average emission factor for each test, click the EF INPUTS button; to view the individual source information, click the VIEW FACILITIES button; to view the data used for calculating the emission factor, click the EF REPORT button.

To view the tests that were not used to determine the emission factors, close the MAIN FORM and select the Report Menu. Under the Report Menu, select the "Report for not used tests". This report provides a brief summary of the test information, fuel type, and the corresponding emissions.

different emissions tests.

C-Rated Emission factor average based on results of A or B-rated data from three to nine different emissions tests.

D-Rated Emission factor average based on results of A or B-rated data from two or less emissions tests.

E-Rated Emission factor average based on engineering judgement or tests rated at C or below.

3.4 Emission Factors

The emission factors for the sources covered in Section 3.1 of the AP-42 document are presented in Tables 3.4-1, 3.4-2, 3.4-3, and 3.4-4. These tables provide the number of tests used in calculating the various emission factors as well as the relative standard deviation (in percent) associated with each emission factor. This additional information is intended to provide greater insight to the reader about the background of each emission factor. For further detail on each emission factor, the complete data base used to generate these factors is provided on the web at "www.epa.gov/ttn/chief" (See Section 3.2.1 of this document for more details on the data base).

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR NATURAL GAS-FIRED GAS TURBINES

Natural Gas-Fired Gas Turbine HAP Emissions

			All Loads				**High Loads: Greater Than or Equal to 80 Percent**			
Pollutant	CAS No.	Control Method	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
1,3-Butadiene	106-99-0	Uncontrolled	< 4.29 E-07	< 4.38 E-04	121.5	2	< 4.29 E-07	< 4.38 E-04	121.5	2
Acetaldehyde	75-07-0	Uncontrolled	4.45 E-05	4.54 E-02	64.3	9	4.02 E-05	4.10 E-02	68.0	8
Acetaldehyde	75-07-0	CO Catalyst	1.76 E-04	1.80 E-01	139.5	2	1.76 E-04	1.80 E-01	139.5	2
Acrolein	107-02-8	Uncontrolled	8.31 E-06	8.48 E-03	71.5	7	6.36 E-06	6.49 E-03	50.9	6
Acrolein	107-02-8	CO Catalyst	3.62 E-06	3.69 E-03	NA	1	3.62 E-06	3.69 E-03	NA	1
Benzene	71-43-2	Uncontrolled	1.03 E-04	1.05 E-01	440.0	27	1.18 E-05	1.20 E-02	136.1	17
Benzene	71-43-2	CO Catalyst	3.26 E-06	3.33 E-03	101.9	2	3.26 E-06	3.33 E-03	101.9	2
Ethylbenzene	100-41-4	Uncontrolled	2.58 E-05	2.63 E-02	130.4	5	3.20 E-05	3.27 E-02	110.2	4
Formaldehyde	50-00-0	Uncontrolled	3.12 E-03	3.18 E+00	204.0	33	7.09 E-04	7.23 E-01	206.1	22
Formaldehyde	50-00-0	CO Catalyst	3.60 E-04	3.67 E-01	133.5	2	3.60 E-04	3.67 E-01	133.5	2
Naphthalene	91-20-3	Uncontrolled	1.37 E-06	1.40 E-03	87.6	5	1.27 E-06	1.30 E-03	107.3	4
PAH	NA	Uncontrolled	2.25 E-06	2.30 E-03	131.1	5	2.23 E-06	2.27 E-03	152.9	4
Propylene Oxide	75-56-9	Uncontrolled	< 2.86 E-05	< 2.92 E-03	NA	1	< 2.86 E-05	< 2.92 E-03	NA	1
Toluene	108-88-3	Uncontrolled	9.37 E-05	9.56 E-02	220.6	11	1.34 E-04	1.37 E-01	191.0	7
Xylenes	1330-20-7	Uncontrolled	5.48 E-05	5.59 E-02	108.1	7	6.38 E-05	6.50 E-02	93.2	6

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR NATURAL GAS-FIRED GAS TURBINES
(Continued)

Natural Gas-Fired Gas Turbine Criteria Emissions

		All Loads				High Loads: Greater Than or Equal to 80 Percent			
Pollutant	Control Method	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
CO	Uncontrolled	1.77 E-01	1.80 E+02	267.5	76	8.23 E-02	8.39 E+01	171.4	53
CO	Water-Steam Injection	3.34 E-02	3.41 E+01	106.3	18	2.95 E-02	3.01 E+01	117.0	16
CO	Lean Pre-Mix	1.27 E+00	1.30 E+03	189.5	4	1.51 E-02	1.54 E+01	NA	1
Methane	Uncontrolled	8.64 E-03	8.81 E+00	142.2	5	8.64 E-03	8.81 E+00	142.2	5
NO_X	Uncontrolled	2.95 E-01	3.01 E+02	75.0	80	3.23 E-01	3.29 E+02	69.8	56
NO_X	Water-Steam Injection	1.26 E-01	1.28 E+02	29.8	75	1.28 E-01	1.30 E+02	29.8	46
NO_X	Lean Pre-Mix	1.11 E-01	1.13 E+02	23.6	4	9.91 E-02	1.01 E+02	NA	1
NO_X	SCR	1.28 E-02	1.31 E+01	13.1	4	1.28 E-02	1.31 E+01	13.1	4
PM Condensable	Water-Steam Injection	4.73 E-03	4.82 E+00	90.9	1	4.73 E-03	4.82 E+00	90.9	1
PM Filterable	Water-Steam Injection	1.90 E-03	1.93 E+00	49.5	1	1.90 E-03	1.93 E+00	49.5	1

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR NATURAL GAS-FIRED GAS TURBINES (Concluded)

Natural Gas-Fired Turbine Criteria Emissions

		All Loads				**High Loads: Greater Than or Equal to 80 Percent**			
Pollutant	Control Method	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMscf)	RSD Percent	Count
PM total[a]	Water-Steam Injection	6.63 E-03	6.76 E+00	NA	1	6.63 E-03	6.76 E+00	NA	1
SO_2	Uncontrolled	3.38 E-03	3.45 E+00	45.5	6	3.38 E-03	3.45 E+00	45.5	6
TOC[b]	Uncontrolled	1.07 E-02	1.09 E+01	141.1	10	1.07 E-02	1.09 E+01	141.1	10
VOC[c]	Uncontrolled	2.06 E-03	2.09 E+00	NA	5	2.06 E-03	2.09 E+00	NA	5

[a] Calculated value: PM total = PM (condensable) + PM (filterable).
[b] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.
[c] Calculated value: VOC = THC - Methane.

Table 3.4-2. SUMMARY OF EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES

Distillate Oil-Fired Gas Turbines HAP Emissions

			All Loads				High Loads: Greater Than or Equal to 80 Percent			
Pollutant	CAS No.	Control Method	Emission Factor		RSD Percent	Count	Emission Factor		RSD Percent	Count
			(Lb/MMBtu)	(lb/1,000 gal)			(Lb/MMBtu)	(lb/1,000 gal)		
1,3-Butadiene	106-99-0	Uncontrolled	< 1.65 E-05	< 2.30 E-03	47.5	4	< 1.58 E-05	< 2.20 E-03	NA	1
1,4-Dichlorobenzene	106-46-7	Uncontrolled	< 2.97 E-05	< 4.12 E-03	5.8	3	NA	NA	NA	NA
Acetaldehyde	75-07-0	Uncontrolled	3.03 E-05	4.21 E-03	36.9	2	NA	NA	NA	NA
Arsenic	NA	Uncontrolled	< 1.10 E-05	< 1.53 E-03	72	4	< 1.06 E-05	< 1.47 E-03	NA	1
Benzene	71-43-2	Uncontrolled	5.48 E-05	7.62 E-03	104.9	5	5.48 E-05	7.62 E-03	104.9	5
Beryllium	NA	Uncontrolled	< 3.07 E-07	< 4.27 E-05	NA	1	< 3.07 E-07	< 4.27 E-05	NA	1
Cadmium	NA	Uncontrolled	3.75 E-06	5.21 E-04	78.3	4	4.80 E-06	6.67 E-04	NA	1
Carbon Tetrachloride	56-23-5	Uncontrolled	< 3.06 E-05	< 4.25 E-03	8.2	3	NA	NA	NA	NA
Chlorobenzene	108-90-7	Uncontrolled	< 2.49 E-05	< 3.46 E-03	10.2	3	NA	NA	NA	NA
Chloroform	67-66-3	Uncontrolled	< 2.55 E-05	< 3.55 E-03	4.4	3	NA	NA	NA	NA
Chromium	NA	Uncontrolled	8.43 E-06	1.17 E-03	64.6	5	1.08 E-05	1.51 E-03	8.5	2
Ethylene Dichloride	107-06-2	Uncontrolled	2.02 E-05	2.81 E-03	1.4	2	NA	NA	NA	NA
Formaldehyde	50-00-0	Uncontrolled	2.45 E-04	3.41 E-02	120.6	10	2.82 E-04	3.92 E-02	115.0	8
Lead	NA	Uncontrolled	1.34 E-05	1.87 E-03	50.6	5	1.42 E-05	1.97 E-03	51.2	2
Manganese	NA	Uncontrolled	7.89 E-04	1.10 E-01	NA	1	7.89 E-04	1.10 E-01	NA	1
Methylene Chloride	74-87-3	Uncontrolled	< 2.13 E-05	< 2.97 E-03	29.5	3	NA	NA	NA	NA
Mercury	NA	Uncontrolled	1.20 E-06	1.67 E-04	NA	1	1.20E-06	1.67E-04	NA	1
Naphthalene	91-20-3	Uncontrolled	3.52 E-05	4.89 E-03	187.9	5	3.52 E-05	4.89 E-03	187.9	5

Table 3.4-2. SUMMARY OF EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES (Concluded)

Distillate Oil-Fired Gas Turbines Criteria Emissions

		All Loads				High Loads: Greater Than or Equal to 80 Percent			
Pollutant	Fuel Source	Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count
CO	Uncontrolled	1.24 E-02	1.72 E+00	125.7	5	3.29 E-03	4.57 E-01	23.3	3
CO	Water-Steam Injection	1.03 E-01	1.43 E+01	44.1	8	7.61 E-02	1.05 E+01	43.2	5
NMHC	Uncontrolled	8.03 E-03	1.22 E+00	34.8	2	NA	NA	NA	NA
NO_X	Uncontrolled	6.37 E-01	8.85 E+01	55.1	6	8.82 E-01	1.23 E+02	36.0	3
NO_X	Water-Steam Injection	2.34 E-01	3.25 E+01	22.0	23	2.44 E-01	3.39 E+01	21.9	13
PM Condensable	Water-Steam Injection	7.18 E-03	9.98 E-01	NA	1	7.18 E-03	9.98 E-01	65.3	1
PM Filterable	Water-Steam Injection	4.32 E-03	6.00 E-01	NA	1	4.32 E-03	6.00 E-01	55.3	1
PM total[a]	Water-Steam Injection	1.15 E-02	1.60 E+00	NA	1	1.15 E-02	1.60 E+00	NA	1
PM-10	Uncontrolled	2.03 E-02	2.82 E+00	76.4	2	NA	NA	NA	NA
PM-10	Water-Steam Injection	4.40 E-02	6.12 E+00	141.4	2	4.40 E-02	6.12 E+00	141.4	2
SO_2	Uncontrolled	3.30 E-02	4.58 E+00	69.1	2	NA	NA	NA	NA
TOC[b]	Water-Steam injection	4.64 E-03	6.46 E-01	28.6	6	4.01 E-03	5.58 E-01	21.9	3

[a] Calculated value: PM (total) = PM (condensable) + PM (filterable)
[b] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

Table 3.4-2. SUMMARY OF EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES
(Continued)

Distillate Oil-Fired Gas Turbines HAP Emissions

			All Loads				**High Loads: Greater Than or Equal to 80 Percent**			
Pollutant	CAS No.	Control Method	Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count	Emission Factor (lb/MMBtu)	Emission Factor (lb/1,000 gal)	RSD Percent	Count
Nickel	NA	Uncontrolled	1.62 E-05	2.26 E-03	146.9	4	< 4.61 E-06	< 6.41 E-04	NA	1
PAH	NA	Uncontrolled	4.03 E-05	5.61 E-03	182.0	6	4.03 E-05	5.61 E-03	163.9	5
Selenium	NA	Uncontrolled	< 2.88 E-05	< 4.00 E-03	110.5	4	< 2.52 E-05	< 3.50 E-03	NA	1
Tetrachloroethylene	127-18-4	Uncontrolled	< 3.24 E-05	< 4.50 E-03	12.0	3	NA	NA	NA	NA
Trichloroethylene	79-01-6	Uncontrolled	< 2.75 E-05	< 3.82 E-03	1.0	3	NA	NA	NA	NA
Vinyl Chloride	75-01-4	Uncontrolled	< 5.27 E-05	< 7.33 E-03	40.5	3	NA	NA	NA	NA
Vinylidene Chloride	75-35-4	Uncontrolled	< 2.02 E-05	< 2.81 E-03	1.4	2	NA	NA	NA	NA

VENTURA COUNTY AIR POLLUTION CONTROL DISTRICT
669 County Square Drive, Ventura CA 93003 805/ 645-1401 FAX 805/ 645-1444 www.vcapcd.org

AB 2588 COMBUSTION EMISSION FACTORS

Emission factors for combustion of natural gas and diesel fuel were developed for use in AB 2588 emission inventory reports in 1990 and updated in 1991, 1992 and 1995. These factors have been updated again based on new data available from the USEPA (1) (10).

These emission factors are to be used where source testing or fuel analysis are not required by the AB 2588 Criteria and Guidelines Regulations, Appendix D. The factors are divided into external combustion sources (boilers, heaters, flares) and internal combustion sources (engines, turbines). Natural gas combustion factors are further divided into a number of sub-categories, based on equipment size and type.

If better source specific data such as manufacturer's data, source tests, or fuel analysis is available, it should be used rather than these emission factors.

Natural Gas Combustion Factors

Natural gas combustion factors were developed for listed substances identified by the California Air Resources Board (CARB) as significant components of natural gas combustion emissions (2) and for some federal HAPs.

In the past, the VCAPCD has included emission factors for natural gas fired internal combustion equipment in this document. In 2000, the USEPA published air toxics emission factors for natural gas fired turbines and engines. For natural gas fired internal combustion equipment, the emission factors from the USEPA publication AP-42 (1) should be used.

For natural gas fired turbines, emission factors from Table 3.1-3 of AP-42, dated April 2000 should be used. For natural gas fired internal combustion engines, emission factors from Tables 3.2-1, 3.2-2, and 3.2-3 of AP-42, dated August 2000, as applicable, should be used.

Natural Gas Fired External Combustion Equipment

	<10 MMBTUh	10-100 MMBTUh	>100 MMBTUh	flare
Pollutant	Emissions (lb/MMcf)			
benzene	0.0080	0.0058	0.0017	0.159
formaldehyde	0.0170	0.0123	0.0036	1.169
PAH's (including naphthalene)	0.0004	0.0004	0.0004	0.014
naphthalene	0.0003	0.0003	0.0003	0.011
acetaldehyde	0.0043	0.0031	0.0009	0.043
acrolein	0.0027	0.0027	0.0008	0.010
propylene	0.7310	0.5300	0.01553	2.440
toluene	0.0366	0.0265	0.0078	0.058
xylenes	0.0272	0.0197	0.0058	0.029
ethyl benzene	0.0095	0.0069	0.0020	1.444
hexane	0.0063	0.0046	0.0013	0.029

External combustion equipment includes boilers, heaters, and steam generators.

Derivation of Factors

The emission factors for boilers, heaters, and steam generators were based on the results of source tests performed mostly on units rated at between 10 and 100 million BTU per hour. The following test data was used: benzene (3) (6) (16) (19); formaldehyde (3) (6) (19); PAH, naphthalene, toluene, xylenes, ethyl benzene (16) (19); acetaldehyde, acrolein, and propylene (19); and hexane (20).

The test results listed above were used directly to determine the emission factors for boilers, heaters, and steam generators with heat input ratings of 10-100 MMBTU/hr. For units <10 MMBTU/hr and >100 MMBTU/hr, were calculated by scaling the factors for 10-100 MMBTU/hr equipment by the ratios of their TOC emission factors (7).

For flares, the factors were developed by applying the CARB species profiles (8) to the USEPA TOC emission factor for flares (1). The internal combustion species profile was used as CARB stated that they had very little confidence in the external combustion profile, and they use only the internal combustion profile (9). Information on acrolein was not contained in the species profile used. It was therefore assumed that the ratio of acrolein to formaldehyde is the same for flares as for turbines. The PAH emission factor is from EPA (10)

Diesel Combustion Factors

Diesel (#1, #2 fuel oil) combustion factors were developed for listed substances identified by the CARB as significant components of diesel fuel combustion emissions (2) and for federal HAPs for which data was available.

Diesel Combustion Factors

	external combustion	internal combustion
Pollutant	Emissions (lb/1000 gal)	
benzene	0.0044	0.1863
formaldehyde	0.3506	1.7261
PAH's (including naphthalene)	0.0498	0.0559
naphthalene	0.0053	0.0197
acetaldehyde	0.3506	0.7833
acrolein	0.3506	0.0339
1,3-butadiene	0.0148	0.2174
chlorobenzene	0.0002	0.0002
dioxins	ND	ND
furans	ND	ND
propylene	0.0100	0.4670
hexane	0.0035	0.0269
toluene	0.0044	0.1054
xylenes	0.0016	0.0424
ethyl benzene	0.0002	0.0109
hydrogen chloride	0.1863	0.1863
arsenic	0.0016	0.0016
beryllium	ND	ND
cadmium	0.0015	0.0015
total chromium	0.0006	0.0006
hexavalent chromium	0.0001	0.0001
copper	0.0041	0.0041
lead	0.0083	0.0083
manganese	0.0031	0.0031
mercury	0.0020	0.0020
nickel	0.0039	0.0039
selenium	0.0022	0.0022
zinc	0.0224	0.0224

ND - not detected

Derivation of Factors

For external combustion equipment, formaldehyde, PAH, and naphthalene emission factors for were developed using source test data (17). Based on information from CARB it was assumed that acetaldehyde and acrolein emissions would be the same as formaldehyde (14). Emission factors for toluene, xylenes, propylene, ethyl benzene, and hexane were based on USEPA emission factors for total organic compounds and CARB species profile (8) for substances identified by CARB as significant.

For internal combustion engines, emission factors for formaldehyde, PAH's, naphthalene, and metals were based on source testing (4), (5), (6), (18). Benzene, acetaldehyde, acrolein, toluene and xylenes emission factors were based on sources (4), (5), and (18). Propylene factors were based on source tests (4) and (5). 1,3-butadiene was based on (4). Ethyl benzene and hexane emission factors were based on (18).

For all oil combustion equipment, emission factors for chlorobenzene, hydrogen chloride, and metals were based on stack testing and fuel analyses (4), (5), (6), (12), (13), (18). It was assumed that 99.9% of the chlorine contained in the fuel was converted to hydrogen chloride (15), with the remainder converted to chlorobenzene. 5% of the chromium in the fuel samples was assumed to be emitted as hexavalent chromium (15).

Dioxins (PCDD's), furans (PCDF's), and beryllium were identified as potentially significant components of diesel combustion exhaust (2). However, the only test results for diesel combustion found (11) reported "not detected" for dioxins and furans. Beryllium has not been detected in any of the diesel fuel analyses reviewed (4), (5), (6), (12), (13), (18). For emission inventory reporting purposes, facilities should report these compounds on for PRO using an emission estimation code of "99" and writing "ND" for the emissions.

References

(1) USEPA, Compilation of Air Pollutant Emission Factors, Volume I, Fifth Edition, AP-42, January 1995, and Supplement F, 2000

(2) Gary Agid, California Air Resources Board, Letter to Air Pollution Control District, September 12, 1989

(3) CARNOT, Emission Inventory Testing at Southern California Edison Company Long Beach Auxiliary Boiler, May 1990

(4) CARNOT, Emissions of Air Toxic Species: Test Conducted Under AB 2588 for the Western States Petroleum Association, May 1990

(5) South Coast Environmental, Compliance Report: Hydraulic Dredge "Ollie Riedel", Report Number T1238C, March 8, 1991

(6) ENSR Consulting and Engineering, Western States Petroleum Association, Pooled Source Report: Oil and Gas Production Combustion Sources, Fresno and Ventura Counties, California, Document Number 7230-007-700, January 1991

(7) Ventura County Air Pollution Control District, Emission Factors and Calculation Procedures, July 1985

(8) State of California Air Resources Board, Identification of Volatile Organic Compound Species Profiles, August 1991, as updated November 29, 2000, profiles 504 and 719

(9) Paul Allen, California Air Resources Board, Telephone conversation, February 1, 1990

(10) United States Environmental Protection Agency, Locating and Estimating Air Emissions From Sources of Polycyclic Organic Matter, EPA-454/R-98-014, July 1998

(11) United States Environmental Protection Agency, Toxic Air Pollutant Emission Factors-A Compilation for Selected Air Toxic Compounds and Sources, EPA-450/2-88-006a, October 1988

(12) BTC Environmental, Inc., Ventura Port District Dredge: Air Toxics Emissions Retesting, January 29, 1991

(13) Shell Western E & P, Emission Inventory Report for Ventura Avenue Field, June 11, 1990

(14) Muriel Strand, California Air Resources Board, Telephone conversation, February 6, 1990

(15) State of California Air Resources Board, Technical Guidance Document to the Criteria and Guidelines Regulation for AB 2588, August 1989

(16) Shell Western E&P, Emission Measurements for Speciated PAH's and BTXE Compounds on a Gas fired Turbine and Steam Generator, June 24-27, 1991

(17) Marine Corps Base Camp Pendleton, California: Draft Final Air Toxics Emissions Inventory Report, May 1, 1991

(18) Entropy Environmentalists, Inc., Pooled Source Testing of a Rig Diesel-Fired Internal Combustion Engine, conducted for Western States Petroleum Association, July 29-31, 1992

(19) Radian Corporation, Source Test Report for the Texaco Heater Treater, the Mobil Steam Generator, and the SWEPI Gas Turbine in the San Joaquin Valley Unified Air Pollution Control District, September 1992

(20) AIRx Testing, Emissions Testing OLS Energu Natural Gas Fired Turbine, and Two Auxiliary Boilers, Job Number 22030, April 21, 1994

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

(g) VOC emissions from each unit shall not exceed

Emission Unit	VOC (lb/hr)	VOC (TPY, based on a 12-month rolling total)
23	20.4	25.5
24	20.4	25.5
25	20.4	25.5
26	20.4	25.5
27	30.6	38.25
28	30.6	38.25
29	20.4	25.5

[401 KAR 51:017]

Compliance Demonstration:
For each unit, the permittee shall demonstrate compliance using the results of the most recent performance test required by Subsection 3(b). Until the performance test emission factor has been determined, the permittee shall demonstrate compliance by using the hourly fuel usage rate and the vendor emission factor of 1.94 lbs/1000 gallon when burning fuel oil or the AP-42 emission factor of 2.14 lbs/MMscf when burning natural gas. To demonstrate compliance with twelve-month rolling total emission limit, the twelve-month total for each unit shall be calculated monthly and reported semi-annually. The permittee shall maintain onsite a log of each 12-month rolling total.

(h) Beryllium emissions from each unit shall not exceed the following limits [401 KAR 51:017]:

Emission Unit	Be (lb/hr)	Be (TPY, based on a 12-month rolling total)
23	3.37E-3	4.21E-3
24	3.37E-3	4.21E-3
25	3.37E-3	4.21E-3
26	3.37E-3	4.21E-3
27	5.057E-3	6.35E-3
28	5.057E-3	6.35E-3
29	3.37E-3	4.21E-3

Compliance Demonstration:
For each unit, the permittee shall demonstrate compliance using the results of the most recent performance test required by Subsection 3(b). Until performance testing is completed, the permittee shall demonstrate compliance when burning fuel oil by using the emission factor from the EPA document on Toxic Air Pollutants (EPA450/2-88-006a) of 4.5E-08 lbs/gallon. Until the performance testing is completed, the permittee shall be considered in compliance with the beryllium limit while burning natural gas.

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

As an alternative to conducting beryllium stack testing the permittee may use fuel supplier certification or fuel sampling for each fuel, consistent with the fuel monitoring plan in Subsection 4(e). For compliance demonstration, the permittee shall assume all beryllium in the fuel is emitted as beryllium.

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

3. Testing Requirements:

(a) The permittee shall conduct performance tests to determine nitrogen oxide and diluent concentration for each unit using either EPA Method 20, ASTM D6522-00, or EPA Method 7E and either EPA Method 3 or 3A in appendix A to 40 CFR Part 60. All performance tests shall conform to the requirements of 40 CFR 60.355. The permittee shall conduct nitrogen oxide performance testing on each unit at least once every 20 calendar quarters. [40 CFR 60.335(a) and 40 CFR Part 75, Appendix E, Section 2.2]

(b) To demonstrate compliance with the limits required by 401 KAR 51:017, the permittee shall conduct performance tests for carbon monoxide, particulate matter, VOC and beryllium for each unit, using Method 10 for carbon monoxide, Method 5 for particulate matter, Method 18 or 25 for VOC, and Method 104 for beryllium, or equivalents. Testing for each unit shall be conducted in conjunction with the nitrogen oxides testing, required by Subsection (a) above, once every 20 calendar quarters. Emission rates shall be determined on a pound per million Btu and pound per hour basis. For compliance demonstration and emission estimates, the permittee shall either (1) interpolate emission rates based on testing results at various load levels or (2) use the highest average emission rate over all load levels. [401 KAR 50:055]

4. Specific Monitoring Requirements:

(a) The permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption rate, hourly average heat input rate at ISO conditions, and the ratio of water or steam to fuel being fired in each unit [40 CFR 60.334(a)].

(b) The fuel consumption and the ratio of water or steam to fuel being fired in the unit shall be monitored during the performance test required in Subsection 3(a) to establish acceptable values and ranges. The permittee may supplement test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. To meet the parameter monitoring plan requirement (which explains the procedures used to document proper operation of the NO_X emission controls) the permittee has chosen to comply with the NO_X emission measurement methodology in Appendix E to 40 CFR Part 75, by developing and keeping onsite a quality-assurance (QA) plan, as described in Section 2.3 of Appendix E and Section 1.3.6 of Appendix B to 40 CFR Part 75. See Subsections 4(c) and 4(d) below. [40 CFR 60.334(g)]

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

(c) The permittee shall select at least four operating parameters indicative of each unit's NO_X formation characteristics, and define in the QA plan for the unit the acceptable ranges for these parameters at each tested load-heat input point. The acceptable parametric ranges should be based upon the turbine manufacturer's recommendations. Alternatively, the owner or operator may use sound engineering judgment and operating experience with the unit to establish the acceptable parametric ranges, provided that the rationale for selecting these ranges is included as part of the quality-assurance plan for the unit. If the turbine uses water or steam injection for NO_X control, the water/fuel or steam/fuel ratio shall be one of these parameters. During the NO_X-heat input correlation tests, record the average value of each parameter for each load-heat input to ensure that the parameters are within the acceptable range. Re-determine the NO_X emission rate-heat input correlation for each fuel after continuously exceeding the acceptable range of any of these parameters for one or more successive operating periods totaling more than 16 unit operating hours. [40 CFR 75, Appendix E, Section 2.3.1]

(d) When the operating levels of certain parameters exceed the limits specified in Subsection 4(c) above, or where the Division issues a notice requesting retesting because the NO_X emission rate data availability for when the unit operates within all quality assurance/quality control parameters in this section since the last test is less than 90.0 percent, as calculated by the Division, complete retesting of the NO_X emission rate by the earlier of: (1) 30 unit operating days (as defined in 40 CFR 72.2) or (2) 180 calendar days after exceeding the limits or after the date of issuance of a notice from the Division to re-verify the unit's NO_X emission rate. The permittee shall submit test results in accordance with 40 CFR 75.60 within 45 days of completing the retesting. [40 CFR 75, Appendix E, Section 2.3]

(e) The permittee shall continue to use the custom fuel monitoring plan, previously approved and provided in 40 CFR 75, Appendix D, Tables D4-D5 and Sections 2.2.1, 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3. The permittee shall maintain a copy onsite of the chosen monitoring plans for natural gas and oil. [40 CFR 60.334(h)(4)]

(f) Excluding the startup and shutdown periods, if any average emission value exceeds the hourly limits in Subsection 2, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and complete necessary process repairs or take corrective action as soon as practicable [401 KAR 52:020, Section 10].

5. **Specific Recordkeeping Requirements:**

(a) The permittee shall maintain records of the fuel consumption rates, hourly average heat input rate at ISO conditions, and water or steam to fuel ratios, as determined by the continuous monitoring system required by Subsection 4(a) [40 CFR 60.334(a)].

(b) The permittee shall maintain records of the hours of operation and power output (MW) for each unit on a monthly basis [401 KAR 52:020, Section 10].

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

(c) The permittee shall maintain records of the four (or more) operating parameters selected for the parameter monitoring plan in Subsection 4(c) on an hourly basis for each unit [401 KAR 52:020, Section 10].

(d) The permittee shall identify the recommended range of quality assurance- and quality control-related operating parameters. The permittee shall keep records of these operating parameters for each hour of unit operation (i.e., fuel combustion). The permittee shall keep a written record of the procedures used to perform NO_X emission rate testing. The permittee shall keep a copy of all data and results from the initial, and from the most recent, NO_X emission rate testing, including the values of quality assurance parameters specified in section 2.3 of Appendix E to 40 CFR Part 75. [40 CFR 75, Appendix B, Section 1.3.6]

(e) The permittee shall maintain records of the fuel monitoring plan in Subsection 4(e), including the results of each fuel sampling [401 KAR 52:020, Section 10].

(f) The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices, recorded in a permanent form suitable for inspection [401 KAR 52:020, Section 10].

(g) The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the emissions unit, any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative [401 KAR 52:020, Section 10].

(h) The permittee shall maintain records regarding all maintenance of the water injection system [401 KAR 52:020, Section 10].

6. **Specific Reporting Requirements:**

(a) The permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c) for each unit. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are:

(1) For nitrogen oxides, when using water or steam injection (excluding Emission Units 27 and 28 when burning natural gas) [40 CFR 60.334(j)(1)(i)]: