BEFORE THE ADMINISTRATOR

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Proposed Revised Operating Permit for the East Kentucky Power Cooperative, Inc. Hugh L. Spurlock Generating Station in Maysville, Kentucky.	Source I.D. No. 21-161-00009 Permit No. V-06-007 (Revision 2)

Proposed by the Kentucky Environmental Protection Cabinet Department for Environmental Protection Division for Air Quality on March 5, 2008.

PETITION REQUESTING THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF THE PROPOSED SECOND REVISED TITLE V OPERATING PERMIT FOR THE HUGH L. SPURLOCK GENERATING STATION IN MAYSVILLE, KENTUCKY.

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Pursuant to Clean Air Act § 505(b)(2) and 40 CFR § 70.8(d), the Sierra Club hereby petitions the Administrator ("the Administrator") of the United States Environmental Protection Agency ("U.S. EPA") to object to the proposed revised Title V Operating Permit for the Hugh L. Spurlock Generating Station in Maysville, Kentucky ("Permit"). A copy of the Permit is attached as Exhibit A.

Procedural Posture

The Kentucky Department for Environmental Protection Division for Air Quality (hereinafter "DAQ") proposed a Title V permit revision to U.S. EPA on June 12, 2006. That permit revision included provisions related to the construction and operation of a new circulating fluidized bed ("CFB") electric generating unit known as "Spurlock 4."

On August 15, 2006, Sierra Club petitioned the U.S. EPA to object to the revised Title V permit for the Spurlock plant. EPA received that petition on or before August 17, 2006. When the EPA failed to respond to Sierra Club's petition, Sierra Club filed a citizen suit to compel a response pursuant to 42 U.S.C. § 7604. Pursuant to a Consent Decree between Sierra Club and EPA, EPA agreed to issue a response to Sierra Club's petition. Consent Decree, *Sierra Club v. Johnson*, Case No. 1:07CV00414 (RWR) (D.D.C.).

On August 30, 2007, the EPA Administrator signed an order granting Sierra Club's petition in part and denying it in part. *See In re East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station*, Order Responding to Petitioner's Request that the Administrator Object to Issuance of State Permit (Adm'r Aug. 30, 2007) (hereinafter "Order"). A copy of the Administrator's decision is attached as Exhibit B. Sierra Club filed a petition with the United States Court of Appeals for the Sixth Circuit seeking a review of the Administrator's partial denial. *Sierra Club v. Envt'l Protection Agency*, Case No. 07-4487 (6th Cir.). That appeal is pending.

Prior to the June, 2006, proposed permit and Sierra Club's August, 2006, petition, EPA filed a lawsuit against East Kentucky Power Cooperative, Inc. ("EKPC"), on January 24, 2003. *U.S. v. East Kentucky Power Coop., Inc.*, Case No. 04-34 (E.D.Ky.). That lawsuit alleged, among other claims, that EKPC modified Unit 2 at the Spurlock plant without compliance with the Prevention of Significant Deterioration Program ("PSD"). On September 24, 2007, the United States District Court for the Eastern District of Kentucky entered an Order approving a Consent Decree between the United States and EKPC. *U.S. v. East Kentucky Power Coop., Inc.*, Order (Dkt. #180), Case No. 04-34 (E.D.Ky. Sept. 24, 2007). The United States subsequently requested, and the Court approved, a modification to certain provisions of the Consent Decree. *U.S. v. East Kentucky Power Coop., Inc.*, Order (Dkt. #187), Case No. 04-34 (E.D.Ky. April 22, 2008).

After the Administrator's Order objecting to the permit for EKPC's Spurlock plant, the Kentucky DAQ began to process a significant permit modification purporting to respond to the Administrator's objection. Kentucky DAQ made a draft of that proposed revision available to the public, upon request, on December 26, 2007. However, Kentucky DAQ did not publish notice of the draft permit, and begin a 30-day notice and comment period, until January 2, 2008, or later. Sierra Club submitted comments on the proposed draft revision on February 1, 2008. A copy of those comments is attached hereto as Exhibit C. Kentucky DAQ responded to comments and proposed the revision of the Spurlock Title V permit to EPA on or about March 5, 2008. A copy of Kentucky DAQ's response to comments is attached as Exhibit D. This response to comments was posted on the internet, but Sierra Club was not provided a copy. After the expiration of EPA's 45-day review, and after EPA did not object, Kentucky DAQ issued the final revised permit on April 18, 2008. Sierra Club was not provided a copy or notice of Kentucky DAQ's proposed or final permit.

Because the Kentucky DAQ did not issue a revised permit meeting the Administrator's objections within the 90 day period provided by 42 U.S.C. § 7661d(c), following the Administrator's objection dated August 30, 2007, the U.S. EPA is required to assume permitting responsibility for the Spurlock plant. On January 25, 2008, Sierra Club served EPA with Sierra Club's Notice of Intent to Sue, pursuant to 42 U.S.C. § 7604, for EPA's failure to assume this permitting responsibility. Sierra Club maintains that EPA is now required to issue or deny the operating permits, and revisions, for the Spurlock plant and, therefore, the current proposed revision to the permit by Kentucky DAQ is without legal effect. By submitting this petition Sierra Club does not waive its rights to challenge Kentucky DAQ's jurisdiction to issue the revision, nor Sierra Club's rights to sue to compel the EPA, rather than Kentucky, to issue the permit.

This petition is filed within sixty days following the end of U.S. EPA's 45-day review period as required by Clean Air Act ("CAA") § 505(b)(2). The Administrator must grant or deny this petition within sixty days after it is filed. If the U.S. EPA Administrator determines that the Permit does not comply with the requirements of the CAA or any "applicable requirement," he must object to issuance of the permit. 42

U.S.C. § 7661b(b); 40 C.F.R. § 70.8(c)(1) ("The [U.S. EPA] Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of this part."). "Applicable requirements" include, *inter alia*, any provision of the Kentucky State Implementation Plan ("SIP"), including Prevention of Significant Deterioration ("PSD") requirements, any term or condition of any preconstruction permit, any standard or requirement under Clean Air Act sections 111, 112, 114(a)(3), or 504, acid rain program requirements. 40 C.F.R. § 70.2.

This petition raises three issues. The first two issues correspond to the two permit revisions required by the Administrator's August 30, 2007 objection. First, the permit revision proposed by Kentucky DAQ fails to include the required 4850 MMBtu per hour heat input limit applicable to Unit 2 and unlawfully attempts to increase that limit without going through Prevention of Significant Deterioration (or any other Clean Air Act Title I) permitting. Second, Kentucky DAQ undertakes an erroneous review of cleaner fuel (lower sulfur content coal) that does not comport with the applicable law and EPA policy. The last issue is the lack of Hazardous Air Pollutant (HAP) emission limits under Clean Air Act section 112(g). This issues arises from the Court of Appeals for the District of Columbia's decision in *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), which was decided after the public comment period for the permit revision here and could not be raised in Sierra Club's public comments.

I. THE PROPOSED PERMIT OMITS AND ATTEMPTS TO UNLAWFULLY MODIFY THE APPLICABLE 4850 MMBTU PER HOUR HEAT INPUT LIMIT FOR UNIT 2.

As noted above, the Administrator objected to the prior Title V permit for the Spurlock plant because, inter alia, the permit failed to include the 4,850 MMBtu/hour heat input limit applicable to Unit 2. The Administrator fist pointed out that the failure of DAQ to include the 4,850 MMBtu/hour limit from a 1983 state operating permit in a prior, 1999, Title V permit did not revoke the heat input limit. Order at 12. The Administrator further pointed out that a Title V permit <u>cannot</u> change applicable requirements in underlying permits. *Id.* Therefore, the Administrator found that the 1983 permit limit of 4,850 MMBtu/hour remained as an applicable requirement. *Id.*

> Instead, the underlying permit in which the applicable requirement is found must be modified, and then incorporated into the Title V permit as an applicable requirement. Thus, the placement of the maximum heat input in the description section of EKPC's 1999 title V permit could not have eliminated the heat input limit as an applicable requirement of the underlying 1983 SOP.
>
> Based on the foregoing, EPA finds that the title V permit <u>is deficient for its failure to include as an applicable requirement the maximum heat input limit found in the underlying 1983 SOP</u>. Therefore, I grant the petition on this issue and direct KYDAQ to amend the permit and to include the applicable heat input limit for Unit 2 under the "Operating Limits" category of the permit.

Order at 12 (emphasis added). The "underlying SOP," or state operating permit, contained a 4,850 MMBtu/hour "maximum heat input" limit. See Kentucky Natural Resources and Environmental Protection Cabinet PERMIT, Re: H.L. Spurlock Power Station (November 10, 1982) (Attached as Exhibit E). Therefore, to satisfy the

Administrator's objection, this 4,850 MMBtu/hour maximum heat input limit must be included.

In response to Sierra Club's comments, Kentucky DAQ stated that it was required to increase the heat input limit for Unit 2 from 4,850 MMBtu/hour to 5,600 MMBtu/hour.

> Basis for this Revision: U. S. EPA Administrator's Order in response to Petition Number IV-2006-4. The underlying basis for the decision to increase the rated heat input of Unit 2 from 4850 MMBtu/hr to 5600 MMBtu/hr is the enforcement action, *U.S. v. East Kentucky Power Cooperative, Inc.,* Case No. 04-34-KSF (E.D. KY), and subsequent consent decree which requires this amendment to the Title V permit. The specific rationale for proposing to increase the limit in this permitting action is the permittee's application for a combined PSD review and Title V permit modification.

Response to Comments (Ex. D) at 2. This response misunderstands the basis for the 4,850 MMBtu/hour limit. The basis is not the "enforcement action," but the permits that EPA was enforcing in such action. More specifically, the 1983 State Operating Permit and the original PSD permit for Unit 2. Those permit were not, and could not be changed by the Consent Decree between EPA and EKPC.

Kentucky DAQ's response also ignored the directive in Administrator's objection, which instructed that the limit from the 1983 permit (4,850 MMBtu/hour) be included in the permit. Furthermore, DAQ's response ignores the Administrator's determination that a TitleV permit cannot modify a requirement of a prior permit issued pursuant to the Kentucky SIP, unless and until that underlying permit is also changed. Order at 12.[1]

A. The Administrator's Objection Requires A 4,850 MMBtu/hour Limit Or a PSD Review.

In its Response to Comments, Kentucky DAQ asserted that the Administrator's prior objection, and the Clean Air Act, merely require EKPC to request a Title V permit revision to allow a 5,600 MMBtu heat input pursuant to the Consent Decree between EKPC and the EPA.

> The Administrator stated "KYDAQ must amend EKPC's Title V permit to incorporate the maximum heat input limit from the underlying state permit or EKPC must apply to KYDAQ under the Kentucky SIP for a permit that would authorize a change in that heat input limit, which in turn would be incorporated in the Title V permit." Paragraph 165 of the consent decree between U.S. EPA and EKPC, Civil Action 04-34-KSF, required EKPC to "apply for amendment of its Title V permit for the Spurlock plant to incorporate an MCR of 5600 mmBTU/hr for Spurlock Unit 2." EKPC applied as required by paragraph 165 and thus the draft permit meets the Administrator's objection.

Response to Comments (Ex. D) at 7. In other words, Kentucky DAQ asserts that a 5,600 MMBtu/hour limit is required by the consent decree. This is a fundamental misunderstanding of both the Administrator's Order and the applicable law. The Administrator's prior order expressly rejected the idea that the Consent Decree, and

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[1] The Administrator's Order noted that the heat rate could be changed through a combined PSD and Title V review. Order at 13. While Kentucky DAQ's response to comments implies that this occurred, it did not. There was no PSD review, nor any other review beyond a modification to the Title V permit. A PSD review would have included best available control technology determinations as well as air quality and increment impact and other analyses.

specifically paragraph 165 of the Consent Decree, changed required 4,850 MMBtu/hour heat input limit.

> EPA wishes to emphasize that its decision to grant Petitioner's request on this issue does not conflict with the proposed consent decree that will resolve EPA's civil enforcement action for EKPC's alleged violations of the maximum heat input limit contained its underlying state operating permit, filed on January 29, 2004. Paragraph 165 of the proposed consent decree requires EKPC to apply for an amendment to its title V permit for the Spurlock Plant that incorporates a maximum continuous rating (MCR) of 5,600 mmBtu/hour. <u>The proposed consent decree does not provide that this MCR replaces the 4,850 mmBtu/hour heat input limit found in its underlying 1983 SOP, nor does it otherwise alter the maximum heat input limit contained in the underlying 1983 SOP</u>.
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> Further, although the proposed consent decree in paragraph 119 releases EKPC from claims arising from the alleged violations of Parts C and D of the Act, failure to obtain an operating permit that incorporates applicable requirements under the Kentucky SIP, and operation of Spurlock Unit 2 above a maximum heat input of 4,850 mmBtu/hr, the proposed consent decree <u>does not relieve KYDAQ of its obligation under Section 504</u>, 42 U.S.C. § 7661c, and 401 KAR 52.020, to ensure that the Spurlock Unit 2 title V permit contain all applicable requirements under the Act. This includes the maximum heat input limit contained in EKPC's 1983 SOP.

Order at 13 (emphasis added). Therefore, DAQ's assertion that the Consent Decree mandates the substitution of a 5,600 MMBtu/hour limit for the 4,850 MMBtu/hour limit is directly contradicted by the Administrator's prior decision.

Furthermore, to the extent that the Administrator's prior Order allowed for the possibility that EKPC could apply for a revision to the 4850 MMBtu/hour input limit under the Kentucky SIP, the Administrator was clearly referring to either the PSD program or another Clean Air Act Title I program (e.g., minor source construction permit) in the Kentucky SIP. This was merely recognizing that a source may increase heat input—and therefore emissions—through a permitted modification to the facility. The Administrator did not assert, and could not have meant, that this heat input limit could be changed through a Title V permit (as Kentucky DAQ attempts to do) for several reasons. First, the Order expressly rejects the concept of a Title V permit revising underlying requirements:

> In addition, the [District Court's decision in *U.S. v. East Kentucky Power Cooperative, Inc.*] cannot be read to mean that the heat input limit in the 1983 SOP was not an "applicable requirement" within the meaning of 40 C.F.R. § 70.2, or that the title V permit eliminated the heat input requirement from the 1983 SOP. <u>The title V program does not impose new applicable requirements nor is the title V permitting process the appropriate mechanism for changing or modifying applicable requirements found in underlying permits.</u> Instead, the underlying permit in which the applicable requirement is found must be modified, and then incorporated into the title V permit as an applicable requirement.

Order at 12 (emphasis added). The Administrator further emphasized that he was rejecting the possibility of a heat input limit change through a Title V permit: "To the extent that a state with a merged title V/PSD permitting program (such as Kentucky's) seeks to change applicable requirements in an underlying permit, such changes must be clearly delineated as being made <u>outside of the title V part of the process</u> and the rationale for the change must be clearly stated." Order at 12 n.6 (emphasis added). In other words, the heat input limit can only be changed through non-Title V processes. That was not done here. Nevertheless, Kentucky DAQ contends that it can now change the applicable heat input limit to 5,600 MMBtu/hour in the proposed revised Title V permit.

Moreover, the proposed permit modification undermines the PSD program. As alleged in the EPA's complaint filed against EKPC, an increase from 4,850 MMBtu/hour to 5,600 MMBtu/hour results in increased annual emissions greater than the "significant" threshold. Complaint, *U.S. v. East Kentucky Power Cooperative, Inc.*, Case No. 04-34-KSF ¶ 49 (E.D. Ky) ("...Defendant [EKPC] commenced construction of one or more major modifications, as defined in the Act and the Kentucky SIP, at the Spurlock Plant. These modifications included one or more physical changes or changes in the method of operation at Spurlock Unit No. 2, including ... increasing the heat input rate at the unit."); *see also id.* ¶ 50 (asserting that it is a violation of PSD requirements to, *inter alia*, increase the heat input above 4,850 MMBtu/hour without undergoing PSD review). Specifically, the increase of 750 MMBtu/hour (5,600 - 4,850), multiplied by the emission rate from the boilers for NO_x, SO_2, CO, PM, PM10 and other PSD pollutants results in increases greater than those in 40 C.F.R. § 52.21(b)(23)(i) and 401 KAR 51:001(222)(a).[2]

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[2] For example, the EPA's Acid Rain Air Markets Database indicates a NOx emission rate of 0.17 lb/MMBtu for Unit 2 (0.17 lb/MMBtu * 750 MMBtu/hour * 8760 hours/year/2000 lb/ton = 558.5 tons/year). The Database also indicates an SO_2 emission rate of 1.03 lb/MMBtu for Unit 2 (1.03 lb/MMBtu * 750 MMBtu/hour * 8760 hours/year/2000 lb/ton = 3383.6 tons/year).

In fact, contrary to its proposed permit revision increasing the heat input to Unit 2 at issue here, the Kentucky DAQ previously denied EKPC's request to increase the heat rate limit through a prior Title V permit unless EKPC went through PSD permitting. In December, 1993, East Kentucky sought an increase in the permitted maximum hourly heath input for Unit 2 from 4850 to 5355 MMBtu/hour. Letter from Robert E. Hughes, Jr., EKPC, to John Hornback, KDAQ Re: H.L. Spurlock Power Station- Unit #2 BTU Heat Input (attached hereto as Exhibit F). In February, 1994, DAQ responded by asserting that any such increase would be considered a major modification under the PSD rules and would be subject to PSD permitting requirements if it resulted in a significant net emissions increase. Letter from Gerald R. Goebel, KDAQ, to Robert E. Hughes, Jr., EKPC Re: Request to increase permitted heat input for Unit 2 at the H.L. Spurlock Station (R7532) I.C. # 103-2640-0009 (February 3, 1994) (attached hereto as Exhibit G). Specifically, DAQ stated that "the Permit Review Branch has determined that if the proposed increase in the heat input rate results in a significant net emissions increase, then your proposal would be a major modification, as defined in Regulation 401 KAR 51:017." *Id.* In January, 1995, EKPC conceded that the 4850 MMBtu/hour heat input cannot be changed without undergoing PSD permitting and rescinded its request for the heat rate increase. Letter from Robert E. Hughes, Jr., EKPC, to Gerald R. Goebel, KDAQ Re: Letter of December 20, 1994 Spurlock Unit 2 (January 16, 1995) (attached hereto as exhibit H); *see also* Order at 12 n.7 ("It is apparent that the EKPC was aware that the heat input limit was an enforceable limitation in that it previously requested that KYDAQ revise the maximum heat rate for Unit 2 from

4,850 million [sic] mmBtu/hr to 5,3555 [sic, 5,355] mmBtu/hr. KYDAQ denied EKPC's request when they informed EKPC that a PSD permit was required for such modification."). Nevertheless, the proposed permit before the EPA would grant the very heat input increase that both DAQ[3] and EPA previously determined to be prohibited unless and until a PSD permit was issued. This is unlawful and arbitrary and EPA must object.

B. A 4850 MMBtu/hour Limit Is Also Required By The EPA-Issued PSD Permit For Unit 2 That Cannot Be Changed Except By EPA Through A New PSD Permit.

In addition to failing to comply with the Administrator's order to include a 4,850 MMBtu/hour heat input limit, and constituting a major modification subject to PSD review, the proposed permit revision is also unlawful because it would modify an EPA-issued PSD permit.

Although the Administrator's prior Order objecting to the Spurlock Title V permit for lack of a 4,850 MMBtu/hour limit for Unit 2 cited only the 1983 State Operating Permit, the 4,850 MMBtu/hour limit is also an "applicable requirement" under Title V because it is required by a PSD permit issued by U.S. EPA for the unit. This was raised in Sierra Club's prior petition to the Administrator, but because the Administrator found that the 4,850 MMBtu/hour limit was required by the 1983 State Operating Permit, and objection on that basis, it did not reach the question of whether

[3] Kentucky DAQ reaffirmed, during the public comment process for the 1999 Title V permit for the Spurlock plant, that EKPC could not increase the maximum heat rate for Unit 2 to 5600 MMBtu/hour without undergoing PSD review. Response to East Kentucky Power's Comments (3/13/98 Letter) at 2 (attached as Exhibit M).

the 4,850 MMBtu/hour limit was also required by the original PSD permit for Unit 2. *See* Petition Requesting that the Administrator Object, Petition No. IV-2006-4 at 7-8 (Aug. 15, 2006).

When EKPC applied for a permit to construct Unit 2 in January 1976, EKPC represented to U.S. EPA that EKPC would construct and operate a pulverized coal unit with a maximum heat input of 4,850 million Btu/hour. *See* Letter from Ronald L. Rainson, EKPC, to G.T. Helms, U.S. EPA and attachments (March 19, 1976) (attached as Exhibit I); Letter from William Gill, EKPC, to Frank L. Stanonis, Kentucky Bureau of Environmental Quality, and attachments (January 23, 1976) (attached as Exhibit J). This representation of the 4,850 MMBtu/hour maximum heat rate becomes an enforceable requirement because 40 C.F.R. § 52.21(r), which is applicable because the original PSD permit for Unit was issued by U.S. EPA pursuant to Part 52, 54 Fed. Reg. at 36,309, requires that a PSD applicant construct and operate the source consistent with and according to the specifications provided in its permit application.

Furthermore, as is apparent from U.S. EPA's review and administrative findings in support of the PSD permit issued for Unit 2, U.S. EPA relied on the maximum 4,850 MMBtu/hour heat input when determining air quality impacts and issuing the permit. *See* Letter from J. Little, U.S. EPA to Robert Hughes, EKPC, attaching analysis and permit (September 21, 1976) (attached hereto as Exhibit K). EPA has previously noted that EKPC's application to construct Unit 2 represented to EPA that Unit 2 would have a heat input limit of 4,850 MMBtu/hour, and that EPA relied upon that representation when permitting Unit 2. *See* Pl. Mem. Supp. Fourth Mot. Summary Judgment at 36-37, *U.S. v. East Kentucky Power Cooperative, Inc.*, Case No. 04-34 (E.D.Ky) ("... the air quality modeling and compliance determinations performed by EPA and KDAQ when EKPC first sought approval to construct Spurlock Unit 2 were all based on the heat input rate information provided by EKPC in its applications. SOF ¶¶ 12, 13, 19, 20. By increasing its heat input over the levels identified in its applications, EKPC has fundamentally changed the assumptions upon which approval to construct the unit was based. If air quality modeling were to be redone using a higher heat input capacity and the same coal sulfur content that was identified in EKPC's permit application and subsequent permits, the unit would have been modeled at a higher emissions rate because increasing the heat input rate is directly proportional to the amount of emissions from a unit."); *see also id.* at 9-10 (representing to the Court, pursuant to Fed. R. Civ. P. 56, that it was <u>undisputed</u> that EKPC's PSD application identified 4850 MMBtu/hour as the maximum heat rate and that EPA relied upon that representation to issue a PSD construction permit). Therefore, the 4,850 MMBtu/hour heat input from EKPC's PSD application becomes an enforceable PSD requirement. 40 C.F.R. § 52.21(r). This PSD requirement cannot be modified through a Title V permit revision. Kentucky DAQ's attempt to do so here is unlawful and requires an objection by the Administrator.

II. KENTUCKY DAQ ERRONEOUSLY REJECTED USE OF CLEAN FUELS AS BACT FOR SO2.

The Administrator's Order concluded that EKPC and Kentucky DAQ failed to provide an adequate explanation for rejecting low sulfur coal as not economically viable in a top-down BACT analysis. Order at 29-32. The Kentucky DAQ revised its prior

Statement of Basis in an attempt to justify its pre-determined outcome—finding lower sulfur coal to be economically infeasible. Kentucky DAQ ignored substantive public comments on its justification and, instead, asserted that EPA had approved its attempt prior to the close of public notice and comment:

> In accordance with the Administrator's objection, DAQ revised the statement of basis for permit V-06-007 Revision 2 to include justification for excluding low sulphur eastern bituminous coal as BACT for SO2. DAQ included such justification in the Statement of Basis for this permit. By letter dated February 27, 2008, U.S. EPA informed DAQ that "[t]he draft permit revision, more specifically the statement of basis adequately addresses the requirement to provide sufficient justification for eliminating low-sulfur eastern bituminous coal as best available control technology (for sulfur dioxide emissions) for Emission Unit 17 (Unit #4)." Therefore the objection has been resolved.

Response to Comments at 14. No further response to Sierra Club's detailed comments was provided.

Fundamental to the Title V and PSD permitting processes is the idea that the public should be part of the process. It is foreign to that concept that EPA and the state can agree to outcomes without considering public comments. Therefore, Sierra Club presumes that EPA has not directed Kentucky DAQ to ignore Sierra Club's comments regarding sulfur content and that DAQ's belief that this occurred is in error. The Kentucky DAQ's failure to respond to Sierra Club's substantive comments, alone, requires an objection by the Administrator. *See In re Midwest Generation, LLC, Joliet Generating Station*, Petition No. V-2004-3, Order at 5 (Adm'r June 24, 2005) ("It is a general principle of administrative law that an inherent component of any meaningful notice and opportunity for comment is a response by the regulatory authority to significant comments.") (*citing Home Box Office v. FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977); *In re Consolidated Edison Co., Hudson Ave. Generating Station*, Petition II-220-10, Order at 8 (September 30, 2003)); *see also In re Midwest Generating, LLC, Waukegan Generating Station*, Petition No. V-2004-5, Order at 4 (Adm'r, September 22, 2005) (same); *In re Midwest Generating, LLC, Crawford Generating Station*, Petition No. V-2004-2, Order at 5-6 (Adm'r, March 25, 2005) (same); *In re Midwest Generating, LLC, Fisk Generating Station*, Petition No. V-2004-1, Order at 5-6 (Adm'r, March 25, 2005) (same).

Furthermore, notwithstanding DAQ's refusal to consider them, Sierra Club's comments demonstrated that Kentucky DAQ's cost-effectiveness analysis was wrong. DAQ's revised Statement of Basis ("SOB") calculated the cost of using low sulfur eastern bituminous coals as between $9,317 and $25,665 per <u>additional ton</u> of SO_2 removed. SOB at 4. The SOB then compared this value with <u>incremental cost effectiveness</u> values for other projects without disclosing that DAQ was relying on incremental cost effectiveness values. *Id.* Based on its comparison of incremental values, DAQ concluded in its SOB that low sulfur coal is not cost effective based on "other permitting authorities [that] have rejected additional sulfur removal costs above $5,000/ton as being excessive for BACT." *Id.* at 4-5.

Unfortunately, Kentucky DAQ's analysis contained fundamental errors. If Kentucky DAQ would have applied the actual test for top-down BACT analyses-- <u>average cost effectiveness</u> of removing additional SO_2 by using low sulfur coal—it would have concluded that the cost is $155 to $427/ton, which is <u>lower</u> than other cost-effectiveness determinations and should be the basis of BACT for Spurlock Unit 4.

A. DAQ Failed to Use Average And Incremental Cost.

Average and incremental cost effectiveness are the economic criteria used to determine if a control option is economically feasible in a BACT analysis. *New Source Review Workshop Manual* Sec. IV.D.2 (Draft October 1990) ("NSR Manual"). However, EKPC and Kentucky DAQ's analysis[4] in response to the Administrator's Order requiring a top-down analysis of low sulfur coal included a <u>single</u> metric which is <u>neither</u> average nor incremental cost effectiveness.

DAQ compared the cost of fuel switching (one step) with the reductions achieved by a <u>three-step</u> control regime that includes fuel, limestone addition to the CFB bed, and dry scrubbing. More specifically, the DAQ provided the following analysis:

- First, the SOB calculates the difference in the annual cost to purchase the design fuel (9 lb SO_2/MMBtu and 10,757 Btu/lb) compared to the cost to purchase low sulfur fuel (1.2 lb SO_2/MMBtu and 12,500 Btu/lb) in dollars per year:

[Annual Cost of Design Coal – Annual Cost of Low S Coal] (1)

- Second, the SOB calculates the amount of SO_2 emitted when burning design fuel compared to the amount of SO_2 emitted when burning low sulfur coal in tons per year, <u>assuming 99.33% SO_2 removal in both cases</u>[5] using limestone addition to the CFB bed and a dry scrubber:

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[4] Kentucky DAQ refers to its analysis as "cost comparison ($/ton)" and "cost of removal of an additional ton of SO_2." SOB at 3-4.

[5] Note that DAQ used a high control efficiency of 99.33%. This is now what it used to establish a BACT limit in the original permit. A BACT limit based on 99.33% control would have resulted in an SO2 limit of 0.02 lb/MMBtu—even assuming the high-sulfur design fuel. By applying this high control efficiency, DAQ inflates the amount of

[SO_2 Emitted Design Coal – SO_2 Emitted Low S Coal] (2)

- Finally, the SOB divides the incremental annual fuel cost by the incremental amount of SO_2 emitted and calls the results the cost per additional ton of SO2 emitted. As an example, the lower end of the SOB's cost range is calculated as:

[$44,582,093/yr - $29,730,565/yr]/[1840 ton/yr - 246 ton/yr] = ***$9,317/ton***

The numerator (top) and the denominator (bottom) in this calculation are apples to oranges. The numerator is the difference in fuel costs, a single component of the total costs of a pollution control system.[6] The denominator is the difference in tons removed by the entire pollution control. This method is not a recognized economic feasibility metric because it distorts cost effectiveness and substantially penalizes low sulfur fuel by including SO2 emission reductions achieved by other control options [limestone addition and scrubbing] while excluding the relative costs of these other controls. As set forth below, when the full cost is divided by the full SO2 reduction, as required by EPA guidance (which DAQ purports to follow), clean fuel is cost effective.

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control for high sulfur coal—reducing the delta between high sulfur and low sulfur coal—and making the low sulfur coal appear incrementally more costly. If DAQ and EKPC use 99.33% as the control efficiency to justify rejecting low sulfur coal, they must be consistent and use this efficiency to establish a BACT limit (0.020 lb/MMBtu).

[6] The control costs for design fuel for the entire control train is higher than for low sulfur coal because a bigger, more efficient scrubber must be used; more limestone must be added to the fluidized bed; more water must be used to cool the flue gases; more solid wastes must be disposed; more electricity must be used to operate the scrubber; and more lime must be injected into the scrubber, among other increased costs incurred for the complete control trains as compared to just low sulfur coal. If the cost of these additional controls were included in both the cost of design coal and the low sulfur option, they would add substantially to the design coal costs and much less so to the low sulfur coal, thus narrowing the incremental cost. For example, for the high-sulfur, "design coal," the limestone bed plus dry scrubber must reduce SO_2 emissions from 110,376 ton/yr to 1,840 ton/yr, or by **108,536 ton/yr**. However, for low sulfur coal, these controls need only reduce SO_2 from 14,717 ton/yr to 246 ton/yr or by **14,471 ton/yr**. SOB at 3. In other words, less limestone and a smaller scrubber is required with low sulfur coal, resulting in lower scrubber operation costs. The cost to remove **108,536 ton/yr** of SO_2 with limestone injection and a scrubber when burning high-sulfur (design) coal is substantially higher than the cost to remove only **14,471 ton/yr** when burning low sulfur coal. Because DAQ did not consider the cost-effectiveness of the

The Kentucky DAQ did not calculate average cost effectiveness, which is the ratio of the control option annualized cost divided by the control option annual emission reduction. *NSR Manual* at B.36-B.37. In other words, to calculate average cost effectiveness, the numerator should be the cost of the entire pollution control train, including fuel. The denominator should be the difference in tons removed by the entire pollution control train. The key here is that the cost of the pollution control train when low sulfur coal is used is substantially smaller as it must remove less sulfur than when high sulfur fuel is used. If DAQ had used the correct method to calculate cost effectiveness of low sulfur coal, it would have determined a range from $155/ton to $427/ton.[7] This is below the lower end of the range of both average cost effectiveness ($527 to $4054/ton) and incremental cost effectiveness ($5,000-20,000/ton) cited by DAQ as being cost-effective (which is actually much lower thresholds than other permitting authorities use).[8]

Kentucky DAQ also did not correctly calculate incremental cost effectiveness, which is the ratio of the difference in annualized cost of two control options to the difference in the emission rates of these same two control options. *NSR Manual* at B.41. This is a meaningless metric here because both options were assumed to meet the same emission level. Thus, the denominator is zero. Division by zero is not defined.

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entire control-train together, it failed to account for the economic benefit of controlling less SO2 with less limestone and smaller scrubber when burning lower sulfur coal.

[7] The lower end of the range from SOB, p. 4: ($14,851,528/yr)/(95,659 ton SO_2/yr) = $155/yr. The upper end of the range from SOB, p. 3: ($40,910,075/yr)/(95,659 ton SO_2/yr) = $427.67/ton.

[8] U.S. EPA Region 8, Response to Public Comments on Draft Air Pollution Control Prevention of Significant Deterioration (PSD) Permit to Construction, Deseret Power Electric Cooperative, August 30, 2007, pp. 29-33.

DAQ's analysis is not only inconsistent with the method EPA and Kentucky DAQ usually use, but it appears designed to prejudice the BACT analysis against cleaner fuels, contrary to Congress' clear direction that clean fuels be used. 42 U.S.C. § 7479(3) (defining BACT to include consideration of "clean fuels"); see also *Inter-Power of New York*, 5 E.A.D. 130, 134 (1994); *In re Old Dominion Elec. Coop.*, 3 E.A.D. at 794, n. 39 (EAB 1992) ("BACT analysis should include consideration of cleaner forms of the fuel proposed by the source."); *In re Hibbing Taconite Co.*, 2 E.A.D. 838, 842-43 (Adm'r 1989) (remanding a permit because the permitting agency failed to consider burning natural gas as a viable pollution control strategy); Letter from JoAnn Heiman, Chief Air Permitting and Compliance Branch, EPA Region 7, to Clark Duffy, Kansas Department of Health & Environment, Re: Comments on Sunflower Holcomb Station Expansion Project for New Units H2, H3 and H4 (November 9, 2006) (rejecting Kansas' assumption that 1.23 lbs/MMbtu coal should be assumed as the coal sulfur content for BACT and requiring a lower sulfur content).

B. DAQ Failed to Use Representative Comparative Costs.

The DAQ's revised SOB uses an analysis it terms "cost comparison" or "dollars per additional ton of SO_2 removed" to compare the cost of fuel switching to the incremental cost effectiveness of post combustion controls (i.e., various types of dry scrubbers and sorbent injection). SOB at 4.[9] As explained above, this is an apples-to-oranges comparison. Further, it creates a number of errors.

[9] The SOB does not disclose the control technology, but the source of the comparative cost data, EPA's response to comments in the Desert case, does disclose the controls.

First, even assuming that Kentucky DAQ correctly calculated cost effectiveness (which it did not), the *NSR Manual* states that "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if **any**, between the application of the control technology on those sources and the particular source under review." *NSR Manual* at 31 (underline emphasis). The "technology" at issue here is the low sulfur coal. A correct analysis would look to whether the cost of the technology (low sulfur coal) at Spurlock 4 with the cost of the technology at other sources where it is used. Put another way, the cost of controlling additional SO2 with low sulfur coal must be compared to the costs incurred by other plants that burn low sulfur coal. The *NSR Manual* elaborates that: "if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT." *NSR Manual*, p. B.44 (emphasis added). There was no attempt by Kentucky DAQ to compare the cost of using low sulfur coal at other boilers with the cost at Spurlock 4.

Second, cost comparisons must be on an "apples-to-apples" basis. E.g., *NSR Manual* at B.39 (stating that a source that compares costs between options must do so with standard assumptions for all options, discussing an 85% capacity factor in that case). The comparative cost data are based on incremental cost effectiveness, calculated as explained in the *NSR Manual* at p. B.41, such as the cost of a wet scrubber with the cost of a dry scrubber. Here, however, the Kentucky DAQ attempted to compare the high sulfur fuel costs, alone, to the emission reductions based on low sulfur coal plus both a limestone CFB bed and a dry scrubber. This distorts the comparison and inflates the cost per ton calculation. The comparison should have been the high-sulfur coal to low-sulfur coal, or the high-sulfur coal plus scrubbing to the low-sulfur coal plus scrubbing.

Third, the EPA cost data used by Kentucky DAQ to gauge "cost effectiveness" are not comparable to the cost of low sulfur coal at Spurlock 4 as the data are based on different assumptions as to capacity factor (Longleaf, for example, assumed 85%), SO_2 control efficiency (Cargil, for example, assumes only 75% SO_2 control efficiency for SDA while others assume 90%+), interest rate, and equipment life, factors that must be constant from plant to plant to be used in a comparative cost analysis. DAQ's analysis fails to account for these differences.

C. KDAQ Failed to Use Range Of Comparative Cost Data

Kentucky DAQ's analysis also improperly compared the upper-end cost value the agency calculated, $9,317/ton, with the lower end of the range of the reported comparative cost data. Notably, the incremental cost data that the agency summarized from EPA ranges from $5,000/ton to $23,855/ton. A control option is considered cost effective if it is "within the range of normal costs for that control alternative..." *NSR Manual* at B.31 (emphasis added). Therefore, if Kentucky DAQ had properly considered the range of comparable costs, it would have concluded that all of the cost values DAQ calculated and reported in its SOB (which range from $9,317/ton to $25,665/ton) were well within the range of reported comparative cost data. DAQ improperly used a single determination, by Pennsylvania for the River Hill CFB[10], as the appropriate comparison of costs. Furthermore, Kentucky DAQ failed to recognize that the determination for River Hill was based on an application submitted in July 2004. Pollution control costs have escalated dramatically since mid-2004.[11] As a result, what is cost effective today may be greater, in unadjusted dollars, than what was considered cost effective four years ago.

Moreover, DAQ conducted its calculations with 2006 dollars, but used caparisons from 2004 determinations. By adjusting the 2004 River Hill cost data (based on scrubbers) to 2006 dollars-- using the Vatavuk cost index-- the $5,000/ton value relied on by KDAQ becomes $7,040/ton in 2006 dollars.[12] Adjusting to current dollars (2008) would result in a similar increase. Even if 2006 dollars are used, the ~$7,000/ton value is within about 30% of the cost threshold value proffered by DAQ, $9,317. Costs that are this close are assumed to be cost effective. *NSR Manual* B.44 ("Study cost estimates used in BACT are typically accurate to +/- 20 to 30 percent. Therefore, control cost options which are within +/- 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options."); *id.* at B.44

[10] This analysis, and the other prior determinations by other agencies cited by Kentucky DAQ were incorrectly done. None determined that the cost of cleaner fuel was unusual compared to costs borne by other similar facilities – the test for BACT and the test required by the Administrator's Order. In other words, DAQ cites erroneous prior determinations as support for its own erroneous determination.

[11] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007.

("if the cost...is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT.") Thus, low sulfur coal is cost effective <u>even under DAQ's incorrect metric</u> for calculating the cost per ton, and even using 2006 rather than 2008 dollars.[13]

D. A Correct BACT Analysis Must Consider Combinations Of Controls

After the errors in Kentucky's post hoc justification of dirty, high-sulfur, coal are corrected, low sulfur coal cannot be eliminated based on adverse economic impacts. The permit record contains no evidence that low sulfur coal is otherwise infeasible for this source (i.e., based on energy, economic, or factors other than cost). Indeed, there are other similar boilers using much cleaner fuel than assumed in the Spurlock 4 BACT analysis, demonstrating that clean fuels is available. Order at n.11.

It should also be noted that Kentucky DAQ's analysis assumed that scrubbing plus limestone CFB bed can achieve 99.33% SO_2 after including cleaner fuel (low sulfur coal). SOB at 3. This control efficiency results in a calculation indicating a higher incremental cost for low sulfur coal. However, it is inconstant with the control efficiency DAQ assumed when establishing a BACT limit for high sulfur "design" coal. If DAQ was consistent, it would have established a BACT limit in the original permit of 0.02 lb/MMBtu based on 99.33% control of design coal. Alternatively, if it would have

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[12] River Hill costs adjusted to 2006 using the Vatavuk cost index for scrubber: ($5000)(169.1/120.1). The cost indices are from the journal, Chemical Engineering.

[13] The next lowest value used by DAQ for comparison is similarly not representative, but does indicate that costs of $5,900 <u>are</u> cost-effective for cleaner fuels. The plant, a Cargill boiler in Nebraska, was

been consistent and applied a lower control efficiency equivalent to the permit's SO2 limit when calculating incremental cost-effectiveness, it would have concluded that the incremental cost of low sulfur coal is much lower. Only through inconsistent assumptions favorable to the applicant can Kentucky DAQ justify the high SO_2 limit in the permit.

Because DAQ's analysis is inconsistent with the applicable law, inconsistent with the NSR Manual that DAQ purports to follow, and inconsistent with DAQ's own prior assumptions, the rejection of low sulfur coal as the basis for BACT is unlawful, arbitrary and capricious. The Administrator must object.

III. THE ADMINISTRATOR MUST OBJECT BECAUSE THE PERMIT LACKS MACT DETERMINATIONS FOR MERCURY AND OTHER HAZARDOUS AIR POLLUTANTS FROM THE MAIN BOILER.

The Administrator must object to the Title V permit because it lacks case-by-case MACT determinations for mercury and other hazardous air pollutants ("HAPs") from Unit 4. Pursuant to section 112 of the Act, categories of sources listed pursuant to section 112(c) are subject to the case-by-case MACT requirements of section 112(g) when EPA has not promulgated a national standard. 42 U.S.C. §§ 7412(c)(1) (Administrator shall publish a list of all categories and subcategories of major sources of HAPs), 7412(g)(2) (requiring MACT of new and modified major sources of HAPs, which is determined on a case-by-case basis where the Administrator has not established emission limitations). New and modified major sources of HAPs have been subject to Clean Air Act section 112(g) since 2000. On December 20, 2000, the Administrator

required to use lower sulfur coal than proposed by the applicant (2.7 lb SO_2/MMBtu compared to its issued a determination under Section 112(n) that it was "appropriate and necessary" to regulate coal- and oil-burning electric generating units (EGUs) under the HAPs program. *Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units,* 65 Fed. Reg. 79,825, 79,827 (Dec. 20, 2000) ("2000 Determination"). In that determination, EPA found that EGUs present significant hazards to public health and the environment. *Id.* at 79,827. As a result, EGUs were listed under Section 112(c). *National Emission Standards for Hazardous Air Pollutants:Revision of Source Category List Under Section 112 of the Clean Air Act,* 67 Fed. Reg. 6521, 6522, 6524 (Feb. 12, 2002). While U.S. EPA proposed a numeric HAP emission standard for coal-fired EGUs in January 2004, *Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources:Electric Utility Steam Generating Units,* 69 Fed. Reg. 4754 (Jan. 30, 2004), this standard was never finalized. Therefore, case-by-case limits are required pursuant to § 112(g). *See also* Memorandum from John Seitz, U.S. EPA, to Regional Air Directors, at p. 1 (Aug. 1, 2001).

EPA's attempt to un-do this listing was rejected and vacated. *New Jersey v. EPA,* 517 F.3d 574, 583 (D.C. Cir. 2008). Therefore, following the Court's mandate in *New Jersey v. EPA,* electric generating units ("EGUs") are subject to the case-by-case MACT requirements laid out in Section 112 of the Clean Air Act. 517 F.3d 574 (D.C. Cir. Feb 8, 2008) (mandate issued March 14, 2008).

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proposal of 3.57 lb SO_2/MMBtu). Cargil Final Permit at pdf 32.

A Title V permit must include "enforceable emission limitations and standards" and other provisions "as are necessary to assure compliance with applicable requirements of [the Clean Air Act]." 42 U.S.C. 7661c(a). Applicable requirements include requirements under Clean Air Act section 112. 40 C.F.R. § 70.2. Therefore, where a Title V permit is issued for a new or modified source subject to section 112(g), the case-by-case HAP limits must be incorporated into the source's Title V permit for each HAP. *Id.*; 40 C.F.R. § 63.43; *National Lime Assoc. v. EPA*, 233 F.3d 625, 634 (D.C. Cir. 2000) (MACT requirements apply to each of the HAPs that a source will emit). The Proposed Permit for Spurlock does not include a MACT limit for hazardous air pollutants from Unit 4. Therefore, the Administrator must object.[14]

Dated this 28th day of April, 2008.

Attorneys for Sierra Club
GARVEY MCNEIL & MCGILLIVRAY, S.C.

David C. Bender

[14] This petition is timely, pursuant to 42 U.S.C. § 7661d(b)(2), despite the fact that Sierra Club's public comments do not address this issue, because the basis is the Court of Appeals' mandate that issued on April 14, 2008. The comments submitted by Sierra Club were due well before the issuance of the mandate. In fact, the comments were submitted a week before the D.C. Circuit's opinion, and more than two months before the mandate. Therefore, it was "impracticable to raise such objections within [the comment] period" and "the grounds for such objection arose after such period." 42 U.S.C. § 7661d(b)(2).

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Proposed Revised Operating Permit for the East Kentucky Power Cooperative, Inc. Hugh L. Spurlock Generating Station in Maysville, Kentucky.	Source I.D. No. 21-161-00009 Permit No. V-06-007 (Revision 2)
Proposed by the Kentucky Environmental Protection Cabinet Department for Environmental Protection Division for Air Quality on March 5, 2008.	

CERTIFICATE OF SERVICE

STATE OF WISCONSIN)
) ss
COUNTY OF DANE)

I make this statement under oath and based on personal knowledge. On this day I caused to be served upon the following persons a copy of Sierra Club's Petition to the United States Environmental Protection Agency In the Matter of the Proposed Revised Operating Permit for the East Kentucky Power Cooperative, Inc. Hugh L. Spurlock Generating Station in Maysville, Kentucky, via Certified Mail, Return Receipt Requested:

Stephen L. Johnson
US EPA Administrator
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Environment and Public Protection Cabinet
Department for Environmental Protection
Division of Air Quality
803 Shenkel Lane
Frankfurt, KY 40601

East Kentucky Power Cooperative, Inc.
Hugh L. Spurlock Generating Station
P.O. Box 707
Winchester, KY 40392-0707

East Kentucky Power Cooperative, Inc.
Hugh L. Spurlock Generating Station
1301 West 2nd Street
Maysville, KY 41056

Dated : April 28, 2008

Erik Schneider

Signed and sworn to before me
This 28th day of April, 2008.

Notary Public, State of Wisconsin
My commission is permanent.

Commonwealth of Kentucky
Environmental and Public Protection Cabinet
Department for Environmental Protection
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601
(502) 573-3382

Final

AIR QUALITY PERMIT
Issued under 401 KAR 52:020

Permittee Name:	**East KY Power Cooperative, Inc.**
Mailing Address:	**P. O. Box 707, Winchester, Kentucky 40392-0707**
Source Name:	**Hugh L. Spurlock Generating Station**
Mailing Address:	**P. O. Box 707, Winchester, Kentucky 40392-0707**
Source Location:	**1301 West 2nd Street, Maysville, KY 41056**
Permit Number:	**V-06-007 Revision 2**
Source A. I. #:	**3004**
Activity #:	**APE20070003**
Review Type:	**TitleV/PSD/Acid Rain/NOx Budget, Const./Oper**
Source ID #:	**21-161-00009**
ORIS Code:	**6041**
Regional Office:	**Ashland** **1550 Wolohan Drive, Suite 1** **Ashland 41102-8942** **606-929-5285**
County:	**Mason**
Application Complete Date:	**December 21, 2007**
Issuance Date:	**July 31, 2006**
Revision Date:	**January 10, 2007, April 18, 2008**
Expiration Date:	**July 31, 2011**

Diana J. Andrews

John S. Lyons, Director
Division for Air Quality

Revised 10/19/05

Exhibit A

TABLE OF CONTENTS

Rev. #	Permit type	Log #, or Activity #	Completed Date	Issuance Date	Summary of Action
Title V Renewal	NSR/PSD	Activity# APE20040001	Jan. 20, 2006	July 31, 2006	Title V permit renewal and significant revision for construction of Unit#4 boiler-turbine-generator
Revision 1	Minor Revision	APE20060003	Aug. 22, 2006	January 10, 2007	Addition of WFSD and WESP on both Units 01& 02
Revision 2	Significant Revision	APE20070003	Dec 21 2007	4/18/08	U.S. EPA Administrator's Order (IV-2006-4)

SECTION A - PERMIT AUTHORIZATION

Pursuant to a duly submitted application the Kentucky Division for Air Quality hereby authorizes the operation and construction of the equipment described herein in accordance with the terms and conditions of this permit. This permit has been issued under the provisions of Kentucky Revised Statutes Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any affected facilities without first submitting a complete application and receiving a permit for the planned activity from the permitting authority, except as provided in this permit or in 401 KAR 52:020, Title V Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by this Cabinet or any other federal, state, or local agency.

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

Emissions Unit 01 - Indirect Heat Exchanger (Unit 1)

Description:

Pulverized coal, dry-bottom, wall-fired boiler, rated 3500 MMBtu/hr with low NOx burners
Number two fuel oil used for startup and stabilization
Control equipment: Electrostatic Precipitator; Selective Catalytic Reduction
Construction commenced before: 1971
New Control equipment: Wet Electrostatic Precipitator, Wet Flow Gas Desulfurization
Construction Commenced after: May 12, 2006

Applicable Regulations:

401 KAR 61:015, Existing indirect heat exchangers with a capacity more than 250 MMBtu per hour and commenced before August 17, 1971;
401 KAR 51:160, NO_x requirements for large utility and industrial boilers, incorporating by reference 40 CFR 96;
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions 40 CFR Parts 72 to 78;
40 CFR Part 64, Compliance Assurance Monitoring.

1. **Operating Limitations**: None

2. **Emission Limitations:**

a) Pursuant to 401 KAR 61:015, Section 4 (1), particulate emissions shall not exceed 0.14 lb/MMBtu based on a three-hour average.

b) Pursuant to 401 KAR 61:015, Section 4 (2), emissions shall not exceed 20 percent opacity based on a six-minute average except that a maximum of 40 percent opacity is allowed for a period not more than six minutes in any 60 minutes.

c) Emissions from an indirect heat exchanger shall not exceed 20 percent opacity based on a six-minute average except during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations.

d) Pursuant to 401 KAR 61:015, Section 1 (3)(e), sulfur dioxide emission shall not exceed 3.0 lb/MMBtu based on a twenty-four-hour average.

3. **Testing Requirements:**

a) In accordance with subsection 4(b), the permittee shall conduct testing for particulates within one year following the issuance of this permit to establish the correlation between opacity and particulate emissions. This testing shall be conducted in accordance with 401 KAR 50:045, Performance Tests, and pursuant to 40 CFR 64.4(c)(1), the testing shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific emissions unit.

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

b) If no additional stack tests are performed pursuant to subsection 4(b), the permittee shall conduct one performance test for particulate emissions within the third year of the term of this permit to demonstrate compliance with the allowable standard.

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 61:005, Section 3, Performance Specification 1 of 40 CFR 60, Appendix B, and 401 KAR 52:020, Section 26, a continuous opacity monitoring (COM) system shall conform to requirements of these sections which include installing, calibrating, operating, and maintaining the continuous monitoring system for accurate opacity measurement. Excluding the startup, shut down, and exempted time periods, if any six-minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate:

i) Accept the concurrent readout from the COM and perform an inspection of the control equipment and make any necessary repairs or;

ii) Determine opacity using reference Method 9 if emissions are visible, inspect the COM and/or the control equipment, and make any necessary repairs. If a Method 9 cannot be performed, the reason for not performing the test shall be documented.

b) Pursuant to 401 KAR 52:020, Section 26, to meet the monitoring requirement for particulate matter, the permittee shall use a COM. Pursuant to 40 CFR 64.4(a)(1) and the CAM plan filed on October 27, 2005, opacity shall be used as an indicator of particulate matter emissions in conjunction with monitoring of the electrostatic precipitator's transformer/rectifier voltage and current levels. Pursuant to 40 CFR Part 64.4(c)(1), testing shall be conducted to establish the level of opacity that will be used as an indicator of particulate matter emissions. The opacity indicator level shall be established at a level that provides reasonable assurance that particulate matter emissions are in compliance when opacity is equal to or less than the indicator level.

i) If any six-minute average opacity (averaged over a period of three hours) value exceeds the opacity indicator level, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs.

ii) If five (5) percent or greater of COM data (data averaged over six-minute periods) recorded in a calendar quarter show excursions above the opacity indicator level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate matter standard while operating at representative conditions. The permittee shall submit a compliance test protocol as required by Section G(a)(17) of the permit before conducting the test. The Division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance Tests.

iii) If primary or secondary voltage or current levels of the transformer/rectifier sets are found to be outside normal ranges, corrective action shall be initiated.

c) Pursuant to 401 KAR 61:005, Section 3 and Performance Specification 2 of Appendix B to 40 CFR 60 or 40 CFR 75, Appendix A, and 401 KAR 52:020, Section 26, continuous emission monitoring systems (CEMS) shall be installed, calibrated, maintained, and operated for measuring sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide emissions. If any 24-hour average sulfur dioxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEMS and make any necessary repairs or take corrective actions as soon as practicable.

d) Pursuant to 401 KAR 61:015, Section 6(1), the sulfur content of solid fuels, as burned shall be determined in accordance with methods specified by the Division.

e) Pursuant to 401 KAR 61:015, Section 6(3), the rate of each fuel burned shall be measured daily and recorded. The heating value and ash content of fuels shall be ascertained at least once per week and recorded. The average electrical output, and the minimum and maximum hourly generation rate shall be measured and recorded daily.

f) Pursuant to 401 KAR 61:005, Section 3(5), the Division may provide a temporary exemption from the monitoring and reporting requirements of 401 KAR 61:005, Section 3, for the continuous monitoring system malfunction, provided that the source owner or operator shows, to the Division's satisfaction, that the malfunction was unavoidable and is being repaired as expeditiously as practicable.

g) Pursuant to 401 KAR 52:020, Section 26, the permittee shall monitor the time between ignition and the time steady state operation of emission unit #1 is achieved.

5. <u>Specific Record Keeping Requirements:</u>

a) Records shall be kept in accordance with 401 KAR 61:005, Section 3(16)(f) and 61:015, Section 6, with the exception that the records shall be maintained for a period of five years.

b) The permittee shall maintain the records of the following:
- i) data collected either by the continuous monitoring systems or as necessary to convert monitoring data to the units of the applicable standard;
- ii) the results of all compliance tests;
- iii) percentage of the COM data (excluding startup, shutdown, and malfunction data) showing excursions above the opacity standard and the opacity indicator level;
- iv) transformer/rectifier primary and secondary voltage and current levels at least once per shift;
- v) the records of the fuel analysis;
- vi) the rate of fuel burned on a daily basis;
- vii) the heating value and ash content on a weekly basis; and
- viii) the average electrical output and the minimum and maximum hourly generation rates on a daily basis.

c) Pursuant to 401 KAR 52:020, Section 26, the permittee shall record the time of ignition; the time steady state operation of emission unit #1 is achieved, and shall calculate and record the elapsed time between the two.

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

6. **Specific Reporting Requirements:**

a) Pursuant to 401 KAR 61:005, Section 3 (16), minimum data requirements, which follow, shall be maintained and furnished in the format specified by the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter.

i) Owners or operators of facilities required to install continuous monitoring systems, or those utilizing fuel sampling and analysis for sulfur dioxide emissions, shall submit for every calendar quarter, a written report of excess emissions, the nature, and cause of the excess emissions if known. The averaging period used for data reporting should correspond to the emission standard averaging period;

ii) For opacity measurements, the summary shall consist of the magnitude in actual percent opacity of six (6) minute averages of opacity greater than the applicable opacity standard for each hour of operation of the facility. Average values may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four (4) equally spaced, instantaneous opacity measurements per minute. Any time period exempted shall be considered before determining the excess average of opacity. Opacity data shall be reported in electronic files only;

iii) A report of the number of excursions (excluding any exempted time periods) above the opacity indicator level, date and time of the excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity indicator level.

iv) For gaseous measurements the summary shall consist of hourly averages in the units of the applicable standard. The hourly averages shall not appear in the written summary, but shall be provided in electronic files only.

v) The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs or adjustments shall be reported. Proof of continuous monitoring system performance is required as specified by the Division whenever system repairs or adjustments have been made.

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

b) Pursuant to 401 KAR 61:015, in the event of start-up, the permittee shall report:
   i) The type of start-up (cold, warm, or hot);
   ii) The reason why the start-up was determined to be cold, warm, or hot (or the conditions that dictated a cold, warm, or hot start-up);
   iii) The elapsed time of (or duration of) the start-up;
   iv) The manufacturer's recommended duration for that type of start-up or alternatively, typical, historical durations for that type of start-up based upon good engineering practices; and

v) Whether or not the duration of the start-up exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the start-up exceeded recommended or typical durations.

7. **Specific Control Equipment Operating Conditions:**

a) Electrostatic Precipitator, Selective Catalytic Reduction system Wet Electrostatic Precipitator, and Wet Flow Gas Desulfurization system shall be operated to maintain compliance with permitted emission limitations, consistence with manufacturer's specifications and / or good operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 02 - Indirect Heat Exchanger (Unit 2)

Description:

Pulverized coal-fired boiler, dry bottom, tangentially-fired rated 5600 MMBtu/hr equipped with low NOx burners
Number two fuel oil used for startup and stabilization
Control equipment: Electrostatic Precipitator, and Selective Catalytic Reduction system
Construction commenced: 1981
New control equipment: Wet Electrostatic Precipitator, and Wet Flow Gas Desulfurization
Construction Commenced after: May 12, 2006

Applicable Regulations:

401 KAR 51:160, NOx requirements for large utility and industrial boilers; incorporating by reference 40 CFR 96;
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions in 40 CFR Parts 72 to 78;
401 KAR 59:015, New Indirect Heat exchangers with more than 250 MMBtu per hour capacity and commenced on or after August 17, 1971;
40 CFR 60 Subpart D, Standards of Performance for fossil-fuel-fired steam generators, for an emissions unit greater than 250 MMBtu/hr and commenced after August 17, 1971;
40 CFR Part 64, Compliance Assurance Monitoring;
40 CFR 52.21, Prevention of significant deterioration of air quality.

1. Operating Limitations:

a) The permittee shall operate emission unit #2 at a maximum heat input not greater than 5600 MMBtu/hr as determined by a weekly average.

b) The average heating value of the coal as burned shall be ascertained at least once per week and recorded The hours of operation and average amount of coal burned (tons/hr) shall also be determined and recorded weekly. Hourly heat rate shall be calculated and recorded weekly.

2. Emission Limitations:

a) Pursuant to 401 KAR 59:015, Section 4(1)(b), particulate emissions shall not exceed 0.1 lb/MMBtu based on a three-hour average.

b) Pursuant to 401 KAR 59:015, Section 4(2), emissions shall not exceed twenty (20) percent opacity based on a six-minute average except a maximum of twenty-seven (27) percent opacity shall be permissible for not more than one (1) six (6) minute period in any sixty (60) consecutive minutes.

c) Emissions from an indirect heat exchanger shall not exceed 20 percent opacity based on a six-minute average except during building a new fire for the period required to bring the boiler up to operating conditions provided the method used is that recommended by the manufacturer and the time does not exceed the manufacturer's recommendations.

d) Pursuant to 401 KAR 59:015, Section 5(1)(b), sulfur dioxide emissions shall not exceed 1.2 lb/MMBtu based on a three-hour average.

e) Pursuant to 401 KAR 59:015, Section 6(1)(c), nitrogen oxides emissions expressed as nitrogen dioxide shall not exceed 0.7 lb/MMBtu based on a three-hour average.

3. Testing Requirements:

a) In accordance with subsection 4(b), the permittee shall conduct testing for particulates within one year following the issuance of this permit to establish the correlation between opacity and particulate emissions. This testing shall be conducted in accordance with 401 KAR 50:045, Performance Tests, and pursuant to 40 CFR 64.4(c)(1), the testing shall be conducted under conditions representative of maximum emissions potential under anticipated operating conditions at the pollutant-specific emissions unit.

b) If no additional stack tests are performed pursuant to subsection 4(b), the permittee shall conduct one performance test for particulate emissions within the third year of the term of this permit to demonstrate compliance with the allowable standard.

4. Specific Monitoring Requirements:

a) Pursuant to 401 KAR 59:015, Section 7, Performance Specification 1 of 40 CFR 60, Appendix B, and 401 KAR 52:020, Section 26, a continuous opacity monitoring (COM) system shall conform to requirements of these sections which include installing, calibrating, operating, and maintaining the continuous monitoring system for accurate opacity measurement. Excluding the startup, shut down, and exempted time periods, if any six-minute average opacity value exceeds the opacity standard, the permittee shall, as appropriate:

i) Accept the concurrent readout from the COM and perform an inspection of the control equipment and make any necessary repairs or;

ii) Determine opacity using reference Method 9 if emissions are visible, inspect the COM and/or the control equipment, and make any necessary repairs. If a Method 9 cannot be performed, the reason for not performing the test shall be documented.

b) Pursuant to 401 KAR 52:020, Section 26, to meet the monitoring requirement for particulate matter, the permittee shall use a COM. Pursuant to 40 CFR 64.4(a)(1) and the CAM plan filed on October 27, 2005, opacity shall be used as an indicator of particulate matter emissions in conjunction with monitoring of the electrostatic precipitator's transformer/rectifier voltage and current levels. Pursuant to 40 CFR Part 64.4(c)(1), testing shall be conducted to establish the level of opacity that will be used as an indicator of particulate matter emissions. The opacity indicator level shall be established at a level that provides reasonable assurance that particulate matter emissions are in compliance when opacity is equal to or less than the indicator level.

i) If any six-minute average opacity (averaged over a period of three hours) value exceeds the opacity indicator level, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs.

ii) If five (5) percent or greater of COM data (data averaged over six-minute periods) recorded in a calendar quarter show excursions above the opacity indicator level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate matter standard while operating at representative conditions. The permittee shall submit a compliance test protocol as required by Section G(a)(17) of the permit before conducting the test. The Division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance Tests.

iii) If primary or secondary voltage or current levels of the transformer/rectifier sets are found to be outside normal ranges, corrective action shall be initiated.

c) Pursuant to 401 KAR 61:005, Section 3 and Performance Specification 2 of Appendix B to 40 CFR 60 or 40 CFR 75, Appendix A, and 401 KAR 52:020, Section 26, continuous emission monitoring systems (CEMS) shall be installed, calibrated, maintained, and operated for measuring sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide emissions. Pursuant to 40 CFR 64.3(d), the nitrogen oxides CEMS shall be used to satisfy CAM requirements. Pursuant to 40 CFR 64.3(d), the sulfur dioxide CEMS shall be used to satisfy CAM requirements when the flue gas desulfurization system is in use.

i) If any 24-hour average sulfur dioxide value exceeds the standard, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and/or the CEMS and make any necessary repairs or take corrective actions as soon as practicable.

ii) If any three-hour average nitrogen oxide value exceeds the standard, the permittee shall as appropriate, initiate an investigation of the cause of the exceedance and/or the CEMS and make any necessary repairs or take corrective actions as soon as practicable.

d) Pursuant to 401 KAR 52:020, Section 26, the permittee shall monitor the time between ignition and the time steady state operation of emission unit #2 is achieved.

5. Specific Record Keeping Requirements:

a) Pursuant to 401 KAR 59:005, Section 3 (4), the owner or operator of the indirect heat exchanger 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; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any malfunction, shutdown, or startup, in the operation of the emissions unit, air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative.

c) The permittee shall compute and record percentage of COM data (excluding startup, shutdown and malfunction data) showing excursions above the opacity standard in each calendar quarter.

d) The permittee shall keep the results of all compliance tests.

e) Pursuant to 401 KAR 52:020, Section 26, the permittee shall record the time of ignition; the time steady state operation of emission unit #2 is achieved, and shall calculate and record the elapsed time between the two.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 59:005, Section 3 (3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install CEM systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

i) The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

ii) All hourly averages shall be reported for sulfur dioxide and nitrogen oxides monitors. The hourly averages shall be made available in the format specified by the Division.

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

iv) The date and time identifying each period during which continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments shall be reported.

b) Pursuant to 401 KAR 59:015, Section 7(7), for the purposes of reports required under 401 KAR 59:005, Section 3(3), periods of excess emissions that shall be reported and defined as follows:

i) Excess emissions are defined as any six (6) minute period during which the average opacity of emissions exceeds twenty (20) percent opacity, except that one (1) six (6) minute average per hour of up to twenty-seven (27) percent opacity need not be reported.

ii) Excess emissions of sulfur dioxide are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable sulfur dioxide emissions standards.

iii) Excess emissions for emissions units using a continuous monitoring system for measuring nitrogen oxides are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable nitrogen oxides emissions standards.

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

c) The permittee shall report the number of excursions (excluding startup, shutdown, malfunction data) above the opacity standard, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity standard in each calendar quarter.

d) Pursuant to 401 KAR 59:015, in the event of start-up, the permittee shall report:
   i) The type of start-up (cold, warm, or hot);
   ii) The reason why the start-up was determined to be cold, warm, or hot (or the conditions that dictated a cold, warm, or hot start-up);
   iii) The elapsed time of (or duration of) the start-up;
   iv) The manufacturer's recommended duration for that type of start-up or alternatively, typical, historical durations for that type of start-up based upon good engineering practices; and
   v) Whether or not the duration of the start-up exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the start-up exceeded recommended or typical durations.

7. **Specific Control Equipment Operating Conditions:**

a) Electrostatic Precipitator, Selective Catalytic Reduction system Wet Electrostatic Precipitator, and Wet Flow Gas Desulfurization system shall be operated to maintain compliance with permitted emission limitations, consistence with manufacturer's specifications and / or good operating practices.

b) Records regarding the maintenance of the control equipments shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 08 Circulating Fluidized Bed Unit #3

Description:

Coal fired Circulating Fluidized Bed (CFB) boiler rating 2,500 MMBtu/hour,
Emission control units: baghouse, dry lime scrubber, and SNCR
No. 2 Fuel Oil used for startup and stabilization
Tire-Derived Fuel (TDF) <=10% coal fuel by weight ratio
Construction date: June 2002

Applicable Regulations:

401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Da, Standards of performance for electric utility steam generating units applicable to an emission unit with a capacity of more than 250 MMBtu/hr and commenced on or after September 19, 1978;
40 CFR 60, Appendix F, Quality Assurance Procedures;
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982;
401 KAR 51:160, NOx requirements for large utility and industrial boilers, incorporating by reference 40 CFR 96;
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions 40 CFR Parts 72 to 78;
40 CFR 63, Subpart B, Requirements for Control Technology Determinations with Major Sources in Accordance with Clean Air Act Sections, Sections 112 (g) and 112(j);
40 CFR 64, Compliance Assurance Monitoring;
40 CFR Part 75, Continuous Emission Monitoring;
401 KAR 63:020, Potentially hazardous matter or toxic substances.

State Only Enforceable Applicable Regulation:

401 KAR 59:016, New Electric Utility Steam Generating Units

1. Operating Limitations:

a) Pursuant to 401 KAR 51:017, the permittee shall install control devices required to meet BACT.

b) Tire-Derived Fuel (TDF) shall not be burned in excess of 10% of coal fuel by weight ratio.

2. Emission Limitations:

a) Pursuant to 401 KAR 59:016, Section 3(1)(b), and 401 KAR 51:017, particulate emissions shall not exceed 0.015 lb/MMBtu heat input based on a three-hour average. Pursuant to 401 KAR 59:016, Section 6(1), compliance with the 0.015 lb/MMBtu emission limitation shall constitute compliance with the 99% reduction requirement contained in 401 KAR 59:016, Section 3(1)(b).

b) Pursuant to 401 KAR 59:016, Section 3(2), emissions from this unit shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent opacity is allowed for not more than one (1) six (6) minute period in any 60 consecutive minutes.

c) Pursuant to 401 KAR 59:016, Section 4(1) and 401 KAR 51:017, sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu based on a twenty-four (24) hour block average. Compliance with the twenty-four (24) hour average shall constitute compliance with the thirty (30) day rolling average contained in 401 KAR 59:016.

d) Pursuant to 401 KAR 51:017, carbon monoxide emissions shall not exceed 0.15 lb/MMBtu based on a thirty (30) day rolling average.

e) Pursuant to 401 KAR 51:017, nitrogen oxides emissions shall not exceed 0.07 lb/MMBtu based on a thirty (30) day rolling average. The NOx emission limit is waived for the specific SNCR optimization study activity as detailed in Section D (8 and 9). Should the optimization study indicate that 0.07 lb/MMBtu is unachievable, the NOx emissions rate shall be the optimized rate up to a maximum of 0.10 lbs/MMBtu.

f) Pursuant to 401 KAR 51:017, VOC emissions shall not exceed 0.0036 lb/MMBtu based on a thirty (30) day rolling average.

g) Pursuant to 401 KAR 51:017, mercury emissions shall not exceed 0.00000265 lb/MMBtu based on a quarterly average.

h) Pursuant to 401 KAR 51:017, fluoride emissions shall not exceed 0.0000466 lb/MMBtu based on a thirty (30) day rolling average.

i) Pursuant to 401 KAR 51:017, lead emissions shall not exceed 0.0000063 lb/MMBtu based on a quarterly average.

j) Pursuant to 401 KAR 51:017, beryllium emissions shall not exceed 0.0000146 lb/MMBtu based on a quarterly average.

k) Pursuant to 401 KAR 51:017, sulfuric acid mist emissions shall not exceed 0.005 lb/MMBtu based on a thirty (30) day average.

l) Pursuant to 401 KAR 59:016, Section 6(3), particulate matter and nitrogen oxides emission standards apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standard under Section 4 applies at all times except during periods of startup, shutdown, or emergency conditions per 401 KAR 59:016 Section 6.

m) Pursuant to 40 CFR. 63.43(d), case-by-case MACT determination for the Unit # 3 Boiler, shall not exceed the following hazardous air pollutants (HAP) emission limitations:

HAP	Emissions Limitation (lb/MMBtu)
VOC	0.0036
Mercury	0.00000265
Hydrogen Chloride	0.0035
Hydrogen Fluoride	0.00047
Beryllium	0.0000146
Lead	0.0000063
Metal HAPS (as PM)	0.015

3. Testing Requirements:

a) Pursuant to 401 KAR 50:055, Section 2, the permittee shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility. Opacity data from the Continuous Opacity Monitor (COM) during the performance test for particulate shall be correlated with the particulate emissions rate to establish an opacity indicator level pursuant to Condition 4.b below.

b) If no additional stack tests are performed pursuant to Condition 4.b, the permittee shall conduct a performance test for particulate emissions within the third year after demonstrating compliance with the allowable standard.

c) The permittee shall determine the opacity of emissions from the stack by EPA Reference Method 9 weekly, or more frequently if requested by the Division.

d) See Section D

e) Case-by-Case MACT
Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination, and 40 CFR.70.6(c), the permittee shall demonstrate compliance with the applicable emissions limitations for the following HAPs:

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

HAP	Emissions Limitation	Compliance Method
VOC (VOC HAPs)	0.0036 lb/MMBtu	Method 25A
Mercury	0.00000265 lb/MMBtu	Method 29
Hydrogen Chloride	0.0035 lb/MMBtu	Method 26A
Hydrogen Fluoride	0.00047 lb/MMBtu	Method 26A
Beryllium	0.0000146 lb/MMBtu	Method 29
Lead	0.0000063 lb/MMBtu	Method 29
Metal HAPs (as PM)	0.015 lb/MMBtu	Method 5

f) Pursuant to 40 CFR 63.43(g)(2)(ii) case-by case MACT determination, and 40 CFR 70.6(c), the permittee shall demonstrate compliance with these emissions limitations within 60 days after achieving the maximum production rate at which the facility will be operated, but not later than 180 days after initial startup of the emissions unit. See Section G(d)5

g) During the initial compliance test, the permittee shall take a sample of the fuel "as fired" and analyze it to determine the HAP content in the fuel. This information shall be used to establish a correlation between the sample's HAP content and HAP emissions for monitoring purposes. The permittee shall demonstrate compliance with these emission limits each year to validate the correlation between grab samples HAP content and HAP emissions. After three years of demonstrating compliance and the correlation between the samples and emissions, the permittee may petition the Division to use the grab samples as a surrogate for compliance testing.

h) The permittee shall perform initial testing with the appropriate U.S. EPA test method for SAM to establish correlation with sulfur dioxide emission readings and the limestone injection rate to sulfuric acid mist (SAM) emissions. Lime injection rate and SO_2 CEM readings are the indicators of continuing SAM compliance.

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7 and 401 KAR 59:005, Section 4, the permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, carbon monoxide emissions, and either oxygen or carbon dioxide emissions. Oxygen or carbon dioxide shall be monitored at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The owner or operator shall ensure the continuous emission monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4. Compliance with the Continuous Emission Monitoring provisions of 40CFR 75 will constitute compliance with the monitoring requirements of 401 KAR 59:016.

b) Pursuant to 401 KAR 52:020, Section 26, 401 KAR59:016, Section 7(1), to meet the compliance assurance monitoring requirement for particulate, the permittee shall use a continuous opacity monitor (COM). The opacity indicator level determined pursuant to Condition 3.a above, shall be established at a level that provides reasonable assurance that PM emissions are in compliance when opacity is equal to or less than the indicator. Excluding the startup, shut down, and once per hour exemption periods, if any six minute average opacity (averaged over a period of 3 hours) value exceeds the opacity trigger level, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the COM system and make any necessary repairs. If five (5) percent or greater of COM data (excluding startup, shut down, and malfunction periods, data averaged over a three hour period) recorded in a calendar quarter show excursions above the opacity trigger level, the permittee shall perform a stack test in the following calendar quarter to demonstrate compliance with the particulate standard while operating at representative conditions. The permittee shall submit a compliance test protocol as required by Section G (a)(19) of this permit before conducting the test. The Division may waive this testing requirement upon a demonstration that the cause(s) of the excursions have been corrected, or may require stack tests at any time pursuant to 401 KAR 50:045, Performance Tests.

c) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7(1), the permittee shall use a continuous opacity monitor (COM) to meet the monitoring requirements for opacity. The permittee shall perform a qualitative visual observation of the opacity of emissions from the stack on a daily basis and maintain a log of the observations. If visible emissions from the stack are seen, the permittee shall determine the opacity of emissions by Reference Method 9, or by accepting the concurrent read out from the COM and instigating an inspection of the control equipment and making any necessary repairs. If no visible emissions, which would trigger Reference Method 9 determinations or equipment repairs, are observed during any six consecutive week period, the frequency of observation may be reduced to weekly. Observations shall revert to daily if visible emissions, which would trigger Reference Method 9 determinations or equipment repairs, are observed during any weekly observation. Daily observations shall continue until such time that no visible emissions, which would trigger Reference Method 9 determinations or equipment repairs, are observed during any three consecutive week period.

d) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7(2), to meet the compliance assurance monitoring requirement for sulfur dioxide, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 24-hour block average sulfur dioxide value exceeds that standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

e) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7(3), to meet the compliance assurance monitoring requirement for nitrogen oxides, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 30 day rolling average nitrogen oxide value exceeds the standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or CEM system and make any necessary repairs or take any corrective actions as soon as practicable.

f) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 51:017, and 401 KAR 59:016, Section 7(2), the permittee shall monitor sulfur dioxide emissions at the outlet of the dry lime scrubber using a continuous emissions monitoring system.

g) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7(3), to meet the continuous monitoring requirement for carbon monoxide, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 30 day rolling average carbon monoxide value exceeds the standard, the permittee shall, as appropriate, initiate an inspection of the unit and/or CEM system and make any necessary repairs or take any corrective actions as soon as practicable. The carbon monoxide CEM system shall be operated and maintained in accordance with Performance Specification 4 of Appendix B to 40 CFR 60 filed by reference in 401 KAR 50:015.

h) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7(5), all the continuous emission monitoring systems shall be operated and data shall be recorded during all periods of operation of the emissions unit including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

i) Pursuant to 401 KAR 52:020, Section 26, and 401 KAR 59:016, Section 7(6), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, the permittee shall obtain emission data by using other monitoring systems as approved by the Division or the reference methods as described in 401 KAR 59:016, Section 7(8) to provide emission data for a minimum of eighteen hours in at least twenty-two out of thirty successive boiler operating days.

j) Pursuant to 401 KAR 59:016, Section 7(9), the following procedures shall be used to conduct monitoring system performance evaluations and calibration checks as required under 401 KAR 59:005, Section 4(3).

i) Reference Method 6, 7, or 10 as applicable shall be used for conducting performance evaluations of sulfur dioxide, nitrogen oxides and carbon monoxide continuous emission monitoring systems.

ii) Sulfur dioxide or nitrogen oxides, as applicable, shall be used for preparing calibration mixtures under Performance Specification 2 of Appendix B to 40 CFR 60 filed by reference in 401 KAR 50:015.

iii) The span value for the continuous monitoring system for measuring opacity shall be between sixty (60) and eighty (80) percent and the span value for the continuous monitoring system for measuring nitrogen oxides shall be as specified in 40 CFR 75, Appendix A.

iv) The span value for the continuous monitoring system for measuring sulfur dioxide the outlet of the control device shall be 50 percent of the maximum estimated hourly potential emissions of the fuel fired or span value specified in 40 CFR 75, Appendix A.

k) The permittee shall take a grab sample of the fuel "as fired" to the CFB on a quarterly basis. The samples taken on a quarterly basis shall be analyzed to determine beryllium content. The samples taken on a quarterly basis shall also be analyzed to determine the applicable hazardous air pollutant content. This data, along with the baseline data established during the initial compliance test, shall be used to demonstrate compliance with the emission limits for these pollutants. Depending on the results of the quarterly tests, additional steps may be required to ensure that applicable hazardous air pollutant content emission limits are not exceeded.

l) The permittee shall monitor and record the TDF tonnage and 10% tire to coal ratio for fuel usage on a monthly basis.

m) CAM Requirements

The permittee shall use Sulfur Dioxide (SO2) and Nitrogen Oxides (NOx) Continuous Emissions Monitors (CEMs) as continuous compliance determination methods to preclude applicability of 40 CFR 64 for those specific parameters, and to demonstrate compliance with Best Available Control Technology (BACT) limits contained in this permit.

i) The permittee shall conduct the monitoring and fulfill the other obligations specified in 40 C.F.R. §§ 64.7 through 64.9.

ii) Pursuant to 40 CFR 64.6, the table below shows the monitoring approach for PM.

CAM Requirement	PM/PM_{10} limits
General Requirements	0.015 lb/MMBtu filterable particulates, 20% Opacity
Monitoring Methods and Location	Initial Source Test & (1) installation of a COM at outlet of the baghouse and monitoring of the baghouse pressure drop and other relevant parameters identified during initial testing or (2) visual observation of plume from stack
Indicator Range	(1) Initial source testing to establish COM and equipment parameter indicator ranges, including the baghouse pressure drop, as appropriate or (2) Initial source testing to establish compliance with the PM limit at 20% opacity. The permittee must conduct daily stack observations. If visible emissions are seen, the permittee must conduct a Method 9 observation to determine the opacity of the emissions or shall accept the concurrent read-out from the COM.
Data Collection Frequency	(1) COM and control device operating parameters or (2) daily observations
Averaging Period	(1) Opacity – 6 minute averages or (2) Visible Emission Surveys – 6 minutes
Recordkeeping	COM data system records and control device parameters will be maintained for a period of 5 years. Visible observation records and method 9 observations will be kept in a designated logbook and maintained for a period of 5 years.
QA/QC	COM will be maintained and operated in accordance with 401KAR 59:005 / 40CFR 60 Appendix B and other requirements as applicable. Baghouse monitored parameters will be maintained and operated in accordance with manufacturer recommendations; or records of Method 9 certifications will be maintained

Case-by- Case MACT

Pursuant to 63.43(g) case-by-case MACT determination, the permittee shall conduct the following monitoring to assure compliance with the applicable requirements:

HAP	**Emissions Limitation lb/MMBtu**	**Monitoring Method**
VOC (VOC HAPs)	0.0036	The continuous compliance monitoring method used to assess compliance with the carbon monoxide emission limitation shall be used as an indicator of good combustion practices. Compliance with the carbon monoxide emission limitation assures compliance with the VOC (VOC HAP) emission limit.
Mercury	0.00000265	The permittee shall take a sample of fuel "as fired" to the boiler on a quarterly basis. The samples taken on a quarterly basis shall be analyzed to determine mercury content. Emissions shall be estimated based on the emission correlations established during the most recent stack test. The continuous compliance monitoring method used to assess compliance with the carbon monoxide emission limitation shall be used as an indicator of good combustion practices. The continuous compliance monitoring method used to assess compliance with the sulfur dioxide emission limitations shall also be used as an indicator or the proper dry lime scrubber operational procedures. Compliance with the carbon monoxide and sulfur dioxide emission limitations assures compliance with the mercury emission limit.
Hydrogen Chloride	0.0035	The continuous compliance monitoring method used to assess compliance with the sulfur dioxide emission limitations shall be used to assure compliance with the hydrogen chloride emission limit. Compliance with the sulfur dioxide emission limitations assures compliance with the hydrogen chloride emissions limit.
Hydrogen Fluoride	0.00047	The continuous compliance monitoring method used to assess compliance with the sulfur dioxide emission limitations shall be used to assure compliance with the hydrogen fluoride emission limit. Compliance with the sulfur dioxide emission limitations assures compliance with the hydrogen fluoride emissions limit.
Lead	0.0000063	Same as beryllium

HAP	Emissions Limitation Lb/MMBtu	Monitoring Method
Beryllium	0.0000146	The permittee shall take a sample of fuel "as fired" to the coal-fired boiler on a quarterly basis. The samples taken on a quarterly basis shall be analyzed to determine beryllium. Emissions shall be estimated based on the emission correlations established during the most recent stack test. [The continuous compliance monitoring method used to assess compliance with the PM emission limitations shall be used to assure compliance with the beryllium emission limit as an indicator of proper operation and removal of beryllium from the exhaust stream.]
Metal HAPs	0.015	The continuous compliance monitoring method used to assess compliance with the PM emission limitations shall be used to assure compliance with the metal HAPs emission limit as an indicator of proper operation and removal of metal HAPs from the exhaust stream. Compliance with the PM emission limitation assures compliance with the metal HAPs emissions limit.

n) Pursuant to 40 CFR 63.43 (g)(2)(ii), case-by-case MACT determination, 40 CFR 70.6(a)(3)(i)(B), and 40 CFR 64.6(c)(1), the permittee shall conduct a compliance demonstration each year to validate the correlation between the coal samples HAP content and HAP emissions. The test procedure shall consist of taking grab samples of coal "as-fired" concurrent with the compliance demonstration to correlate the HAP content of coal with the HAP emissions. The coal samples shall be analyzed for HAP content and the correlation with the HAP emissions shall be established based on the analyzed HAP content and stack emissions.

o) Pursuant to 401 KAR 52:020, Section 26, the permittee shall monitor the time between ignition and the time steady state operation of emission unit #3 is achieved.

p) For sulfuric acid mist, the permittee shall utilize the SO2 CEMS and monitor the rate of limestone injection in conjunction with the initial source test to establish excursion levels.

5. **Specific Record Keeping Requirements:**

a) Pursuant to 401 KAR 59:005, Section 3(4), the owner or operator of the CFB 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; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection.

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

b) Pursuant to 401 KAR 59:005, Section 3(2), the owner or operator of this unit shall maintain the records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility, any malfunction of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative.

c) The permittee shall compute and record percentage of the COM data (excluding startup, shut down, and malfunction data) showing excursions above the opacity trigger level in each calendar quarter.

d) The permittee shall maintain the results of all compliance tests.

e) Case-by-Case MACT

i) Pursuant to 40 CFR 63.43(g)(2)(ii), the permittee shall keep quarterly records of the sample's HAP analyses. The permittee shall keep these records according to the general recordkeeping requirements specified in Section F.1. and F.2. of this permit.

ii) Pursuant to 40 CFR 63.43(g)(2)(ii), the permittee shall record continuously the SO2 emission rate at the outlet of the dry lime scrubber using the CEM system.

iii) Pursuant to 40 CFR 63.43(g)(2)(ii), the permittee shall record continuously the opacity of visual emissions at the outlet of the baghouse using the COM system.

iv) Pursuant to 40 CFR 63.43(g)(2)(ii), the permittee shall record continuously the carbon monoxide emission rate using the CEM system.

f) On a daily basis, the permittee shall record the TDF usage for fuel and the coal fuel/weight ratio, when TDF is used as fuel.

g) Pursuant to 401 KAR 52:020, Section 26, the permittee shall record the time of ignition; the time steady state operation of emission unit #3 is achieved, and shall calculate and record the elapsed time between the two.

h) The permittee shall record the limestone injection rates and the SO_2 CEMS data.

6. <u>Specific Reporting Requirements:</u>

a) Pursuant to 401 KAR 59:005, Section 3(3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division for Air Quality. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) All hourly averages shall be reported for sulfur dioxide, nitrogen oxides and carbon monoxide monitors. The hourly averages shall be made available in the format specified by the Division for Air Quality.

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

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

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

6) For sulfur dioxide and nitrogen oxides, all information listed in 401 KAR 59:016, Section 9(2)(a-i) shall be reported for each twenty-four (24) hour period.

7) If the minimum quantity of emission data as required by 401 KAR 59:016, Section 7(6)(a-e) is not obtained for any thirty successive boiler operating days, the permittee shall report all the information listed in 401 KAR 59:016, Section 9(3) for that thirty day period.

8) If any sulfur dioxide standards as specified in 401 KAR 59:016, Section 4(a and b) are exceeded during emergency conditions because of control system malfunction, the permittee shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(4).

9) For any periods for which opacity, sulfur dioxide, nitrogen oxides or carbon monoxide emissions data are not available, the permittee shall submit a signed statement pursuant to 401 KAR 59:016, Section 9(6) indicating if any changes were made in the operation of the emission control system during the period of data unavailability. Operations of control system and emissions unit during periods of data unavailability are to be compared with operation of the control system and emissions unit before and following the period of data unavailability.

10) The permittee shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(7).

11) Pursuant to 401 KAR 59:016, Section 9(8), for the purposes of the reports required under 401 KAR 59:005, Section 4, periods of excess emissions are defined as all six (6) minute periods during which the average opacity exceeds the applicable opacity standards as specified in Subsection 2 of this section. Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter.

b) Pursuant to 401 KAR 59:005, Section 3(3), the permittee shall report the number of excursions (excluding startup, shut down, malfunction data) above the opacity trigger level, date and time of excursions, opacity value of the excursions, and percentage of the COM data showing excursions above the opacity trigger level in each calendar quarter to the Division Regional Office.

CAM Requirements

c) Pursuant to 40 C.F.R. §64.9(a) the permittee shall report the following information according to the general reporting requirements specified in Section F.5. of this permit:

i. Number of exceedances or excursions;
ii. Duration of each exceedance or excursion;
iii. Cause of each exceedance or excursion;
iv. Corrective actions taken on each exceedance or excursion;
v. Number of monitoring equipment downtime incidents;
vi. Duration of each monitoring equipment downtime incident;
vii. Cause of each monitoring equipment downtime incident;
viii. Description of actions taken to implement a quality improvement plan for operating and monitoring, and upon completion of the quality improvement plan, documentation that the plan was completed and reduced the likelihood of similar excursions or exceedances and downtimes.

d) Pursuant to 401 KAR 52:020, Section 26, in the event of start-up, the permittee shall report:

1) The type of start-up (cold, warm, or hot);
2) The reason why the start-up was determined to be cold, warm, or hot (or the conditions that dictated a cold, warm, or hot start-up);
3) The elapsed time of (or duration of) the start-up;
4) The manufacturer's recommended duration for that type of start-up or alternatively, typical, historical durations for that type of start-up based upon good engineering practices; and
5) Whether or not the duration of the start-up exceeded the manufacturer's recommendation or typical, historical durations, and if so, an explanation of why the start-up exceeded recommended or typical durations.

e) Pursuant to 401 KAR 52:020, the permittee shall utilize the limestone injection rate, the SO_2 CEMS data, and the correlation established during initial source testing to calculate and report sulfuric acid mist (SAM) emissions quarterly to the Division's Regional Office.

7. Specific Control Equipment Operating Conditions:

a) The CFB, baghouse, SNCR, and dry lime scrubber shall be operated to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices. Compliance with this condition for particulate matter is in accordance with the CAM submittal for this unit.

b) Records regarding the maintenance of the control equipment shall be maintained.

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

c) See Section E for further requirements.

d) Case-by-Case MACT

Pursuant to 40 CFR §63.43(d), the permittee shall install and operate the following control technology to meet the case-by-case MACT emission limitations while the emission unit is in operation:

HAP	Control Technology
Mercury	Selective non-catalytic reduction (SNCR), dry lime scrubber, baghouse
Beryllium, Lead	Baghouse
Acid Gases (Hydrogen Chloride and Hydrogen Fluoride)	Dry Scrubber and Baghouse
Metals (Metal HAPs)	Baghouse

e) **Control Equipment Operating Conditions for the dry lime scrubber**:

Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination, 40 CFR and 40 CFR 64.6(c)(2), the permittee shall monitor SO_2 emissions continuously using the CEM system. Compliance with the SO_2 emissions limitation assures proper operation of the dry lime scrubber.

f) **Control Equipment Operating Conditions for the baghouse**:

Pursuant to 40 CFR 63.43(g)(2)(ii), case-by-case MACT determination, 40 CFR and 40 CFR 64.6(c)(2), the permittee shall maintain the opacity of visual emissions to less than 20 % as measured by the COM system. Compliance with the opacity limitation assures proper operation of the baghouse.

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

Emissions Unit 17 Circulating Fluidized Bed Unit #4

Description:

Coal fired Circulating Fluidized Bed (CFB) boiler rating 2800 MMBtu/hr (or 300 MWh)
Emissions control units: Baghouse, dry lime scrubber, and SNCR
Tire-Derived Fuel (TDF), <= 10% coal fuel by weight ratio
ASTM Grade No.2-DS15 fuel oil, used for startup and stabilization
Construction Commence Date: April 2006

Applicable Regulations:

401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Da, Standards of performance for electric utility steam generating units applicable to an emission unit with a capacity of more than 250 MMBtu/hr and commenced on or after September 19, 1978;
401 KAR 51:160, NO_x requirements for large utility and industrial boilers; incorporating by reference 40 CFR 96;
401 KAR 52:060, Acid rain permits, incorporating by reference the Federal Acid Rain provisions as codified in 40 CFR Parts 72 to 78;
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982;
40 CFR Part 64, Compliance Assurance Monitoring (for NOx, PM/PM_{10}, and SO_2);
40 CFR Part 75, Continuous Emission Monitoring;
401 KAR 63:020, Potentially hazardous matter or toxic substances.

State Only Enforceable Applicable Regulation:

401 KAR 59:016, New Electric Utility Steam Generating Units

1. Operating Limitations:

Pursuant to 401 KAR 51:017, the permittee shall install all control devices selected required to meet BACT.

- BACT for PM/PM_{10} is Pulse Jet Fabric Filter.
- BACT for CO is good combustion control.
- BACT for H_2SO_4 mist is a Dry Scrubber and Limestone Injection.
- BACT for fluorides (as HF) is a PJFF and Dry Scrubber.
- BACT for NO_x is a CFB and SNCR.
- BACT for SO_2, is a CFB with dry lime scrubber.
- Only ASTM Grade No.2-DS15 fuel oil, with a sulfur content not to exceed 15 ppm shall be used for startup and stabilization.
- Tire-Derived Fuel (TDF) shall not exceed 10% coal fuel by weight ratio shall be burned.

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

2. **Emission Limitations:**

a) Pursuant to 401 KAR 59:016, Section 3(1)(b), and 401 KAR 51:017, particulate matter (PM, filterable) emissions shall not exceed 0.009 lb/MMBtu based on a 30 day rolling average of the data from the PM CEM, and total particulates (filterable and condensable PM/PM_{10}) shall not exceed 0.012 lb/MMBtu based on a 3 hour performance test. In order to ensure the validity of the NAAQS and increment consumption modeling, PM_{10} emissions shall not exceed 84 lb/hr on a twenty four-block average. Pursuant to 401 KAR 59:016, Section 6(1), compliance with the 0.009 lb/MMBtu (filterable) emission limitation shall constitute compliance with the 99% reduction requirement contained in 401 KAR 59:016, Section 3(1)(b).

b) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.42Da(c), filterable particulate emissions shall not exceed 0.015 lb/MMBtu of heat input based on 3 hour average. Compliance shall be determined using procedures set forth in 40 CFR 60.48 Da.

c) Pursuant to 401 KAR 59:016, Section 3(2), emissions from this unit shall not exceed twenty (20) percent opacity based on a six-minute average except that a maximum of twenty-seven (27) percent is allowed for not more than one (1) six (6) minute per hour.

d) Pursuant to 401 KAR 59:016, Section 4(1) and 401 KAR 51:017, sulfur dioxide (SO2) emissions shall not exceed 0.15 lb/MMBtu on a 24-hour block average. Compliance with the limit shall be demonstrated by continuous emissions monitoring (CEMS). In order to ensure the validity of the NAAQS and increment consumption modeling, sulfur dioxide emissions shall not exceed 504 lb/hr based on a twenty-four (24) hour block average. Compliance with the twenty-four (24) hour average shall constitute compliance with the thirty (30) day rolling average contained in 401 KAR 59:016.

e) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.43Da(i), sulfur dioxide emissions shall not exceed 1.4 lb/MWh gross energy output, based on a thirty (30) day rolling average. Compliance shall be determined using procedures set forth in 40 CFR 60.48 Da. Pursuant to 401 KAR 59:016, Section 4, compliance with this limit shall constitute compliance with the 70% reduction requirement contained in 401 KAR 59:016, Section 4(1)(b).

f) Pursuant to 401 KAR 51:017, carbon monoxide (CO) emissions shall not exceed 0.10 lbs/MMBtu based on a thirty day rolling average. Compliance with the limits shall be demonstrated by continuous emissions monitoring (CEM). In order to ensure the validity of the NAAQS and increment consumption modeling, CO emissions shall not exceed 420 lb/hr on a eight hour block average.

g) Pursuant to 401 KAR 51:017, nitrogen oxides emissions shall not exceed 0.07 lb/MMBtu on a 30-day rolling average. Compliance with the limits shall be demonstrated by continuous emissions monitoring (CEMS). In order to ensure the validity of the NAAQS and increment consumption modeling, nitrogen oxides emissions shall not exceed 280 lb/hr based on a thirty (30) day block average. The NO_X emission limit is waived for the specific SNCR optimization study activity as detailed in Section D (6 and 7). Should the optimization study indicate that 0.07 lbs/MMBtu is unachievable, then a significant revision to the permit will be required. Under no case will the revised limit be greater than 0.09 lbs/MMBtu.

h) Pursuant to 401 KAR 60:005, Section 3(1)(c) and 40 CFR 60.44Da(e), nitrogen oxides emissions, (expressed as NO_2) shall not exceed 1.0 lb/MWh gross energy output, based on a 30-day rolling average. Compliance shall be determined using procedures set forth in 40 CFR 60.48 Da Pursuant to 401 KAR 59:016, Section 5, compliance with this limitation shall constitute compliance with the 65% reduction requirement contained in 401 KAR 59:016, Section 5(2)(c).

i) Pursuant to 401 KAR 51:017, VOC emissions shall not exceed 0.002 lb/MMBtu based on three (3) hour rolling average. Compliance with this limit shall be demonstrated by compliance with Subsection 2(f) above. In order to ensure the validity of the NAAQS and increment consumption modeling, VOC emissions shall not exceed 6 lb/hr on a three hour block average.

j) Pursuant to 40 CFR 60.45Da, mercury emissions shall not exceed 21 x 10-6 lbs/MWh (Gross output) based on a consecutive twelve (12) month rolling average when burning only coal. If the unit burns Tire Derived fuel, the permitted mercury must meet the reduced allowable calculated using Equation 1 of 40 CFR 60.45Da. Compliance shall be determined using the procedures set forth in 40 CFR 60.48 Da.

k) Pursuant to 401 KAR 51:017, fluoride emissions shall not exceed 0.000047 lb/MMBtu based on a three hour rolling average. In order to ensure the validity of the NAAQS and increment consumption modeling, fluoride emissions shall not exceed 1.32 lb/hr on a three hour block average.

l) Pursuant to 401 KAR 51:017, sulfuric acid mist emissions shall not exceed 0.005 lb/MMBtu based on a three-hour average. In order to ensure the validity of the Class I visibility modeling, Sulfuric acid mist emissions shall not exceed 14 lb/hr on a three hour block average.

m) Pursuant to 401 KAR 63:020, the use of good combustion controls, baghouse, dry lime scrubber, and SNCR shall be used for the control of toxic substances.

n) Compliance with emission limits in Subsections (a), (d), (f) and (l) shall constitute compliance with 401 KAR 63:020 with respect to toxic substances.

o) Pursuant to 401 KAR 59:016 Section 6(3), PM and NOx emission standards apply at all times except during periods of startup, shutdown or malfunction. The sulfur dioxide emission standard under Section 4 applies at all times except for periods of startup, shutdown or emergency, pursuant to 401 KAR 59:016 Section 6. Pursuant to 401 KAR 51:017, the owner or operator shall utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of, such events.

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

3. **Testing Requirements:**

a) Pursuant to 401 KAR 50:055, Section 2, the permittee shall demonstrate compliance with the applicable emission standards within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility.

b) During the initial compliance test, the permittee shall take a sample of the fuel "as fired" and analyze it using ASTM methods to determine the fluoride content in the fuel. This information shall be used to establish a correlation between the sample's fluoride content and fluoride emissions for monitoring purposes. The permittee shall demonstrate compliance with these emission limits each year to validate the correlation between coal samples and fluoride emissions. After three years of demonstrating compliance and the correlation between the samples and emissions, the permittee may petition the Division to use the grab samples as a surrogate for compliance testing.

c) See Section D

4. **Specific Monitoring Requirements:**

a) Pursuant to 401 KAR 60:005, Section 3(1)(c); 401 KAR 52:020, Section 26; 401 KAR 59:016, Section 7; and 401 KAR 59:005, Section 4, the permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, carbon monoxide emissions, mercury, particulate matter and either oxygen or carbon dioxide emissions. Oxygen or carbon dioxide shall be monitored at each location where sulfur dioxide or nitrogen oxides emissions are monitored. The owner or operator shall ensure the continuous emission monitoring systems are in compliance with the requirements of 401 KAR 59:005, Section 4. Compliance with the Continuous Emission Monitoring provisions of 40 CFR 75 will constitute compliance with the monitor requirements of 401 KAR 59:016.

b) Pursuant to 401 KAR 52:020, Section 26, and 401 KAR59:016, Section 7(1), to meet the compliance assurance monitoring requirement for particulate matter, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 3-hour or 30 day average value exceeds that standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

c) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7(1), the permittee shall use a continuous opacity monitor (COM). The permittee shall perform a qualitative visual observation of the opacity of emissions from the stack on a daily basis and maintain a log of the observations. If visible emissions from the stack are seen, the permittee shall determine the opacity of emissions by Reference Method 9, or by accepting the concurrent read out from the COM and instigating an inspection of the control equipment and making any necessary repairs. If no visible emissions, which would trigger Reference Method 9 determinations or equipment repairs, are observed during any six consecutive week period, the frequency of observation may be reduced to weekly. Observations shall revert to daily if visible emissions, which would trigger

Reference Method 9 determinations or equipment repairs, are observed during any weekly observation. Daily observations shall continue until such time that no visible emissions, which would trigger Reference Method 9 determinations or equipment repairs, are observed during any three consecutive week period.

d) Pursuant to 401 KAR 52:020, 401 KAR 59:016, Section 7(2) and 40 CFR 75.2, to meet the continuous monitoring requirement for sulfur dioxide, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 24-hour block average sulfur dioxide value exceeds that standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the CEM system and make any necessary repairs as soon as practicable.

e) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 59:016, Section 7(3) and 40 CFR 75.2, to meet the continuous monitoring requirement for nitrogen oxides, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 30 day rolling average nitrogen oxide value exceeds the standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or CEM system and make any necessary repairs or take any corrective actions as soon as practicable.

f) Pursuant to 401 KAR 52:020, Section 26, 401 KAR 51:017, and 401 KAR 59:016, Section 7(2), the permittee shall monitor sulfur dioxide emissions at the outlet of the dry lime scrubber using a continuous monitoring system.

g) Pursuant to 401 KAR 52:020, Section 26, and 401 KAR 59:016, Section 7(3), to meet the continuous monitoring requirement for carbon monoxide, the permittee shall use a continuous emission monitor (CEM). Excluding the startup and shut down periods, if any 30 day rolling average carbon monoxide value exceeds the standard, the permittee shall, as appropriate, initiate an inspection of the unit and/or CEM system and make any necessary repairs or take any corrective actions as soon as practicable. The carbon monoxide CEM system shall be operated and maintained in accordance with Performance Specification 4 of Appendix B to 40 CFR 60 filed by reference in 401 KAR 50:015.

h) Pursuant to 401 KAR 52:020, Section 26 and 40 CFR 60.49Da(p), to meet the continuous monitoring requirements for mercury the permittee shall use a mercury CEMs.

i) Pursuant to 401 KAR 52:020, Section 26, and 401 KAR 59:016, Section 7(5), all the continuous emission monitoring systems shall be operated and data shall be recorded during all periods of operation of the emissions unit including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

j) Pursuant to 401 KAR 52:020, Section 26, and 401 KAR 59:016, Section 7(6), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, the permittee shall obtain emission data by using other monitoring systems as approved by the Division or the reference methods as described in 401 KAR 59:016, Section 7(8) to provide emission

e) Pursuant to 401 KAR 52:020, Section 26, the permittee shall record the time of ignition; the time steady state operation of emission unit #4 is achieved, and shall calculate and record the elapsed time between the two.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 59:005, Section 3(3), minimum data requirements which follow shall be maintained and furnished in the format specified by the Division. Owners or operators of facilities required to install continuous monitoring systems shall submit for every calendar quarter a written report of excess emissions (as defined in applicable sections) to the Division for Air Quality. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information:

1) The magnitude of the excess emission computed in accordance with the 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) All hourly averages shall be reported for sulfur dioxide, nitrogen oxides, particulate and carbon monoxide monitors. The hourly averages shall be made available in the format specified by the Division for Air Quality.

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

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

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

6) For sulfur dioxide and nitrogen oxides, all information listed in 401 KAR 59:016, Section 9(2)(a-i) shall be reported for each twenty-four (24) hour period.

7) If the minimum quantity of emission data as required by 401 KAR 59:016, Section 7(6)(a-e) is not obtained for any thirty successive boiler operating days, the permittee shall report all the information listed in 401 KAR 59:016, Section 9(3) for that thirty day period.

8) If any sulfur dioxide standards as specified in 401 KAR 59:016, Section 4(a and b) are exceeded during emergency conditions because of control system malfunction, the permittee shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(4).

9) For any periods for which opacity, sulfur dioxide, nitrogen oxides or carbon monoxide emissions data are not available, the permittee shall submit a signed statement pursuant to 401 KAR 59:016, Section 9(6) indicating if any changes were made in the operation of the emission control system during the period of data unavailability. Operations of control system and emissions unit during periods of data unavailability are to be compared with operation of the control system and emissions unit before and following the period of data unavailability.

10) The permittee shall submit a signed statement including all information as described in 401 KAR 59:016, Section 9(7).

11) Pursuant to 401 KAR 59:016, Section 9(8), for the purposes of the reports required under 401 KAR 59:005, Section 4, periods of excess emissions are defined as all six (6) minute periods during which the average opacity exceeds the applicable opacity standards as specified in Subsection 2 of this section. Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter.

12) Pursuant to 40 CFR §60. 51Da (g), mercury emissions data shall be reported quarterly to the Division's Regional Office.

b) CAM Requirements

Pursuant to 40 C.F.R. §64.9(a) the permittee shall report the following information according to the general reporting requirements specified in Section F.5. of this permit:

1) Number of exceedances or excursions;
2) Duration of each exceedance or excursion;
3) Cause of each exceedance or excursion;
4) Corrective actions taken on each exceedance or excursion;
5) Number of monitoring equipment downtime incidents;
6) Duration of each monitoring equipment downtime incident;
7) Cause of each monitoring equipment downtime incident;
8) Description of actions taken to implement a quality improvement plan for operating and monitoring, and upon completion of the quality improvement plan, documentation that the plan was completed and reduced the likelihood of similar excursions or exceedances and downtimes.

c) If an exemption is claimed pursuant to 401 KAR 59:016 and 40 CFR 60, Subpart Da, the permittee shall report:

1) The emergency conditions, type of start-up (cold, warm, or hot), and shut down;
2) The reason why the start-up was determined to be cold, warm, or hot (or the conditions that dictated a cold, warm, or hot start-up), as well as the shut down;
3) The emergency conditions, elapsed time of (or duration of) the start-up, and shut down;
4) The manufacturer's recommended duration for emergency conditions, that type of start-up or alternatively, typical, historical durations for that type of start-up, and shut down based upon good engineering practices; and

7. **Specific Control Equipment Operating Conditions:**

a) The control equipment enclosures, wet suppression, and baghouses used to control particulate emissions shall be operated to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and / or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 06 Two fly ash silos (Truck loadout)

Description:

The maximum loading rate: 300 tons/hr.
Construction commenced: 1993

Applicable Regulations:

401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

Applicable Requirements:

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

1. Application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts; and,

2. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

1. **Operating Limitations:** None

2. **Emission Limitations:** None

3. **Testing Requirements:** None

4. **Specific Monitoring Requirements:**

   The permittee shall monitor the amount of ash processed.

5. **Specific Record Keeping Requirements:**

   Records of the ash processed shall be maintained.

6. **Specific Reporting Requirements:**

   See Section F.

7. Specific Control Equipment Operating Conditions:

a) The enclosures and water spray system shall be operated to maintain compliance with applicable requirements, in accordance with manufacturer's specifications and / or standard engineering practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 07 - Coal Handling Operations

Description:

Rotary railcar unloader, barge unloader, sampling tower, radial stacker off-loading onto coal pile, haul roads, and yard area.
Operating rate: 4,600 tons/hr
Construction commenced: Prior to 1970

Applicable Regulations:
401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

Applicable Requirements:

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not be limited to the following:

1. Application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dusts;

2. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of
dusty materials, or the use of water sprays or other measures to suppress the dust emissions during handling;

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

1. Operating Limitations:
None

2. Emission Limitations:
None

3. Testing Requirements:
None

4. Specific Monitoring Requirements:
The permittee shall monitor the amount of coal received and processed.

5. Specific Record Keeping Requirements:
Records of the amount of coal received and processed shall be maintained.

6. Specific Reporting Requirements:
See Section F.

7. **Specific Control Equipment Operating Conditions:**

a) The control equipment (including but not limited to hoods, enclosures, use of dust suppressant/foam, telescopic chute, and water spray system) shall be operated to maintain compliance with applicable requirements in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

d) See Section F.

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

Emissions Unit 09 Coal Storage Pile

Description:

For unit 03 and Unit 04 Coal Storage Pile
Control Equipment: Wet Suppression, Telescopic Chute, or Dust Suppressant
Operating Rate: 750 tons/hour
Construction Commenced Date: February 8, 2002

Applicable Regulations:
401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not limited to the following:

1) application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dust; and

2) installation and use of compaction or other measures to suppress the dust emissions during handling; and

3) proper operation and maintenance of telescopic chutes to minimize emissions.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

c) Pursuant to 401 KAR 51:017, the permittee shall install control methods selected as BACT. See above.

2. Emission Limitations:

None.

3. Testing Requirements:

None

4. Specific Monitoring Requirements:

The permittee shall monitor application of wet suppression or dust suppressant as required by BACT.

5. Specific Record Keeping Requirements:

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

The permittee shall maintain records of the amount of coal received and processed.

6. Specific Reporting Requirements:

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) The control equipment (including, but not limited to, use of dust suppressant/foam, telescopic chute, and wet suppression) shall be operated to maintain compliance with applicable requirements of 401 KAR 51:017, and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

Emissions Unit 10 Coal Silos (4)

Description:

Machine Point 01 Coal Silos
Control Equipment: Baghouse
Operating Rate: 750 tons/hour
Construction Commenced Date: February 8, 2002

Applicable Regulations:

401 KAR 60:005(ff), which incorporates by reference 40 CFR 60 Subpart Y, Standards of Performance for Coal Preparation Plants.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

Pursuant to 401 KAR 51:017, the permittee shall install control methods selected as BACT.

2. **Emission Limitations:**

a) Pursuant to 40 CFR 60.252, the owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit twenty (20) percent opacity or greater.

b) Pursuant to 401 KAR 51:017, the baghouse utilized shall exhibit a design control efficiency of at least 99 %.

3. **Testing Requirements:**

Pursuant to 40 CFR 60.254, the permittee shall determine the opacity of emissions from each stack by EPA Reference Method 9 annually, or more frequently if requested by the Division for Air Quality.

4. **Specific Monitoring Requirements:**

The permittee must conduct weekly stack observations and maintain a log of the observations. If visible emissions are seen, the permittee must conduct a Method 9 observation to determine the opacity of the emissions. If the 20% opacity standard is exceeded, averaged on three 6-minute readings, the permittee shall initiate an inspection of the control equipment for any necessary repairs.

5. Specific Record Keeping Requirements:

a) The permittee shall monitor the amount of coal received and processed.

b) The permittee shall maintain the results of all compliance tests.

c) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

6. Specific Reporting Requirements:

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) The baghouse shall be maintained and operated to ensure the emission unit is in compliance with the applicable requirements of 40 CFR 60, Subpart Y and in accordance with manufacturer's specifications and/ or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 11 Bed Ash Handling System

Description:

Machine Point 01 – Bed Ash Silo
Control Equipment: Baghouse
Operating Rate: 44 tons/hour
Construction Commenced Date: February 8, 2002

Applicable Regulations:

401 KAR 59:010, New Process Operations
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

Pursuant to 401 KAR 51:017, the permittee shall install control equipment selected as BACT.

2. **Emission Limitations:**

a) Pursuant to 401 KAR 51:017 and 401 KAR 59:010, the permittee shall not cause to be discharged into the atmosphere from the above mentioned emissions units gases which exhibit twenty (20) percent opacity or greater.

b) Pursuant to 401 KAR 51:017, the baghouse utilized shall exhibit a design control efficiency of at least 99 %.

c) Pursuant to 401 KAR 59:010, particulate matter emissions shall not exceed 37.5 lbs/hr based on a three-hour average.

3. **Testing Requirements:**

a) Pursuant to 401 KAR 59:010, the permittee shall determine the opacity of emissions from each stack by EPA Reference Method 9 annually, or more frequently if requested by the Division for Air Quality.

b) EPA Reference Method 5 or Method 17 shall be performed as required by the Division for Air Quality to determine particulate matter concentration

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

4. **Specific Monitoring Requirements:**

a) The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

b) The pressure drop across baghouses will be checked and recorded on a continuous basis and compared with the manufacturer's specified operating range to ensure compliance.

5. **Specific Record Keeping Requirements:**

a) The permittee shall maintain records of amount of ash processed.

b) The permittee shall maintain results of all compliance tests and calculations.

i) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

ii) Pressure drop across the baghouses will be monitored through the use of a strip recorder or other continuous recording device. The permittee shall maintain strip recorder (or other continuous recording device) charts. In case of out-of-range indications, the permittee must log the date and time of the exceedance, the reason for the exceedance (if known) and the measures taken to correct the exceedance.

6. **Specific Reporting Requirements:**

See Section F, Conditions 5, 6, 7 and 8.

7. **Specific Control Equipment Operating Conditions:**

a) The baghouse shall be maintained and operated to maintain compliance with permitted emission limitations contained in 401 KAR 59:010 and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 12 Fly Ash Handling System

Description:

Machine Point 01 Fly Ash Silo

Control Equipment: Baghouse
Operating Rate: 71 tons/hour – Machine Point 01
Construction Commenced Date: February 8, 2002

Applicable Regulations:

401 KAR 59:010, New Process Operations
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

   Pursuant to 401 KAR 51:017, the permittee shall install control equipment selected as BACT.

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 51:017 and 401 KAR 59:010, the permittee shall not cause to be discharged into the atmosphere from the above mentioned emissions units gases which exhibit twenty (20) percent opacity or greater.

   b) Pursuant to 401 KAR 51:017, the baghouse utilized shall exhibit a design control efficiency of at least 99 %.

   c) Pursuant to 401 KAR 59:010, particulate matter emissions shall not exceed 50 lbs/hr based on a three-hour average.

3. **Testing Requirements:**

   a) Pursuant to 401 KAR 59:010, the permittee shall determine the opacity of emissions from each stack by as required by subsection 4(a) below, or more frequently if requested by the Division for Air Quality.

   b) EPA Reference Method 5 or Method 17 shall be performed as required by the Division for Air Quality to determine particulate matter concentration.

b) The pressure drop across baghouses will be checked and recorded on a continuous basis and compared with the manufacturer's specified operating range to ensure compliance.

5. **Reporting and Recordkeeping Requirements:**

a) Reporting and Recordkeeping shall be done in compliance with the requirements contained within 401 KAR 60:670.

b) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

c) Pressure drop across the baghouses will be monitored through the use of a strip recorder or other continuous recording device. The permittee shall maintain strip recorder (or other continuous recording device) charts. In case of out-of-range indications, the permittee must log the date and time of the exceedance, the reason for the exceedance (if known) and the measures taken to correct the exceedance.

d) Records of the limestone processed (tonnage) shall be maintained.

e) See Section F, Conditions 5, 6, 7 and 8.

6. **Specific Reporting Requirements:**

Pursuant to 401 KAR 60:670, specifically 40 CFR 60.676, the owner and/or operator shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672, including reports of opacity observations made using EPA Reference Method 9.

7. **Specific Control Equipment Operating Conditions:**

a) The facilities and baghouse shall be maintained and operated to ensure the emission unit is in compliance with applicable requirements of 401 KAR 60:670 and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

Emissions Unit 14 Limestone Storage

Description:

Machine Point 01 – Limestone Silo
Control Equipment: Baghouse
Operating Rate: 30 tons/hour
Construction Commenced Date: February 8, 2002

Applicable Regulations:

401 KAR 60:670, incorporating by reference 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants, as modified by Section 3 of 401 KAR 60:670
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

Pursuant to 401 KAR 51:017, the permittee shall install control equipment selected as BACT.

2. **Emission Limitations:**

a) Pursuant to 401 KAR 51:017, emissions of particulate shall be controlled by a baghouse with a design control efficiency of at least 99 %.

b) Pursuant to 401 KAR 60:670, emissions of particulate shall not exceed 0.05 gr/dscm and shall not exhibit greater than 7% opacity.

3. **Testing Requirements:**

a) Pursuant to 401 KAR 60:670, specifically 40 CFR 60.675(b)(2), the owner and/or operator shall use EPA Reference Method 9 and the procedures in 40 CFR 60.11 to determine opacity, annually.

b) EPA Reference Method 5 or Method 17 shall be performed as required by the Division to determine particulate matter concentration.

4. **Specific Monitoring Requirements:**

a) The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

See Section F, Conditions 5, 6, 7 and 8.

7. **Specific Control Equipment Operating Conditions:**

a) The control equipment (including, but not limited to, use of dust suppressant/foam, and wet suppression) shall be operated to maintain compliance with applicable requirements of 401 KAR 63:010, and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emission Unit 16 Cooling Tower

Description:

Control Equipment: 0.005% Drift Eliminators
Operating Rate: 2600 GPM
Construction Commenced Date: February 8, 2002

Applicable Regulations:

40 CFR 63, Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers
401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

   b) Pursuant to 40 CFR 63, Subpart Q, the permittee shall not use any chromium-based water treatment chemicals in the cooling tower

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 51:017, the cooling towers shall utilize 0.005% Drift Eliminators.

   b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

3. **Testing Requirements:**
   None

4. **Specific Monitoring Requirements:**
   None

5. **Reporting and Recordkeeping Requirements:**

   The permittee shall maintain the records of manufacturer design of the Drift Eliminators.

6. **Specific Reporting Requirements:**

   See Section F, Conditions 5, 6, 7 and 8.

7. **Specific Control Equipment Operating Conditions:**

a) The Drift Eliminators shall be operated in accordance with manufacturer's specifications and/or standard operating practices.

b) See Section E for further requirements.

Emissions Unit 18 Coal Silos

Description:

Machine point 04 Coal Silos
Control Equipment: Baghouse with 99% emission control efficiency
Operating Rate: 750 tons/hour
Construction Commenced Date: 2006

Applicable Regulations:

401 KAR 60:005(ff), incorporates by reference 40 CFR 60 Subpart Y, Standards of Performance for Coal Preparation Plants.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

Pursuant to 401 KAR 51:017, the permittee shall install control methods selected as BACT.

2. Emission Limitations:

a) Pursuant to 40 CFR 60.252, the owner or operator shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, gases which exhibit twenty (20) percent opacity or greater.

b) Pursuant to 401 KAR 51:017, the baghouse utilized shall exhibit a design control efficiency of at least 99 %, with a BACT limit of 0.10 lb/hr (or 0.00013 lb/ton).

3. Testing Requirements:

Pursuant to 40 CFR60.254, the permittee shall determine the opacity of emissions from each stack by EPA Reference Method 9 annually, or more frequently if requested by the Division for Air Quality.

4. Specific Monitoring Requirements:

a) The permittee must conduct weekly stack observations and maintain a log of the observations. If visible emissions are seen, the permittee must conduct a Method 9 observation to determine the opacity of the emissions. If the 20% opacity standard is exceeded, averaged on three 6-minute readings, the permittee shall initiate an inspection of the control equipment for any necessary repairs.

b) The pressure drop across the baghouses will be monitored and recorded on a continuous basis and compared with the manufacture's specified operating range to ensure compliance.

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

5. Specific Record Keeping Requirements:

a) The permittee shall monitor and record the amount of coal received and processed.

b) The permittee shall maintain results of all compliance tests and calculations.

1) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

2) Pressure drop across the baghouses will be monitored through the use of a strip recorder or other continuous recording device. The permittee shall maintain strip recorder (or other continuous recording device) charts. In case of out-of-range indications, the permittee must log the date and time of the exceedance, the reason for the exceedance (if known) and the measures taken to correct the exceedance.

6. Specific Reporting Requirements:

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) The baghouse shall be maintained and operated to ensure the emission unit is in compliance with the applicable requirements of 40 CFR 60, Subpart Y and in accordance with manufacturer's specifications and/ or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 19 (04) Bed Ash Handling System

Description:

Machine Point 04 – Bed Ash Silo
Control Equipment: Baghouse 99% emission control efficiency
Operating Rate: 44 tons/hour
Construction Commenced Date: 2006

Applicable Regulations:

401 KAR 59:010, New Process Operations
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

2. **Operating Limitations:**

Pursuant to 401 KAR 51:017, the permittee shall install control equipment selected as BACT.

2. **Emission Limitations:**

a) Pursuant to 401 KAR 59:010, the permittee shall not cause to be discharged into the atmosphere from the above mentioned emissions units gases which exhibit twenty (20) percent opacity or greater.

b) Pursuant to 401 KAR 51:017, the baghouse utilized shall exhibit a design control efficiency of at least 99 %, with a BACT limit of 0.034 lb/ton.

3. **Testing Requirements:**

a) Pursuant to 401 KAR 59:010, the permittee shall determine the opacity of emissions from each stack by EPA Reference Method 9 weekly, or more frequently if requested by the Division for Air Quality.

b) EPA Reference Method 5 or Method 17 shall be performed as required by the Division for Air Quality to determine particulate matter concentration.

4. **Specific Monitoring Requirements:**

a) The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

b) The pressure drop across baghouses will be checked and recorded on a continuous basis and compared with the manufacturer's specified operating range to ensure compliance.

5. Specific Record Keeping Requirements:

a) The permittee shall maintain records of amount of ash processed.

b) The permittee shall maintain results of all compliance tests and calculations.

1) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

2) Pressure drop across the baghouses will be monitored through the use of a strip recorder or other continuous recording device. The permittee shall maintain strip recorder (or other continuous recording device) charts. In case of out-of-range indications, the permittee must log the date and time of the exceedance, the reason for the exceedance (if known) and the measures taken to correct the exceedance.

6. Specific Reporting Requirements:

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) The baghouse shall be maintained and operated to maintain compliance with permitted emission limitations contained in 401 KAR 59:010 and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 20 (04) Fly Ash Handling System

Description:

Machine Point 04 Fly Ash Silo

Control Equipment: Baghouse 99% emission control efficiency
Operating Rate: 71 tons/hour
Construction Commenced Date: 2006

Applicable Regulations:

401 KAR 59:010, New Process Operations
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

   Pursuant to 401 KAR 51:017, the Permittee shall install control equipment selected as BACT.

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 51:017 and 401 KAR 59:010, the permittee shall not cause to be discharged into the atmosphere from the above mentioned emissions units gases which exhibit twenty (20) percent opacity or greater.

   b) Pursuant to 401 KAR 51:017, the baghouse utilized shall exhibit a design control efficiency of at least 99 %, with a BACT limit of 0.7 lb/ton (or 0.5 lb/hr).

   c) Pursuant to 401 KAR 59:010, particulate matter emissions shall not exceed 35 lbs/hr based on a three-hour average.

3. **Testing Requirements:**

   a) Pursuant to 401 KAR 59:010, the permittee shall determine the opacity of emissions from each stack by EPA Reference Method 9 weekly, or more frequently if requested by the Division for Air Quality.

   b) EPA Reference Method 5 or Method 17 shall be performed as required by the Division for Air Quality to determine particulate matter concentration.

4. **Specific Monitoring Requirements:**

   a) The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

b) The pressure drop across baghouses will be checked and recorded on a continuous basis and compared with the manufacturer's specified operating range to ensure compliance.

5. **Specific Record Keeping Requirements:**

a) The permittee shall maintain records of amount of ash processed.

b) The permittee shall maintain results of all compliance tests and calculations.

1) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

2) Pressure drop across the baghouses will be monitored through the use of a strip recorder or other continuous recording device. The permittee shall maintain strip recorder (or other continuous recording device) charts. In case of out-of-range indications, the permittee must log the date and time of the exceedance, the reason for the exceedance (if known) and the measures taken to correct the exceedance.

6. **Specific Reporting Requirements:**

See Section F, Conditions 5, 6, 7 and 8.

7. **Specific Control Equipment Operating Conditions:**

a) The baghouse shall be maintained and operated to maintain compliance with permitted emission limitations contained in 401 KAR 59:010 and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 21 Limestone Silo

Description:

Machine Point 04 – Limestone Silo
Control Equipment: Baghouse 99% emission control efficiency
Operating Rate: 30 tons/hour
Construction Commenced Date: 2002

Applicable Regulations:

401 KAR 60:670, incorporating by reference 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants, as modified by Section 3 of 401 KAR 60:670.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. Operating Limitations:

Pursuant to 401 KAR 51:017, the Permittee shall install control equipment selected as BACT.

2. Emission Limitations:

a) Pursuant to 401 KAR 51:017, emissions of particulate shall be controlled by a baghouse with a design control efficiency of at least 99 %.

b) Pursuant to 401 KAR 60:670, emissions of particulate shall not exceed 0.02 gr/dscm (or 0.86 lb/hr) and shall not exhibit greater than 7% opacity.

3. Testing Requirements:

a) Pursuant to 401 KAR 60:670, specifically 40 CFR 60.675(b)(2), the owner and/or operator shall use EPA Reference Method 9 in 40 CFR 60.11 to determine opacity, annually.

b) EPA Reference Method 5 or Method 17 shall be performed as required by the Division for Air Quality to determine particulate matter concentration.

4. Specific Monitoring Requirements:

a) The permittee shall perform a qualitative visual observation of the opacity of emissions from each stack on a weekly basis and maintain a log of the observations. If visible emissions from any stack are seen, then the permittee shall determine the opacity of emissions by Reference Method 9 and perform an inspection of the control equipment for any necessary repairs.

b) The pressure drop across baghouses will be checked and recorded on a continuous basis and compared with the manufacturer's specified operating range to ensure compliance

5. **Reporting and Recordkeeping Requirements:**

a) Reporting and Recordkeeping shall be done in compliance with the requirements contained within 401 KAR 60:670.

b) The permittee shall record each week the date, time and opacity of the visible emissions monitoring. In case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.

c) Pressure drop across the baghouses will be monitored through the use of a strip recorder or other continuous recording device. The permittee shall maintain strip recorder (or other continuous recording device) charts. In case of out-of-range indications, the permittee must log the date and time of the exceedance, the reason for the exceedance (if known) and the measures taken to correct the exceedance.

d) Records of the limestone processed (tonnage) shall be maintained.

e) See Section F, Conditions 5, 6, 7 and 8.

6. **Specific Reporting Requirements:**

Pursuant to 401 KAR 60:670, specifically 40 CFR 60.676, the owner and/or operator shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672, including reports of opacity observations made using EPA Reference Method 9.

7. **Specific Control Equipment Operating Conditions:**

a) The facilities and baghouse shall be maintained and operated to ensure the emission unit is in compliance with applicable requirements of 401 KAR 60:670 and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit 22 **Limestone Unloading**

Description:

Machine Point 04 – Limestone Truck Dump
Control Equipment: Wet Suppression or Dust Suppressant 99% emission control efficiency
Operating Rate: 30 tons/hour
Construction Commenced Date: 2006

Applicable Regulations:

401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not limited to the following:

1) application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dust; and
2) installation and use of compaction or other measures to suppress the dust emissions during handling.

b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

c) Pursuant to 401 KAR 51:017, the permittee shall install control methods selected as BACT. See above.

2. **Emission Limitations:**

See 1 above.

3. **Testing Requirements:**
None

4. **Specific Monitoring Requirements:**

The permittee shall monitor application of wet suppression or dust suppressant as required by BACT.

5. **Reporting and Recordkeeping Requirements:**

Records of limestone processed (tonnage) shall be maintained.

6. Specific Reporting Requirements:

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) The control equipment (including, but not limited to, use of dust suppressant/foam, and wet suppression) shall be operated to maintain compliance with applicable requirements of 401 KAR 63:010, and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emission Unit 23 Cooling Tower

Description:

Generator Unit 04 Cooling Tower
Control Equipment: 0.0005% Drift Eliminators
Operating Rate: 2800 GPM
Construction Date projected: 2006

Applicable Regulations:

40 CFR 63, Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers;
401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality;
401 KAR 51:017, Prevention of significant deterioration of air quality applicable to major construction or modification commenced after September 22, 1982.

1. **Operating Limitations:**

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

   b) Pursuant to 40 CFR 63, Subpart Q, the permittee shall not use any chromium-based water treatment chemicals in the cooling tower.

2. **Emission Limitations:**

   a) Pursuant to 401 KAR 51:017, the cooling tower shall utilize 0.0005% Drift Eliminators.

   b) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne.

3. **Testing Requirements:**
   The permittee shall conduct an initial performance test based on Cooling Technology Institute (CTI) Acceptance Test Code (ATC) # 140 to verify drift percent achieved by the drift eliminator.

4. **Specific Monitoring Requirements:**

   The permittee shall monitor total dissolved solids content of the circulating water on a monthly basis.

5. Specific Record Keeping Requirements:

a) The owner or operator shall maintain records of the manufacturer's design of the Drift Eliminators.

b) The owner or operator shall maintain records of maximum pumping capacity and monthly records of the total dissolved solids content

6. Specific Reporting Requirements:

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) Pursuant to 401 KAR 50:055, Section 5, the drift eliminators shall be maintained and operated to ensure the emission units are in compliance with applicable requirements of 401 KAR 63:010 and in accordance with manufacturer's specifications and/or standard operating practices.

c) See Section E for further requirements.

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

Emissions Unit [New A & B] **Limestone Unloading/ Storage**

Description:

Limestone truck loadout (A) and limestone storage pile (B) for facility
Machine Point 01 – Limestone truck dump
Machine Point 02 – Limestone offloading to hopper
Control Equipment: Wet Suppression or Dust Suppressant 90% emission control efficiency
Operating Rate: 73 tons/hour (annual average)
Construction Commenced Date: 2006

Applicable Regulations:

401 KAR 63:010, Fugitive emissions is applicable to each affected facility which emits or may emit fugitive emissions and is not elsewhere subject to an opacity standard within the administrative regulations of the Division for Air Quality.

1. **Operating Limitations:**

   a) Pursuant to 401 KAR 63:010, Section 3, reasonable precautions shall be taken to prevent particulate matter from becoming airborne. Such reasonable precautions shall include, when applicable, but not limited to the following:

   1) application and maintenance of asphalt, water, or suitable chemicals on roads, material stockpiles, and other surfaces which can create airborne dust; and
   2) installation and use of compaction or other measures to suppress the dust emissions during handling.

   b) Pursuant to 401 KAR 63:010, Section 3, discharge of visible fugitive dust emissions beyond the property line is prohibited.

2. **Emission Limitations:**

   See 1 above.

3. **Testing Requirements:**

   None

4. **Specific Monitoring Requirements:**

   None

5. **Reporting and Recordkeeping Requirements:**

   Records of limestone processed (tonnage) shall be maintained.

6. **Specific Reporting Requirements:**

See Section F, Conditions 5, 6, 7 and 8.

7. Specific Control Equipment Operating Conditions:

a) The control equipment (including, but not limited to, use of dust suppressant/foam, and wet suppression) shall be operated to maintain compliance with applicable requirements of 401 KAR 63:010, and in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the control equipment shall be maintained.

c) See Section E for further requirements.

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

Emissions Unit [New C-M)] **Limestone Preparations**

Description:

Machine Point C – 200 tons/hr Receiving hopper to conveyor
Machine Point D & E – 200 tons/hr Conveyor to day bins
Machine Point F & G – 200 tons/hr Day Bines to conveyors
Machine Point H & I – 100 tons/hr each two Weigh hoppers
Machine Point J & K – 100 tons/hr each two Conveyors to crushers
Machine Point L & M – 100 tons/hr each two Ball Mills Crushers
Control Equipment: Enclosures on all conveyors, and Baghouse on each crusher
Construction Commenced Date: 2006

Applicable Regulations:

401 KAR 60:670, incorporating by reference 40 CFR 60 Subpart OOO, Standards of Performance for Nonmetallic Plants applies to each of the emissions units listed above, commenced after August 31, 1983.

1. **Operating Limitations:**

   None

2. **Emission Limitations:**

   Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e), no owner or operator shall cause to be discharged into the atmosphere from any building enclosing any transfer point on a conveyor belt or any other emissions unit any visible fugitive emissions.

3. **Testing Requirements:**

   In determining compliance with 401 KAR 60.670, incorporating by reference 40 CFR 60.672(e) for fugitive emissions from buildings, the owner(s) or operator(s) shall determine fugitive emissions while all emissions units are operating in accordance with EPA Reference Method 22, annually.

4. **Specific Monitoring Requirements:**

   a) The permittee shall inspect the emissions control equipment weekly and make repairs to assure compliance.
   b) The permittee shall check and record the pressure drop across the baghouses on a continuous basis, and comply with manufacture's operating specification.

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

5. Reporting and Recordkeeping Requirements:

a) Records of the lime and/or limestone processed shall be maintained for emissions inventory purposes.
b) The permittee shall record monitoring of the opacity on a weekly basis. And in case of an exceedance, the permittee must record the reason (if known) and the measures taken to minimize or eliminate the exceedance.
c) Pressure drop across the baghouse shall be continuously recorded, and in case of exceedance, the reason for the exceedance (if known) and he measures taken to correct the exceedance shall be maintained.
d) See section F, conditions 5, 6, 7, and 8.

6. Specific Reporting Requirements:

a) Pursuant to 401 KAR 60.670, incorporating by reference 40 CFR 60.676, the owner(s) or operator(s) of any emissions unit shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards of 40 CFR 60.672 and Regulation 401 KAR 59:310, including reports of observations using Method 22 to demonstrate compliance.
b) See Section F.

7. Specific Control Equipment Operating Condition:

a) The enclosure shall be used to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices.

b) Records regarding the maintenance of the enclosure shall be maintained.

c) See Section E for further requirements.

SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. While these activities are designated as insignificant the permittee must comply with the applicable regulation and some minimal level of periodic monitoring may be necessary. Process and emission control equipment at each insignificant activity subject to a general applicable regulation shall be inspected monthly and qualitative visible emission evaluation made. The results of the inspections and observations shall be recorded in a log, noting color, duration, density (heavy or light), cause and any conservative actions taken for any abnormal visible emissions.

	Description	Generally Applicable Regulation
1.	Storage vessels containing petroleum or organic liquids with a capacity of less than 10,567 gallons, providing (a) the vapor pressure of the stored liquid is less than 1.5 psia at storage temperature, or (b) vessels greater than 580 gallons with stored liquids having greater than 1.5 psia vapor pressure are equipped with a permanent submerged fill pipe.	NA
2.	Storage vessels containing inorganic aqueous liquids, except inorganic acids with boiling points below the maximum storage temperature at atmospheric pressure.	NA
3.	#2 oil-fired space heaters or ovens rated at less than two million Btu per hour actual heat input, provided the maximum sulfur content is less than 0.5% by weight.	NA
4.	Machining of metals, providing total solvent usage at the source for this activity does not exceed 60 gallons per month.	NA
5.	Internal combustion engines using only gasoline, diesel fuel, natural gas, or LP gas rated at 50 hp or less.	NA
6.	Volatile organic compound and hazardous air pollutant storage containers, as follows: (a) Tanks, less than 1,000 gallons, and throughput less than 12,000 gallons per year; (b) Lubricating oils, hydraulic oils, machining oils, and machining fluids.	NA
7.	Machining where an aqueous cutting coolant continuously floods machining interface.	NA
8.	Degreasing operations, using less than 145 gallons per year.	NA
9.	Maintenance equipment, not emitting HAPs: brazing, cutting torches, soldering, welding.	NA
10.	Underground conveyors.	NA

SECTION C - INSIGNIFICANT ACTIVITIES

	Description	Generally Applicable Regulation
11.	Coal bunker and coal scale exhausts.	401 KAR 63:010
12.	Blowdown (sight glass, boiler, compressor, pump, cooling tower).	NA
13.	Stationary fire pumps.	NA
14.	Grinding and machining operations vented through fabric filters, scrubbers, mist eliminators, or electrostatic precipitators (e.g., deburring, buffing, polishing, abrasive blasting, pneumatic conveying, woodworking).	401 KAR 63:010
15.	Vents from ash transport systems not operated at positive pressure.	401 KAR 63:010
16.	Wastewater treatment (for stream less than 1% oil and grease).	NA
17.	Heat exchanger cleaning and repair.	NA
18.	Repair and maintenance of ESP, fabric filters, etc.	NA
19.	Any operation using aqueous solution (less than 1% VOC).	NA
20.	Laboratory fume hoods and vents used exclusively for chemical or physical analysis, or for "bench scale production" R&D facilities.	NA
21.	Machinery lubricant and waxes, including oils, greases or other lubricants applied as temporary protective coatings.	NA
22.	Purging of gas lines and vessels related to routine maintenance.	NA
23.	Flue gas conditioning systems.	NA
24.	Equipment used to collect spills.	NA
25.	Ash pond and ash pond maintenance.	NA
26.	Emergency generators: gasoline-powered (<110 hp), diesel-powered (<1600 hp).	NA
27.	Lime handling system; including truck unloading (for scrubber lime and stabilization lime), and lime feed systems. (changed to EU-05 non insignificant)	401 KAR 63:010

SECTION C - INSIGNIFICANT ACTIVITIES (CONTINUED)

	Description	Generally Applicable Regulation
28.	Fly ash storage silos (both loading and unloading).	401 KAR 63:010
29.	Off-specification used oil fuel burned for energy recovery	NA
30.	Bottom ash screening and sizing system.	401 KAR 63:010
31.	Railcar/truck flyash loadout.	401 KAR 63:010

SECTION E - SOURCE CONTROL EQUIPMENT REQUIREMENTS

Pursuant to 401 KAR 50:055, Section 2(5), at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

1. Pursuant to Section 1b (IV)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26, when continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:
   a. Date, place as defined in this permit, and time of sampling or measurements;
   b. Analyses performance dates;
   c. Company or entity that performed analyses;
   d. Analytical techniques or methods used;
   e. Analyses results; and
   f. Operating conditions during time of sampling or measurement.

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division for Air Quality, shall be retained by the permittee for a period of five years and shall be made available for inspection upon request by any duly authorized representative of the Division for Air Quality [Sections 1b(IV) 2 and 1a(8) of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. In accordance with the requirements of 401 KAR 52:020 Section 3(1)h the permittee shall allow authorized representatives of the Cabinet to perform the following during reasonable times:
   a. Enter upon the premises to inspect any facility, equipment (including air pollution control equipment), practice, or operation;
   b. To access and copy any records required by the permit:
   c. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements.

   Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit, other than continuous emission or opacity monitors, shall be submitted to the Regional Office listed on the front of this permit at least every six (6) months during the life of this permit, unless otherwise stated in this permit. For emission units that were still under construction or which had not commenced operation at the end of the 6-month period covered by the report and are subject to monitoring requirements in this permit, the report shall indicate that no monitoring was performed during the previous six months because the emission unit was not in operation [Section 1b (V)1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

6. The semi-annual reports are due by January 30th and July 30th of each year. If continuous emission and opacity monitors are required by regulation or this permit, data shall be reported to the Technical Services Branch in accordance with the requirements of 401 KAR 59:005, General Provisions, Section 3(3). All reports shall be certified by a responsible official pursuant to 401 KAR 52:020 Section 23. All deviations from permit requirements shall be clearly identified in the reports.

7. In accordance with the provisions of 401 KAR 50:055, Section 1 the owner or operator shall notify the Regional Office listed on the front of this permit concerning startups, shutdowns, or malfunctions as follows:
   a. When emissions during any planned shutdowns and ensuing startups will exceed the standards, notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shut down, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.
   b. When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards, notification shall be made as promptly as possible by telephone (or other electronic media) and shall be submitted in writing upon request.

8. The owner or operator shall report emission related exceedances from permit requirements including those attributed to upset conditions (other than emission exceedances covered by Section F.7. above) to the Regional Office listed on the front of this permit within 30 days. Other deviations from permit requirements shall be included in the semiannual report required by Section F.6 [Section 1b (V) 3, 4. of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

9. Pursuant to 401 KAR 52:020, Permits, Section 21, the permittee shall annually certify compliance with the terms and conditions contained in this permit, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an alternative approved by the regional office) to the Regional Office listed on the front of this permit and the U.S. EPA in accordance with the following requirements:
   a. Identification of the term or condition;
   b. Compliance status of each term or condition of the permit;
   c. Whether compliance was continuous or intermittent;
   d. The method used for determining the compliance status for the source, currently and over the reporting period.
   e. For an emissions unit that was still under construction or which has not commenced operation at the end of the 12-month period covered by the annual compliance certification, the permittee shall indicate that the unit is under construction and that compliance with any applicable requirements will be demonstrated within the timeframes specified in the permit

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

f. The certification shall be postmarked by January 30th of each year. Annual compliance certifications should be mailed to the following addresses:

Division for Air Quality
Ashland Regional Office
1550 Wolohan Drive, Suite 1
Ashland, KY 41102-8942

U.S. EPA Region 4
Air Enforcement Branch
Atlanta Federal Center
61 Forsyth Street
Atlanta, GA 30303-8960

Division for Air Quality
Central Files
803 Schenkel Lane
Frankfort, KY 40601

10. In accordance with 401 KAR 52:020, Section 22, the permittee shall provide the Division with all information necessary to determine its subject emissions within thirty (30) days of the date the KYEIS emission survey is mailed to the permittee.

11. Results of performance test(s) required by the permit shall be submitted to the Division by the source or its representative within forty-five days or sooner if required by an applicable standard, after the completion of the fieldwork.

12. Within 18 months of startup of the Unit 08 CFB, the permittee shall install and commence operation of an ambient monitoring station for measurement of ambient ozone. The ozone monitoring equipment shall be operated and maintained in accordance with 40 CFR 58, Appendix B. If no ozone exceedances are observed for a period of three (3) consecutive years after commencement of operation of Emission Unit 17, the permittee may cease the monitoring program.

SECTION G - GENERAL CONDITIONS (CONTINUED)

16. Pursuant to 401 KAR 52:020, Section 11, a permit shield shall not protect the owner or operator from enforcement actions for violating an applicable requirement prior to or at the time of issuance. Compliance with the conditions of a permit shall be considered compliance with:

    a. Applicable requirements that are included and specifically identified in the permit and

    b. Non-applicable requirements expressly identified in this permit.

17. Pursuant to 401 KAR 50:045, Section 2, a source required to conduct a performance test shall submit a completed Compliance Test Protocol form, DEP form 6028, or a test protocol a source has developed for submission to other regulatory agencies, in a format approved by the cabinet, to the Division's Frankfort Central Office a minimum of sixty (60) days prior to the scheduled test date. Pursuant to 401 KAR 50:045, Section 7, the Division shall be notified of the actual test date at least Thirty (30) days prior to the test.

18. The permittee shall submit a startup and shut down plan to implement the requirements of this permit and 401 KAR 50:055. The plan shall be submitted at least ninety (90) days prior to the startup of the Unit #4 for the Division's approval. The startup/shutdown plan will be accessible for public review at the Division's central office and the regional office.

(b) Permit Expiration and Reapplication Requirements

1. This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the Division at least six months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division [401 KAR 52:020, Section 12].

2. The authority to operate granted shall cease to apply if the source fails to submit additional information requested by the Division after the completeness determination has been made on any application, by whatever deadline the Division sets [401 KAR 52:020 Section 8(2)].

(c) Permit Revisions

1. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the SIP or in applicable requirements and meet the relevant requirements of 401 KAR 52:020, Section 14(2).

SECTION G - GENERAL CONDITIONS (CONTINUED)

2. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division for Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority within ten (10) days following the transfer.

(d) Construction, Start-Up, and Initial Compliance Demonstration Requirements

Pursuant to a duly submitted applications the Kentucky Division for Air Quality hereby authorizes the construction of the equipment described herein, in accordance with the terms and conditions of this permit. Authority is granted by the following permit and permit revisions:

Emission Unit 17 and ancillary equipment	**(V-06-007)**
WFGD and WESP on both Units 1 & 2 and ancillary equipment	**(V-06-007 –Revision #1)**

1. Construction of any process and/or air pollution control equipment authorized by this permit shall be conducted and completed only in compliance with the conditions of this permit.

2. Within thirty (30) days following commencement of construction and within fifteen (15) days following start-up and attainment of the maximum production rate specified in the permit application, or within fifteen (15) days following the issuance date of this permit, whichever is later, the permittee shall furnish to the Regional Office listed on the front of this permit in writing, with a copy to the Division's Frankfort Central Office, notification of the following:
   a. The date when construction commenced.
   b. The date of start-up of the affected facilities listed in this permit.
   c. The date when the maximum production rate specified in the permit application was achieved.

3. Pursuant to 401 KAR 52:020, Section 3(2), unless construction is commenced within eighteen (18) months after the permit is issued, or begins but is discontinued for a period of eighteen (18) months or is not completed within a reasonable timeframe then the construction and operating authority granted by this permit for those affected facilities for which construction was not completed shall immediately become invalid. Upon written request, the Cabinet may extend these time periods if the source shows good cause.

4. For those affected facilities for which construction is authorized by this permit, a source shall be allowed to construct with the proposed permit. This permit does not grant operational or final permit approval until compliance with the applicable standards specified herein has been demonstrated pursuant to 401 KAR 50:055. If compliance is not demonstrated within the prescribed timeframe provided in 401 KAR 50:055, the source shall operate thereafter only for the purpose of demonstrating compliance, unless otherwise authorized by Section I of this permit or order of the Cabinet.

SECTION G - GENERAL CONDITIONS (CONTINUED)

d. Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.166.

e. Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

2. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, *Servicing of Motor Vehicle Air Conditioners*.

SECTION H – ALTERNATE OPERATING SCENARIOS

N/A

SECTION I – COMPLIANCE SCHEDULE

N/A

SECTION J - PHASE II ACID RAIN PERMIT

ACID RAIN PERMIT CONTENTS

1) Statement of Basis

2) SO_2 allowances allocated under this permit and NOx requirements for each affected unit.

3) Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.

4) The permit application submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the Phase II Application.

5) Summary of Actions

Statement of Basis:

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100 and Titles IV and V of the Clean Air Act, the Kentucky Environmental and Public Protection Cabinet, Division for Air Quality issues this permit pursuant to 401 KAR 52:020, 401 KAR 50:060, Acid Rain Permit, and 40 CFR Part 76 (Emission Units 01 and 02).

SECTION J - PHASE II ACID RAIN PERMIT
PERMIT (Conditions)

Plant Name: Hugh L. Spurlock Station
Affected Unit: 01

- **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2006	2007	2008	2009	2010
Tables 2, 3 or 4 of 40 CFR Part 73	9,821*	9,821*	9,821*	9,821*	9,841*

NO_x Requirements	
NO_x Limits	Pursuant to 40 CFR Part 76, the Kentucky Division for Air Quality approves a NO_x standard emissions limitation compliance plan for unit 1. The NO_x compliance plan is effective from January 1, 2000 through December 31, 2004. Under the NO_x compliance plan, annual average NO_x emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.5(a)(2), of 0.50 lb/MMBtu for dry bottom wall-fired boilers. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

* The number of allowances allocated to Phase II affected units by the U.S. EPA may change under 40 CFR part 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U. S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

SECTION J - PHASE II ACID RAIN PERMIT
PERMIT (Conditions)

Plant Name: Hugh L. Spurlock Station
Affected Unit: 02

- **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2006	2007	2008	2009	2010
Tables 2, 3 or 4 of 40 CFR Part 73	16,586*	16,586*	16,586*	16,586*	16,621*

NO_x Requirements	
NO_x Limits	Pursuant to 40 CFR Part 76, the Kentucky Division for Air Quality approves a NO_x standard emissions limitation compliance plan for unit 1. The NO_x compliance plan is effective from January 1, 2000 through December 31, 2004. Under the NO_x compliance plan, annual average NO_x emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.5(a)(1), of 0.45 lb/MMBtu for tangentially fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable limitation, under 40 CFR 76.7(a)(1), of 0.40 lb/MMBtu until calendar year 2008. In addition to the described NO_x compliance plan, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NO_x compliance plan and requirements covering excess emissions.

* The number of allowances allocated to Phase II affected units by the U.S. EPA may change under 40 CFR part 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U. S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

SECTION J - PHASE II ACID RAIN PERMIT
PERMIT (Conditions)

Plant Name: Hugh L. Spurlock Station
Affected Units: 03 (Emission Unit 08) **and 04** (Emission Unit 17)

- **SO_2 Allowance Allocations and NO_x Requirements for the affected unit:**

SO_2 Allowances	**Year**				
	2006	2007	2008	2009	2010
Tables 2, 3 or 4 of 40 CFR Part 73	0*	0*	0*	0*	0*

NO_x Requirements	
NO_x Limits	N/A**

* The number of allowances allocated to Phase II affected units by the U.S. EPA may change under 40 CFR Part 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

** This unit currently does not have applicable NO_x limits set by 40 CFR, part 76.

SECTION J - PHASE II ACID RAIN PERMIT

PERMIT (Conditions)

- **Comments, Notes, and Justifications:**

  Units 03 and 04 will be constructed after the SO_2 allocation date; therefore these units will have no SO_2 allowances allocated by U.S. EPA and must obtain allowances.

  Units 03 and 04 do not have applicable NO_x limits set by 40 CFR Part 76.

- **Permit Application:**
  The Phase II Permit Application is part of this permit and the source must comply with the standard requirements and special provisions set forth in the Phase II Application.

- **Summary of Actions:**

  Previous Actions:

  1. Draft Phase II Permit (# AR-96-11) including SO_2 compliance plan was issued for public comment on September 19, 1996.

  2. Final Phase II Permit (# AR-96-11) including SO_2 compliance plan was issued on December 11, 1996.

  3. Draft Phase II Permit (# A-98-010) was issued with the revised SO_2 allowance allocations and NO_x emissions standard for public comment on December 23, 1998.

  4. Final Phase II Permit (# A-98-010) was issued with the 1998 revised SO_2 allowance allocations and NO_x emission standard on June 1, 1999.

  5. Draft Phase II Permit has been proposed for public comment.

  Present Action:

  1. Final Phase II permit is being issued with the renewed Title V permit.

SECTION K – NOx BUDGET PERMIT

1) **Statement of Basis**

Statutory and Regulatory Authorities: In accordance with KRS 224.10-100, the Kentucky Environmental and Public Protection Cabinet issues this permit pursuant to 401 KAR 52:020 Title V permits, 401 KAR 51:160, NO_x requirements for large utility and industrial boilers, and 40 CFR 97, Subpart C.

2) **NO_x Budget Permit Application, Form DEP 7007EE**

The initial NO_x Budget Permit application for electrical generating units (1-3) was submitted to the Division and received on November 24, 2003. Application for Unit 4 was received with the PSD application initially submitted on September 13, 2004 Requirements contained in that application are hereby incorporated into and made part of this NO_x Budget Permit. Pursuant to 401 KAR 52:020, Section 3, the source shall operate in compliance with those requirements.

3) **Comments, notes, justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions.**

Affected units are one (1) 3500MMBtu/hr dry-bottom wall-fired boiler, one (1) 5600 MMBtu/hr tangentially fired boiler, one (1) 2500 MMBtu/hr pulverized coal-fired CFB boiler and one (1) 2800 MMBtu/hr pulverized coal-fired CFB boiler. Each unit has a capacity to generate 25 megawatts or more of electricity, which is offered for sale. The units use coal as a fuel source, and are authorized as base load electric generating units.

4) **Summary of Actions**

The NO_x Budget Permit is being issued as part of this renewed and revised Title V permit for this source. Public, affected state, and U.S. EPA review will follow procedures specified in 401 KAR 52:100.

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF EAST KENTUCKY POWER COOPERATIVE, INC. HUGH L. SPURLOCK GENERATING STATION MAYSVILLE, KENTUCKY PETITION IV-2006-4 PERMIT NO. V-06-007 ISSUED BY THE KENTUCKY ENVIRONMENTAL PROTECTION CABINET DEPARTMENT FOR ENVIRONMENTAL PROTECTION, DIVISION FOR AIR QUALITY	ORDER RESPONDING TO PETITIONER'S REQUEST THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF STATE PERMIT

ORDER GRANTING IN PART AND DENYING IN PART PETITION FOR OBJECTION TO PERMIT

On August 17, 2006, the United States Environmental Protection Agency (EPA) received a petition from the Sierra Club (Petitioner) pursuant to section 505(b)(2) of the Clean Air Act (CAA or the Act), 42 U.S.C. § 7661d(b)(2). Sierra Club's petition requests that the Administrator object to the permit issued by the Kentucky Division for Air Quality (KYDAQ or Kentucky) to East Kentucky Power Cooperative, Inc. (EKPC), for the operation of the Hugh L. Spurlock Generating Station (Spurlock Station) located in Maysville, Kentucky. The permit (No.V-06-007) is a state-issued operating permit for Units 1 through 4 at the Spurlock Station, with a combined Prevention of Significant Deterioration (PSD) construction air quality permit for Unit 4, and was issued by KDAQ pursuant to Kentucky Administrative Regulations (KAR) at 401 KAR 52:020 and 40 KAR. 51.017.

Sierra Club's petition raises several issues in requesting that EPA object to this permit. Petitioner alleges that: (1) the permit does not specify whether continuous opacity monitoring (COMS) data will be available to prove a violation of the opacity standard for Unit 1; (2) the permit must include a heat input limit under the heading *Operating Limits* for Unit 2; (3) the permit must contain a compliance schedule for bringing Unit 2 into compliance with PSD requirements; (4) the permit improperly omits an applicable requirement to construct and operate Unit 3 consistent with and according to the specifications provided in its permit application; (5) the permit contains erroneous best available control technology (BACT) limits at Unit 3 for several pollutants; (6) the permit contains

EXHIBIT B

unenforceable limits related to particulate matter and hazardous air pollutant emissions from Unit 3; and (7) the permit contains erroneous BACT limits for Unit 4.

EPA has reviewed these allegations pursuant to the standard set forth in section 505(b)(2) of the Act, which requires the Administrator to issue an objection if the Petitioner demonstrates to the Administrator that the permit is not in compliance with the applicable requirements of the Act. *See also* 40 C.F.R. § 70.8(d); *Sierra Club v. Johnson,* 436 F.3d 1269, 1280 (11th Cir. 2006); and *New York Public Interest Group v. Whitman*, 321 F.3d 316, 333 n.11 (2nd Cir. 2002).

Based on a review of the information before me, including the petition; the facility's permit application dated January 20, 2006; the final effective permit issued on July 31, 2006; the administrative record supporting the permit; KYDAQ's Response to Comments dated June 1, 2006; and relevant statutory and regulatory authorities, I partially deny and partially grant Petitioner's request for the reasons set forth in this Order.

I. STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(1) of the Act, 42 U.S.C. § 7661a(d)(1), calls upon each state to develop and submit to EPA an operating permit program intended to meet the requirements of CAA title V. The Commonwealth of Kentucky originally submitted its title V program governing the issuance of operating permits in 1993. EPA granted interim approval to the program on November 14, 1995. *See* 60 Fed. Reg. 57186. Full approval was granted by EPA on October 31, 2001. *See* 66 Fed. Reg. 54953. The program is now incorporated into Kentucky's Administrative Regulations at 401 KAR 52:020. All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the Act, including the applicable implementation plan. *See* CAA § 502(a) and 504(a), 42 U.S.C. § 7661a(a) and 7661c(a).

The title V operating permit program does not generally impose new substantive air quality control requirements (which are referred to as "applicable requirements") but does require permits to contain monitoring, recordkeeping, reporting, and other conditions to assure compliance by sources with all applicable requirements. 40 C.F.R. § 70.1(b); *see also* 57 Fed. Reg. 32250, 32251 (July 21, 1992). One purpose of the title V program is to "enable the source, States, EPA, and the public to better understand the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permit program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units in a single document and that compliance with these requirements is assured.

A. Title V Review

Under section 505(a) of the Act and the relevant implementing regulations, *see* 42 U.S.C. § 7661d(a); 40 C.F.R. § 70.8(a), states are required to submit each proposed title V permit to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if it is determined not to be in compliance with applicable requirements or the requirements of title V. 40 C.F.R. § 70.8(c). If EPA does not object to a permit on its own initiative, section 505(b)(2) of the CAA provides that any person may petition the Administrator, within 60 days of the expiration of EPA's 45-day review period, to object to the permit. 42 U.S.C. § 7661d(b)(2); *see also* 40 C.F.R. § 70.8(d). In response to such a petition, the Act requires the Administrator to issue a permit objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act, including the requirements of 40 C.F.R. part 70 and the applicable state implementation plan (SIP). 42 U.S.C. § 7661d(b)(2); *see also*, 40 C.F.R. § 70.8(c)(1); *New York Public Interest Research Group (NYPIRG) v. Whitman*, 321 F.3rd 316, 333 n.11 (2nd Cir. 2003).

Petitions must be based on objections to the permit raised with reasonable specificity during the public comment period, unless the petitioner demonstrates that it was impracticable to raise such objections within that period or the grounds for such objections arose after that period. CAA § 7661d(b)(2); 40 C.F.R. § 70.8(c)(1). If the permitting authority has not yet issued the permit, it may not do so unless it revises the permit and issues it in accordance with section 505(c) of the Act, 42 U.S.C. § 7661d(c). However, a petition for review does not stay the effectiveness of the permit or its requirements if, as is the case here, the permitting authority issued the permit after the expiration of EPA's 45-day review period and before receipt of the petition for review. If, in responding to a petition, EPA objects to a permit that has already been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures set forth in 40 C.F.R. §§ 70.7(g)(4) and (5)(i) - (ii), and 40 C.F.R. § 70.8(d).

B. Applicable PSD Requirement

For new major stationary sources,[1] applicable requirements include the requirement to obtain a preconstruction permit that complies with applicable new source review and PSD requirements. Part C of the CAA establishes the PSD program, the preconstruction review program that applies to areas of the country that have attained the National Ambient Air Quality Standards (NAAQS). CAA §§ 160–169, 42 U.S.C. §§ 7470-7479. In such areas, a major stationary source may not begin construction or undertake certain modifications without first obtaining a

[1] "Major stationary source" is defined, *inter alia*, as a fossil fuel-fired steam electric plant of more than 250 British thermal units (Btu) per hour heat input with the potential to emit 100 tons per year or more of certain criteria pollutants, such as nitrogen oxide (NO_x), sulfur dioxide (SO_2), or particulate matter (PM). 40 C.F.R. § 51.166(b)(1)(i)(a); and 401 KAR 51.001.

PSD permit. CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1). In broad overview, the PSD program includes two central requirements that must be satisfied before the permitting authority may issue a permit; the program (1) limits the impact of new or modified major stationary sources on ambient air quality and (2) requires the application of state-of-the-art pollution control technology, known as BACT. CAA §§ 165(a)(3) & (4), 42 U.S.C. §§ 7475(a)(3) and (4). The CAA further 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, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant." CAA § 169(3) (emphasis added); *see also* 401 KAR 51.001.

EPA has promulgated two largely identical sets of regulations to implement the PSD program. One set, at 40 CFR § 52.21, contains EPA's own federal PSD program, which was incorporated into the implementation plans of all states at the inception of the PSD program in the 1970s. EPA is the permitting authority in states operating under 40 CFR § 52.21 and permits issued under such programs are federal permits that may be appealed to EPA's Environmental Appeals Board, and ultimately, the federal courts of appeals. The other set of regulations contain requirements that state PSD programs must meet to be approved as part of a SIP. 40 CFR § 51.166. Over time, most states have received EPA approval for their PSD programs. In 1989, EPA approved Kentucky's PSD revision to its SIP as meeting these requirements in relevant part. 54 Fed. Reg. 36307 (September 1, 1989); *see also* 40 CFR § 52.931. For new major stationary sources in Kentucky and for major modifications of existing sources, the Commonwealth's regulations require sources to apply for a PSD permit at the same time that it applies for its title V operating permit. 401 KAR 52:020.

Where, as in this case, Petitioner's request that the Administrator object to the issuance of a title V permit is based in whole, or in part, on KYDAQ's alleged failure to comply with the requirements of the Commonwealth's approved PSD program in issuing a combined title V/PSD permit, the burden is on Petitioner to demonstrate that KYDAQ clearly erred by issuing the PSD permit with terms that are not in compliance with applicable PSD requirements.

As noted above, EPA has approved the PSD programs of most states, including the Commonwealth of Kentucky. As the permitting authority, such states have substantial discretion in issuing PSD permits. Given this, in reviewing a state's PSD permitting decision, EPA will not substitute its own judgment for that of the state. Rather, consistent with the decision in *Alaska Dep't of Envt'l Conservation v. EPA*, 540 U.S. 461 (2004), EPA's oversight role in the review of PSD permits in the context of a title V petition is limited to ensuring that the state has adequately explained the basis for its determination and that the PSD permit comports with the requirements of the state's approved PSD program.

In determining the appropriate standard to apply to the PSD determinations in this case, the standard of review applied by the Environmental Appeals Board (EAB) in reviewing the appeals of federal PSD permits issued pursuant to the federal regulations at 40 CFR § 52.21, provides a useful analogy. Unlike title V objections, the appeal of federal PSD permits is governed by the regulations at 40 CFR § 124.19, and authority to review such permits rests exclusively with the EAB.[2] The standard of review applied by the EAB in its review of federal PSD permits has been explained in numerous orders of the EAB. *See* e.g., *Prairie State Generation Company,* PSD Appeal No. 05-05, slip op. (EAB, Aug. 24, 2006); *Kawaihae Cogeneration,* 7 E.A.D. 107, 114 (EAB 1997). In short, in such appeals, the burden is on a petitioner to demonstrate that review is warranted. Ordinarily, a PSD permit will not be reviewed by the EAB unless the decision of the permitting authority was based on either a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that warrants review.

Thus, when a response to a petition to object to a title V permit requires the Administrator to determine whether an approved state's PSD permitting decision was adequately explained and meets the requirements of its SIP, EPA believes it is appropriate to apply a similar standard of review to that employed by the EAB in its review of federal PSD permits. When EPA promulgated the regulations governing the EAB's exercise of its review authority, the Agency noted that the power of review "should be only sparingly exercised." 45 Fed. Reg. 33290, 33412. Similar deference to the permitting authority is also justified in the case of a PSD permit issued by a state with an approved PSD program, as is the case here.

II. BACKGROUND

A. The Facility

The facility at issue - Spurlock Station - is an electric generating plant owned and operated by EKPC in Maysville, Mason County, Kentucky. The plant burns fossil fuels, primarily coal, to generate electricity. The plant includes two pulverized coal boilers and one circulating fluidized bed (CFB) boiler, with plans to construct an additional CFB boiler.

Emission Unit 1 is a 3500 mmBtu/hr dry-bottom wall fired boiler equipped with electrostatic precipitators (ESPs) and a low-NO_x burner, for which

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[2]Because of the exclusive authority of the EAB in this area, the Administrator has declined to review the merits of a federal PSD permit in the context of a petition to review a title V permit. *See e.g., In re Kawaihae Cogeneration Project,* Petition No. 0001-01-C (March 10, 1997).

construction began before 1971. The precipitators were installed as part of the original plant construction but were rebuilt in 1990-1992. In addition, a selective catalytic reduction device was installed in 2003.

Emission Unit 2 is a 4850 mmBtu/hr tangentially fired boiler equipped with ESPs, low NO_x burners, and a flue gas desulfurization (FGD) system and was subject to review under 40 C.F.R. part 52.21, in November 1979. The FGD system has not been in operation since 1985. A selective catalytic reduction device was installed in 2003, after the date of the original title V permit issuance.

Emission Unit 3 was constructed in 2002. It is a 2,500 mmBtu/hr CFB boiler equipped with a baghouse filter, flash dry absorber and a selective non-catalytic reduction (SCNR) unit. This unit burns coal and tire derived fuel (TDF) with the condition that TDF will not be burned in excess of 10 percent of coal fuel by weight ratio.

Emission Unit 4 will be constructed at EKPC's existing Spurlock Station pursuant to issuance of the title V and combined PSD permit. Unit 4 is a new 300 megawatt coal-fired electric utility boiler, utilizing CFB technology. The new CFB boiler will be equipped with selective non-catalytic reduction, pulse jet fabric filters, dry scrubbing, and limestone injection pollution control systems. Unit 4 is virtually identical to the existing Unit 3, which also has a CFB boiler.

B. The Permit

The Spurlock Station title V permit at issue is a renewal permit. EKPC submitted an application for its initial operating permit in January 1976 to construct Unit 2. The initial operating permit issued by Kentucky was effective on November 10, 1982. The 1983 permit was subsequently amended on October 7, 1983. In 1996, EKPC submitted title V permit applications for its Dale and Spurlock units. On December 10, 1999, Kentucky issued a final title V permit for Spurlock Unit 2. On April 24, 2001, EKPC submitted a construction permit application for Spurlock Unit 3. The application was considered to be complete on February 8, 2002. The permit for Unit 3 became effective on June 21, 2002.

On June 8, 2004, KYDAQ received an application for renewal of the title V permit. This title V permit is combined with the proposed construction of Unit 4. EKPC submitted an air permit application dated September 13, 2004, seeking a permit to construct a new 300 megawatt net nominal generating unit. Kentucky's permit program provides for PSD permitting to occur concurrently with the title V permitting process. From December 2004 through January 2006, EKPC provided KYDAQ with additional information to support the combined title V and PSD permitting process. The application was administratively completed on January 20, 2006. Thereafter, KYDAQ proposed a draft title V permit and provided a public comment period, during which KYDAQ received timely comments, including those submitted by the Petitioner. EPA did not object to the proposed permit within its

45-day review period, which ended July 27, 2006. KYDAQ issued the final permit on July 31, 2006, which included the renewals of the existing title V permit for Units 1 though 3 and the initial combined title V and PSD permit for Unit 4.

C. Litigation History

On January 24, 2003, EPA issued an Notice of Violation (NOV) to EKPC for PSD violations at the Spurlock Station concerning Unit 2. Subsequently on January 29, 2004, EPA filed an enforcement action in federal district court against EKPC alleging similar PSD violations at Unit 2. *U.S. v. East Kentucky Power Cooperative, Inc.*, Case No. 04-34-KSF (E.D. KY).[3] While the parties have entered into a proposed consent decree to resolve the enforcement proceeding, it has not yet been finalized by the court.

In addition, Petitioner brought a state administrative challenge of this title V permit pursuant to the Kentucky Revised Statute (KRS) 224.10-440. A formal administrative hearing on that challenge was held on December 4, 2006. At the conclusion of the oral arguments, the case was submitted to the Secretary of the Kentucky Environmental and Public Protection Cabinet (Secretary) for issuance of the final Order. The Hearing Officer's Report and Recommended Secretary's Order was filed on April 16, 2007. The Secretary has until September 12, 2007, to file a final Order in the administrative proceeding.[4]

Finally, on September 28, 2006, Petitioner filed a deadline suit to compel the Administrator to respond to the title V petition at issue in this Order. *Sierra Club v.*

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[3] The United States alleged, *inter alia*, that EKPC performed "major modifications" at the Spurlock and Dale Plants, within the meaning of the regulations implementing the PSD program, in connection with a series of capital projects and operational changes at the Spurlock Plant to supply steam to the Inland Container Corporation, and a series of capital projects at the Dale Plant involving the replacement of boiler and turbine components. At Spurlock Unit 2 and Dale Units 3 and 4, the United States alleged that these projects resulted in unpermitted "significant net emission increases" of NO_x, SO_2 and/or PM under the PSD program. The United States asked that the Court order EKPC, *inter alia*, to remedy the alleged violations by requiring installation of the best available control technology on Spurlock Unit 2 and Dale Units 3 and 4, in order to control and reduce emissions of NO_x, SO_2 and/or PM. The United States also alleged that the projects undertaken at Dale Units 3 and 4 violated the applicable New Source Performance Standards for these pollutants, and that EKPC failed to include PSD and NSPS requirements triggered by its projects in its operating permits required by title V of the CAA. On July 2, 2007, the United States and EKPC lodged a proposed Consent Decree in the U.S. District Court for the Eastern District of Kentucky. Judicial approval of the settlement is pending court review.

[4] The issues presented at the hearing include the following allegations:(a) that the Cabinet failed to make certain information available to the public during the public comment period; and (b) that the Cabinet erred in determining the BACT selection for NO_x for Unit 4.

Johnson, No 1:07CV00414 (RWR) (D.D.C). On July 18, 2007, notice of the proposed consent decree to address this deadline lawsuit was published. 72 Fed. Reg. 9413. Pursuant to the terms of the proposed consent decree, EPA has until August 31, 2007, to respond to the petition.

III. THRESHOLD REQUIREMENTS

A. Timeliness of Petition

Section 505(b)(2) of the Act provides that a person may petition the Administrator of EPA, within sixty days after the expiration of EPA's 45-day review period, to object to the issuance of a proposed permit. As noted above, EPA's 45-day review period for the Spurlock Station title V permit expired on July 27, 2006. Thus, the sixty-day petition period ended on September 27, 2006. EPA received the subject petition on August 17, 2006. Accordingly, EPA finds that Petitioner timely filed its petition.

B. Objections Raised with Reasonable Specificity During Public Comment Period

The Petitioner filed this petition pursuant to CAA § 505(b)(2), under which the Administrator will object to a permit if "the petitioner demonstrates to the Administrator that the permit is not in compliance with the requirements of this Act, including the requirements of the applicable implementation plan." EPA considers whether the Petitioner has provided sufficient information to make the requisite "demonstrat[ion]" under the facts, circumstances, and legal issues of the particular case, viewed in light of the provisions, structure of title V and the relationship of those provisions with the enforcement provisions of title I. *See In the Matter of Georgia Power Bowen Steam –Electric Generating Plant, et al Final Order*, dated January 8, 2007. Section 505(b)(2) of the Act also provides that a petition shall be based on objections raised with reasonable specificity during the public comment period provided by the permitting agency. EPA reviewed the comments submitted to Kentucky during the public comment period for the Spurlock Station title V permit and found that the comments provide a sufficient basis for the petition – the objections raised in the petition were timely raised, with reasonable specificity, in Petitioner's written comments. Therefore, Petitioner has satisfied this statutory requirement.

IV. ISSUES RAISED BY THE PETITIONER

A. Use of Credible Evidence

<u>Petitioner's Comment</u>: Petitioner points to the permit's specific monitoring requirements for Unit 1 and asserts that Section B.4.a. could be read to limit the credible evidence that may be used to establish an opacity violation. Petitioner states that when the continuous opacity monitoring system (COMS) indicates an

exceedance of the opacity standard, the permit requires the source to either conduct a Method 9 test or accept the COMS readout, but asserts that this provision is not a limit on the type of evidence that can be used to enforce the underlying opacity limit. Petitioner asks the Administrator to object to the permit because it may create confusion on this point.

EPA's Response: EPA interprets the title V permit to allow EPA, KYDAQ, citizens and EKPC to use any credible evidence to determine compliance with and/or enforce an applicable requirement of the permit. This interpretation is grounded in both the CAA's statutory and regulatory enforcement provisions, as well as the provisions of the title V permit itself.

The Act provides EPA, KYDAQ and citizens with authority to bring enforcement actions against a source for violation of any requirement or prohibition of an applicable implementation plan or permit, including a title V permit. 42 U.S.C. §§ 7413(a), 7604(a)(1), 7604(f)(4). Section 113(a) of the CAA provides that EPA may bring an enforcement action based on "any information." 42 U.S.C. § 7413(a). In response to a 1984 district court ruling that limited the evidence EPA could use to prove a violation of an emission standard or limitation, Congress amended Section 113(e) of the CAA in 1990, to clarify that "any credible evidence" could be used for compliance and enforcement purposes. 42 U.S.C. § 7413(e).

EPA promulgated the Credible Evidence Rule (CER) following the 1990 CAA Amendments, to further clarify that any credible evidence could be used for compliance with the new title V permit program, as well as other compliance and enforcement efforts. 62 Fed. Reg. 8314 (February 24, 1997). As stated in the preamble, the CER "merely removes what some have construed to be a regulatory bar to the admission of non-reference test data to prove a violation of an emission standard, no matter how credible and probative those data are that a violation has occurred." 62 Fed.Reg. at 8315. Specifically, the CER was "designed to clarify that non-reference test data can be used in enforcement actions, and to remove any potential ambiguity regarding this data's use for compliance certifications under Section 114 and title V of the [CAA]." 62 Fed.Reg. at 8314. Further, to clarify the ability of citizens to use any credible evidence (such as in an action under section 304 of the CAA), EPA noted in the CER that "today's rule creates no new rights or powers for citizen enforcers; instead, the rule clarifies existing EPA regulations. Citizens have been free to use credible evidence in [CAA] enforcement and have prevailed in at least two court cases using it." 62 Fed. Reg. at 8318. *See e.g., Sierra Club v. Public Service Company of Colorado, Inc.*, 894 F. Supp. 1455 (D. Colo. 1995); *Unitek Environmental Services, Inc. v. Hawaiian Cement*, 1997 U.S. Dist. LEXIS 19261 (D. HI 1997); *but see, Sierra Club v. TVA*, 430 F.3d 1337 (11th Cir. 2005) (prohibiting a citizen from admitting evidence because Alabama had not adopted the CER into its SIP).

The CER also included changes to federal regulations, notably, 40 C.F.R. § 60.11(g), related to New Source Performance Standards. That regulation specifically provides:

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

40 C.F.R. § 60.11(g).

Further, EPA interprets Kentucky's State implementation Plan, consistent with the 1997 CER, specifically 40 C.F.R. § 51.212(c), as not precluding any entity, including EPA, citizens, or the state, from using any credible evidence to enforce emission standards, limitations, conditions or any other provision of the Kentucky SIP.[5] *See* Letter from Stephen L. Johnson, EPA Administrator, to Robert Ukeiley, June 29, 2007 (Response to Petition for Rulemaking on Credible Evidence Revisions in Kentucky).

Finally, the title V permit here does not preclude the use of any credible evidence in determining compliance with applicable requirements. There is no language in the permit which Petitioner can identify that implies or affirmatively disallows the use of any credible evidence. Furthermore, the absence of language regarding the use of credible evidence in the title V permit does not preclude its use in demonstrating compliance. *See e.g., In the Matter of Motiva Enterprises Final Order*, Petition Number: II-2001-05, dated September 24, 2004; and *In the Matter of Starrett City Final Order*, Petition Number: II-2001-01, dated December 16, 2002. The Spurlock Station permit does not state that Method 9 is the sole or exclusive method used to determine compliance. The permit refers to Method 9 test as the reference test method provided in the SIP for the purpose of determining compliance with the opacity limit. However, as EPA explained in adopting the

[5] The Kentucky SIP also includes language indicating that Kentucky can use "any information" to enforce its SIP. *See, e.g.*, 40 KAR 50:055 (concerning compliance); and 401 KAR 50:060 (concerning enforcement). These two provisions were incorporated into the Kentucky SIP on May 4, 1989 (54 *Fed. Reg.* 19169) and July 12, 1982 (47 Fed. Reg. 30059), respectively. Further, Kentucky's regulations include the incorporation by reference of 40 C.F.R. §§ 60.11 and 61.12 in 401 KAR 60:005, Section 2(1); and 401 KAR 57:002, Section 2(1), respectively. These provisions are not contained in the Kentucky SIP because regulations pertaining to new source performance standards and hazardous air pollutants are not included as part of the SIP for any state.

CER, this means that reference tests, such as a Method 9 test in this case, performed under EPA and State regulations are the benchmark against which to compare other emissions data or parametric data, or engineering analyses, regarding source compliance. *See* 62 Fed. Reg. 8314. Regardless of whether the source chooses to conduct a Method 9 test, the permit requires the source to maintain records of all COMS data which ensures the availability of this data in an enforcement action. In short, nothing in the permit limits EPA, KYDAQ, or citizens from using credible evidence to bring an enforcement action for opacity violations consistent with EPA's 1997 Credible Evidence Rule and Kentucky's SIP.

While the permit allows EKPC to conduct a Method 9 test as a response to an exceedance of the opacity standard, as measured by COMs, EKPC could conduct such a test irrespective of whether the permit specifically allowed it as a response to the opacity exceedance. The permit's provision for a Method 9 test does not change the fact that the COM may measure an exceedance and does not affect the right of EPA, Kentucky or citizen to bring an enforcement action to remedy the exceedance. In short, EPA does not believe this permit provision has any effect on the scope of the evidence that can be utilized in enforcement action, given that Petitioner has not demonstrated that the permit is inconsistent with the Act. EPA denies the petition with respect to this issue.

B. Unit 2 Operating Limits

Petitioner's Comment: Petitioner asserts that the permit appears to require no operating limits for Unit 2 when this Unit should be subject to operating limits carried over from the underlying state issued operating permit. Petitioner points out that the 1976 construction permit application submitted for Unit 2 represented that EKPC would construct and operate a pulverized coal unit with a maximum heat input of 4,850 million British thermal units per hour (mmBtu/hr). Further, this maximum heat input appears in the 1982 and 1983 state issued operating permits covering Unit 2. Petitioner also points out that EPA issued an NOV and filed an enforcement suit against EKPC for violating the 4,850 mmBtu/hr heat input limit (referenced in footnote 1, above). Petitioner asks the Administrator to object to the title V permit because it lacks an enforceable heat input limit.

EPA's Response: Petitioner's primary argument is that the title V permit states "none" under the permit category "Operating Limits" for Unit 2. Petitioner argues that the title V permit, therefore, does not contain an enforceable operating limit. EPA recognizes that there is no maximum heat input limit stated under "Operating Limits" in the title V permit. EPA also notes that the title V permit specifically states in Section G.15, that the title V permit subsumes and incorporates all of the applicable requirements from the existing operating permit. EPA believes this would include the maximum heat input from the underlying state operating permit (SOP).

However, on March 30, 2007, as part of the ongoing EPA enforcement action described above, the United States District Court for the Eastern District of Kentucky ruled that the heat input limit in the underlying SOP ceased to be enforceable upon issuance of EKPC's 1999 title V permit. Specifically, the court stated: "[T]o the extent any term condition, or description in the 1983 SOP was modified by the title V permit or is inconsistent with the title V permit, the later-issued title V permit must control. The Court finds that the reference to the '4850 mmBtu/hr' in the title V permit is just such a term." *United States v. East Kentucky Power Cooperative*, slip op. at 21. The court noted that KYDAQ listed Spurlock Unit 2's maximum heat input as a "description" in the title V permit rather than as a federally enforceable "Operating Limitation." Slip op. at 20-25. The court further ruled that the "description" identifying the "maximum continuous rating" of 4,850 mmBtu/hr listed for Spurlock Unit 2 in the 1999 title V permit was not an enforceable limitation as it appeared in that permit. *Id.* The title V permit that is the subject of this petition contains language similar to the 1999 title V permit. Therefore, according to the ruling of the court, the title V permit does not contain the maximum heat input limit contained in the underlying SOP.

In addition, the use of the term "modified" in the language cited above cannot be read to mean that the heat input limit in the 1983 SOP was not an "applicable requirement" within the meaning of 40 C.F.R. § 70.2, or that the title V permit eliminated the heat input requirement from the 1983 SOP. The title V program does not impose new applicable requirements nor is the title V permitting process the appropriate mechanism for changing or modifying applicable requirements found in underlying permits. Instead, the underlying permit in which the applicable requirement is found must be modified, and then incorporated into the title V permit as an applicable requirement.[6] Thus, the placement of the maximum heat input in the description section of EKPC's 1999 title V permit could not have eliminated the heat input limit as an applicable requirement of the underlying 1983 SOP.

Based on the foregoing, EPA finds that the title V permit is deficient for its failure to include as an applicable requirement the maximum heat input limit found in the underlying 1983 SOP. Therefore, I grant the petition on this issue and direct KYDAQ to amend the permit and to include the applicable heat input limit for Unit 2 under the "Operating Limits" category of the permit.[7]

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[6] To the extent that a state with a merged title V/PSD permitting program (such as Kentucky's) seeks to change applicable requirements in an underlying permit, such changes must be clearly delineated as being made outside of the title V part of the process and the rationale for the change must be clearly stated.

[7] It is apparent the EKPC was aware that the heat input limit was an enforceable limitation in that it previously requested that KYDAQ revise the maximum heat rate for Unit 2 from 4,850 million mmBtu/hr to 5,3555 mmBtu/hr. KYDAQ denied EKPC's request when they informed EKPC that a PSD permit was required for such modification.

EPA wishes to emphasize that its decision to grant Petitioner's request on this issue does not conflict with the proposed consent decree that will resolve EPA's civil enforcement action for EKPC's alleged violations of the maximum heat input limit contained its underlying state operating permit, filed on January 29, 2004. Paragraph 165 of the proposed consent decree requires EKPC to apply for an amendment to its title V permit for the Spurlock Plant that incorporates a maximum continuous rating (MCR) of 5,600 mmBtu/hour. The proposed consent decree does not provide that this MCR replaces the 4,850 mmBtu/hour heat input limit found in its underlying 1983 SOP, nor does it otherwise alter the maximum heat input limit contained in the underlying 1983 SOP.

Further, although the proposed consent decree in paragraph 119 releases EKPC from claims arising from the alleged violations of Parts C and D of the Act, failure to obtain an operating permit that incorporates applicable requirements under the Kentucky SIP, and operation of Spurlock Unit 2 above a maximum heat input of 4,850 mmBtu/hr, the proposed consent decree does not relieve KYDAQ of its obligation under Section 504, 42 U.S.C. § 7661c, and 401 KAR 52.020, to ensure that the Spurlock Unit 2 title V permit contain all applicable requirements under the Act. This includes the maximum heat input limit contained in EKPC's 1983 SOP. Therefore, KYDAQ must amend EKPC's title V permit to incorporate the maximum heat input limit from the underlying state permit or EKPC must apply to KYDAQ under the Kentucky SIP for a permit that would authorize a change in that heat input limit, which in turn would be incorporated in the title V permit.

C. New Source Review (NSR) Compliance Schedule for Unit 2

Petitioner's Comment: Petitioner asserts that the EKPC permit is not in compliance with the CAA because it does not assure that Unit 2 is in compliance with applicable PSD requirements and does not include a compliance schedule to bring the Spurlock Station into compliance with applicable PSD requirements, which are found in the Act and Kentucky's SIP. Petitioner points out that EPA issued an NOV to EKPC for alleged PSD violations at Unit 2 and also filed a complaint in federal district court alleging similar violations. Petitioner asserts that where EPA has issued an NOV alleging CAA violations, the title V permit must include compliance schedules.

EPA's Response: EPA disagrees with Petitioner's conclusion. Petitioner has not sufficiently demonstrated to the Administrator that the permit is out of compliance with the Act, and therefore, EPA denies the petition with respect to this issue.

1. Enforcement and Regulatory History

EPA issued an NOV to EKPC on January 24, 2003, alleging PSD violations at the Spurlock Station. EPA filed a civil complaint in federal district court for the

Eastern District of Kentucky on January 29, 2004, alleging similar violations. *See United States v. East Kentucky Power Coop.* Case No. 04-34-KSF (E.D. KY). The alleged violations at Spurlock Station arose from EKPC's failure to operate Unit 2 in accordance with the stated purpose in its application. EKPC's construction permit application stated that all steam generated by Unit 2 would be used solely to generate electricity. However, in August 1992, EKPC began supplying steam to Inland Container. Further, EPA alleged that the increased steam demand created by connecting to and supplying steam to Inland Container violated the CAA because it resulted in an unpermitted significant net increase of emissions. EPA alleged that EKPC's physical changes constituted "major modifications" as defined in the Act and the Kentucky SIP. This claim flowed from EKPC's decision to uprate the boiler at Spurlock Unit 2, and subsequently operate it at heat input levels above the 4850 mmBtu/hr maximum heat input capacity included in its operating permit. EPA alleged in its NOV and complaint that EKPC did not obtain the required PSD permit prior to constructing or operating these alleged major modifications and has subsequently operated Spurlock station without installing or operating BACT, as required by the Act and the Kentucky SIP. On July 2, 2007, the United States and EKPC lodged a proposed consent decree in the U.S. District Court for the Eastern District of Kentucky. Information regarding the settlement can be found at http://www.epa.gov/compliance/resources/cases/civil/caa/eastkentuckypower.html. Notably, in the proposed consent decree, EKPC has disclaimed liability for the PSD, Kentucky SIP, New Source Performance Standards, and title V violations alleged in the United States' complaint.

As required by title V of the Clean Air Act, part 70, and the Kentucky SIP, EKPC submitted a title V permit application to KYDAQ for its Spurlock Station. Title V requires a facility to include in its application a description of how the facility will comply with all applicable requirements and a schedule of compliance for requirements with which the source is not in compliance at the time of permit issuance. *See* CAA 503(b); 40 C.F.R. § 70.5(c); and 401 KAR 52:020.

EKPC submitted the required title V permit application to KYDAQ; however, EKPC did not include PSD requirements in the application as applicable requirements, nor a compliance schedule, because the company does not believe PSD requirements have been triggered at the plant.

Petitioner requested that KYDAQ include, in EKPC's title V permit, requirements to obtain a PSD permit. Accordingly, Petitioner asserts that since EPA identified violations cited in the NOV and the complaint filed against EKPC the permit must address the violations and include a compliance schedule pursuant to which EKPC is required to obtain the requisite PSD permit and comply with BACT. As explained in the permit's Statement of Basis at page.1, and KYDAQ's Response to Comments, KYDAQ views the issue of PSD applicability as unresolved in light of the on-going litigation and indicated that depending on the outcome of the litigation, it may be required to reopen the permit. Accordingly, KYDAQ did not include PSD requirements in the Spurlock Station permit as applicable requirements.

The Petitioner petitioned EPA to object, under CAA 505(b)(2), to the Spurlock Station permit, and require a compliance schedule. All sources subject to title V must have a permit to operate that assures compliance by the source with all applicable requirements. *See* CAA § 504(a); 40 C.F.R. § 70.1(b). If a source is not in compliance with applicable requirements, then the title V permit must also contain a schedule of compliance leading to the facility's compliance with applicable requirements. *See* CAA § 504(a); 40 C.F.R. §§ 70.1 (b), 70.6(c)(3). Such applicable requirements may include the requirement to obtain PSD permits that comply with applicable PSD requirements under the Act, EPA regulations, and state implementation plans. *See generally* CAA §§ 110(a)(2)(c), 160-69; 40 C.F.R. §§ 51.166, 52.21. If the state permitting authority includes in a title V permit a requirement that the source does not believe applies, the source may, after exhausting any applicable state administrative appeal processes, seek review in state court. That case would involve the source and the state permitting agency, but, absent intervention, not the U.S. EPA.

The Petitioner bases its petition on the fact that the Agency has issued an NOV and filed a complaint in U.S. District Court alleging PSD violations. Petitioner argues that the NOV and the allegations therein, coupled with the complaint, establish the applicability of PSD to Spurlock Station.[8] Petitioner concludes, therefore, that the lack of any PSD requirements or a compliance schedule demonstrates that the permit is not in compliance with the Act, and thus requires the permit to address the violations alleged in the NOV and complaint.

2. Discussion

Contrary to Petitioner's views, and as previously explained by EPA in declining to object to two title V permits issued to Georgia Power Company, the issuance of an NOV and/or the filing of a complaint alone is not sufficient evidence to make the requisite "demonstrat[ion]" under section 505(b)(2). *See generally In the Matter of Georgia Power Company, Bowen Steam – Electric Generating Plant, et al,* Final Order, dated January 8, 2007, at 5-9. Under section 113(a)(1), "[w]henever, on the basis of any information available to the Administrator, the Administrator finds that any person has violated or is in violation of any requirement or prohibition of an applicable implementation plan or permit, the Administrator shall [issue an NOV]." An NOV is simply one early step in the EPA's process of determining whether a violation has, in fact, occurred. It is not a final agency action and is not subject to judicial review. It is well-recognized that no legal consequences flow from an NOV, and an NOV does not have the force or effect of law. *See Pacificorp v. Thomas*, 883 F.2d 661 (9th Cir. 1988); *Asbestec Constr. Servs. v. EPA*, 849 F.2d 765, 768-69 (2nd Cir. 1988); *Union Elec. Co. v.*

[8] In its petition, Petitioner offers no evidence of PSD noncompliance, other than EPA's NOV and the United States' complaint.

EPA, 593 F.2d 299, 304-06 (8th Cir. 1979); and *West Penn Power Co. v. Train*, 522 F.2d 302, 310-11 (3rd Cir. 1975).

A complaint is simply "a pleading which sets forth a claim for relief," and includes a "short and plain statement of the claim that the [plaintiff] is entitled to relief ...." *See* Fed. R. Civ. P. 8(a). While a plaintiff may be subject to sanctions for filing a complaint that includes inaccurate allegations, *see* Fed. R. Civ. P. 11, the complaint does not in-and-of itself prove the facts plead. Rather, as the Eleventh Circuit has noted, when EPA files a complaint in a civil enforcement action, "if the defendant believes that the EPA has reached its conclusions based upon erroneous facts or an incorrect understanding of the law, the defendant may make legal and factual arguments in an independent forum—one that enables the defendant to utilize a panoply of pre-established procedural rights." *See TVA v. Whitman*, 336 F.3d 1236, 1241 (11th Cir. 2003).

Thus, both an NOV and a complaint are initial steps in the process of determining whether the source is in violation of any CAA requirements. These steps are commonly followed by additional investigation or discovery, information-gathering, and exchange of views that occur in the context of an enforcement proceeding and that are considered important means of fact-finding under our system of civil litigation. As a result, EPA believes that the fact of the issuance of an NOV or the filing of a complaint does not definitively establish the necessity of a compliance schedule for title V purposes.

Petitioner also points to the information contained in the NOV allegations, and appears to suggest that such information is sufficient to "demonstrate[]" PSD applicability, under CAA section 502(b)(2). However, information contained in an NOV (or a complaint) alone is not sufficient to demonstrate that a requirement is applicable for permitting purposes. EPA may consider an NOV's filing or complaint's issuance as a relevant factor when determining whether the overall information presented by the petitioner – in light of all the factors that may be relevant – demonstrates the applicability of a requirement for title V purposes. Other factors that may be relevant in this determination include the quality of the information, whether the underlying facts are disputable, the types of defenses available to the source, and the nature of any disputed legal questions, all of which would need to be considered within the constraints of the title V process. If, in any particular case, these factors are relevant and the Petitioner does not present information concerning them, then EPA may find that the Petitioner has failed to present sufficient information to demonstrate that the requirement is applicable.

Another factor that EPA considers is the potential impact enforcement cases and title V decisions have on one another, as illustrated by the following example. As is the case here, EPA could bring a civil judicial enforcement action for violations by a source of a substantive rule. The source and EPA would be engaged in litigation over the merits of the allegations of EPA's judicial complaint. Should EPA prevail in that enforcement proceeding, or should the source and EPA propose to settle their differences – as has happened in this particular enforcement proceeding – then the court would enter judgment in the form of an order or consent decree requiring the source achieve compliance with the law either pursuant to the terms of a compliance order, or, at a minimum, by a date certain. (*In the Matter of Georgia Power Company, Bowen Steam – Electric Generating Plant, et al Final Order*, dated January 8, 2007; and *In the Matter of Lovett Generating Station Final Order*, Petition Number: II-2001-07, dated February 19, 2003). In the event of a proposed settlement, the enforcement proceeding would not be "final" or concluded until such time that the consent decree is entered by the court. Thus, should the proposed consent decree be entered by the court in the related enforcement action, KYDAQ and EKPC would need to appropriately respond by incorporating the compliance schedule(s) required by the consent decree into the title V permit. Specifically, the proposed consent decree requires EKPC to amend its title V permit within 180 days of entry of the consent decree to "include a schedule for all Unit-specific performance, operational, maintenance, and control technology requirements established by this consent decree including, but not limited to, emission rates, removal efficiencies, fuel limitations, tonnage limitations, and the requirement in Paragraph 72 pertaining to the surrender of SO_2 Allowances." Proposed Consent Decree, ¶ 166.

Separately, in the context of the issuance of a title V permit to the same source, the permitting authority may determine (on its own or as a result of an EPA objection) that the source is in non-compliance with the substantive rule (i.e., applicable requirement) that is the subject of the enforcement proceeding, and require in the title V permit that the source achieve compliance with the applicable requirement pursuant to a schedule of compliance. Under such circumstances, the source could challenge the permit, petition EPA for relief, and appeal to the appropriate circuit court. In these circumstances, the source and EPA could find themselves in two separate forums for litigating essentially the same issues - whether the substantive rule was violated and the appropriateness of a compliance schedule – which risks potentially different and conflicting results.

In light of the settlement lodged but not yet entered in the federal court enforcement action between the United States and EKPC, the fact that EKPC continues to dispute its PSD liability notwithstanding reaching that settlement with the United States, and Petitioner's sole reliance on the existence of an NOV and complaint in the enforcement action, I find that the petition does not "demonstrate" that the title V permit does not comply with the Clean Air Act. At this point, the PSD claims in the complaint have not been fully adjudicated and the proposed consent decree has not yet been entered in federal court, and thus, Petitioner has not met its burden of showing that the permit is not in compliance with the Act.

I note that, while the permit does not contain PSD as applicable requirements for Unit 2, it also does not provide any safe harbor from enforcement of PSD requirements. Thus, the permit does not disturb any ongoing or future enforcement action against EKPC for violations of PSD requirements.[9] EPA believes that, considering these specific circumstances it would be premature to make a determination on PSD applicability and any NSR compliance schedule requirements. The appropriate path is to allow the PSD applicability issue to be fully resolved by the federal district court in the enforcement process before determining that the title V permit must contain such requirements.

For the reasons explained herein, EPA denies the petition with respect to this issue.

D. Construct and Operate Unit 3 in Accordance with Permit Application

Petitioner's Comment: Petitioner asserts that the permit omits a requirement that EKPC construct and operate Unit 3 in accordance with the plans and specifications submitted with the pre-construction permit application. The CAA and requires that a PSD applicant construct and operate the source consistent with the specifications of the permit application. 40 C.F.R § 52.21(r). This includes, but is not limited to, the fuel, control equipment, and maximum heat rating included in the permit application. Petitioner is requesting that the Administrator object to the permit and require that it be revised to include these requirements.

EPA's Response: EPA disagrees with Petitioner's conclusion. The permit is written based on the specifications, terms and conditions of the application submitted by EKPC, and as a pre-requisite, that application must be complete and accurate in order to comply with the applicable regulations. 401 KAR 52:020. Petitioner's reliance on 40 C.F.R § 52.21(r) to argue that the CAA requires that a PSD applicant construct and operate the source consistent with and according to the specifications provided in the permit application is misplaced – that regulation governs federally issued or delegated PSD permits. For Kentucky, which issues PSD permits pursuant to a federally approved SIP, the applicable and relevant federal regulation is set forth at 40 C.F.R. § 51.166(r)(1), which states that the SIP for an approved PSD program "shall include enforceable procedures to provide that approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provisions of the plan and any other requirements under local, State or Federal law." While Petitioner correctly notes the relevant state PSD law, Petitioner fails to recognize that under that law, the source must be operated "in accordance with the application [to construct]... or under the terms of an approval to construct." 401 KAR 51:017(16) (emphasis added). Because a PSD source in Kentucky that operates in accordance with its permit to construct has met

[9] In the ongoing case, *U.S. v East Kentucky Power Cooperative*, Case No. 04-34-KSF (E.D. KY), the Sixth Circuit recently ruled that EPA had not proven in its *Motion for Summary Judgment*, when and how frequently EKPC exceeded the 4,850 mmBtu/hr limit, therefore, that issue would have to be addressed at a future trial. The Court also ruled that EPA had not met its burden of proof required to establish the relationship between EKPC's uprating its boilers to 4 million pounds per hour of steam and an alleged corresponding increase in the heat input to the boiler.

the requirements of the applicable state and federal law, it is not necessary for KYDAQ to include language in the title V permit requiring EKPC to construct and operate Unit 3 consistent with the specifications of the PSD permit application. Therefore, EPA denies the petition with respect to this issue.

E. BACT Limits for Unit 3

Petitioner's Comment: As a general matter, Petitioner claims BACT limits established in prior title I permitting actions can be revisited in subsequent title V permitting processes if it is established that the historic BACT determination was erroneous. With regard to the Spurlock Station title V permit, Petitioner alleges that the permit contains erroneous BACT limits for Unit 3, and relies heavily on EPA's Order *In re Chevron Products Co.*, Petition No. IX-2004-08 (*Chevron*), to substantiate its claim.

EPA's Response: The Petitioner has failed to demonstrate that the Spurlock Station title V permit for Unit 3 is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA Section 505(b)(1). Further, as stated in *Chevron*, pursuant to EPA policy, the Agency generally does not object to the issuance of a title V permit due to concerns over BACT or related determinations made long ago during a prior reconstruction permitting process. *Id.* at 9; *see also* Letter to John S. Seitz to Robert Hodanbosi and Charles Lagges at page 2 (May 20, 1999).

Notwithstanding EPA's general policy not to object to the issuance of a title V permit due to concerns over BACT determinations made during a prior reconstruction permitting process, EPA clearly retains its authority to reopen a permit to reevaluate BACT determinations under limited circumstances. Specifically, EPA will reopen a permit when an emissions limit unit has not gone through the proper PSD permitting process, and therefore lacks one or more applicable requirements of the CAA in the draft or proposed title V permit. *See Chevron* at 11 n13. EPA exercised its authority on this basis to reopen the Chevron permit because the BACT limits were adopted under local district rules that were not approved by EPA and that provided an exemption from NSR requirements. The local district adopted the rule exemption 11 months prior to the submittal of Chevron's application and deleted it within two months after approving construction of the Chevron unit in question. Consequently, EPA concluded that there was insufficient information to make a determination as to whether the Chevron permit limits accurately reflected BACT or whether the NSR requirements were followed. However, in granting the *Chevron* title V petition on the BACT issue, EPA made it abundantly clear that it was doing so solely because the specific facts demonstrated degrees of deficiency and a possible compromise in the PSD permitting process. *See id.* at 11-13 and n13.

The scenario presented in this petition concerning the BACT limits for Unit 3 is quite distinguishable from *Chevron*. KYDAQ adopted the Unit 3 limits under an EPA approved PSD program, and EPA and the public were given the opportunity to review and comment on these limits prior to the issuance of the final PSD permit in June 2002. At that juncture, Petitioner clearly had the opportunity to raise its concerns regarding the BACT limits for Unit 3, but for unknown reasons, it failed to do so. In this instance, Petitioner has not demonstrated, and there is nothing in the record to suggest any deficiency in the PSD permitting process or that Unit 3 BACT determination was unreasonable. (The Supreme Court held that EPA may act to block construction of a new major pollutant emitting facility if EPA finds that the state's BACT determination was unreasonable.) *Alaska Dep't of Environmental Conservation v. EPA*, 540 U.S. 461, 488 (2004). In addition, Petitioner has failed to demonstrate that the title V permit including the Unit 3 BACT limits, is not in compliance with the applicable CAA requirements.

For these reasons, and as explained more fully below, EPA denies the petition with respect to this issue.

1. Visible Emission BACT Limits

Petitioner's Comment: Petitioner claims the permit does not contain visible emission BACT limits for PM and sulfuric acid mist (SAM) from Unit 3. Any new or modified major source must have a permit requiring BACT and BACT is expressly defined as an "emissions limitation including a visible emission standard," for each "regulated NSR pollutant." 401 KAR 51:001, Section 1(25).

EPA's Response: Consistent with KYDAQ's Response to Comments, EPA concludes that opacity is not an NSR regulated pollutant, and thus, there is no applicable federal or state requirement to have a BACT opacity limit. *See* KYDAQ's Response to Comments at page 46; *see also Knauf Fiber Glass,* 8 E.A.D. 121 (EAB 1999) (stating that an opacity limit "is not a requirement of the federal PSD program"). It is permissible for an agency to use opacity as an emission limitation. Contrary to Petitioner's assertion, the inclusion of visibility in the definition of BACT merely clarifies that a visible emission standard is an acceptable form of a BACT limit for an NSR regulated pollutant. *See Alabama Power v. Costle*, 636 F.2d 323, 408 (D.C. Cir. 1979) (emphasis added). Accordingly, opacity may be used as an indicator of particulate matter, fumes, gases or vapor but it is not independently regulated. This position is consistent with EAB and state decisions finding that PSD does not necessarily require opacity limits. *See generally In re Amerada Hess Corp. Port Reading Refinery*, PSD Appeal No. 04-03, slip op. at 11 (EAB Feb. 1, 2005); *In re Air Pollution Control Construction and Operation of a 500 MW Pulverized Coal-Fired Plant Known as Weston Unit 4* in Marathon County, Wisconsin, Wis. Div. of Hearing and Appeals, Case No. IH-04-21 (Feb. 10, 2006). The Spurlock permit as written provides direct and specific limits for the pollutants identified by Petitioner (PM and SAM). Further, the regulated NSR pollutant PM/PM_{10} will also be monitored by PM continuous emission monitoring system (CEMS), thus providing a continuous method for ensuring compliance with the particulate emissions standards. Because opacity is not an NSR regulated pollutant, and there is not an applicable federal or state requirement to have a BACT opacity limit, EPA denies the petition with respect to this issue.

2. Sulfur Dioxide (SO_2) Limit

Petitioner's Comment: The SO_2 limit for Unit 3 does not represent BACT as of June 2002, when construction commenced on Unit 3. Other permits issued prior to the time construction commenced on Unit 3, contain much lower SO_2 limits. Therefore, these lower limits must be presumed to be BACT for Unit 3 since EKPC has not demonstrated that it is technologically infeasible.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the SO_2 limit for Unit 3 contained in this title V permit is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA § 505(b)(1). Based on the record before the Agency, the existing SO_2 limit for Unit 3 contained in this title V permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ Response to Comments at page 32. As explained above, the Agency generally will not object to a title V permit due to concerns over BACT determination made in a prior PSD preconstruction permitting process. *See discussion* Section E, *supra.*

As a basis for its position, Petitioner provides examples of lower limits established for SO_2 at similar sources throughout the country. However, Petitioner fails to provide any analysis to demonstrate that these BACT limits are appropriate for Unit 3. The other sources that Petitioner references are distinguishable from Unit 3 based on several factors, including plant size and fuel type. It is well recognized that due to characteristics of individual plant processes, the application of identical technology may not yield identical emission limits. *See Newmont Nevada Energy Investments, LLC TS Power Plant,* PSD Appeal No. 05-04, slip op. 16-17 (EAB Dec. 21, 2005); *In re. Knauf Fiberglass GmbH,* 8 EAD at 143 (EAB 1999). Petitioner refers to the PSD permit for the AES Puerto Rico facility without pointing out that the AES permit has a specific and distinguishable condition that limits the fuel the source can burn to a maximum of 1 percent sulfur. Spurlock Unit 3 has no such limits and is permitted to burn coal in the 4.5 percent sulfur range. In arguing that the limit in the AES Puerto Rico permit is BACT for Unit 3, Petitioner disregards the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. Petitioner has failed to establish that KYDAQ's BACT determination for the SO_2 limit was unreasonable, or otherwise not in compliance with the applicable CAA requirements. *See generally Alaska Dep't of Environmental Conservation,* 540 U.S. 461, 488 (2004). For these reasons, EPA denies the petition with respect to this issue.

3. Particulate Matter (PM) Limit

Petitioner's Comment: The PM limit for Unit 3 does not represent BACT for Unit 3 as of the date of construction on June 22, 2002. Other permits issued prior to the commencement of Unit 3's construction contain much lower PM limits, and therefore, these lower limits must be presumed to be BACT for Unit 3 unless EKPC demonstrates that such limits are not technically feasible or cost effective.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the title V permit is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA, Section 505(b)(1). The existing PM limit established in the permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ Response to Comments at page 33. Further, the Agency generally will not object to a title V permit due to concerns over BACT determination made in a prior PSD preconstruction permitting process. *See discussion* Section E, *supra.*

As a basis for claiming that the Unit 3 PM limit of 0.015 lb/mmBtu (filterable) does not represent BACT, Petitioner references another source (Northampton facility) that is similar to Unit 3 but fails to recognize that the source has characteristics that influence PM emissions and are distinct from Unit 3, such as fuel type (i.e., Northamption burns anthracite as opposed to high sulfur bituminous coal used in Spurlock Unit 3). *In re BP Cherry Point*, PSD Appeal No. 05-01, slip op. 21 (EAB June 21, 2005); and *In re Prairie State Generating Co.* PSD Appeal No. 05-05 slip op. at 71 (August 24, 2006). Moreover, Petitioner neglects to mention that the PM limit for Unit 3 is actually lower than some limits imposed on other similar facilities (AES Beaver Valley and Archer Daniel Midland) prior to June 2002. Overall, Petitioner fails to provide any analysis to demonstrate that its preferred PM BACT limit for this pollutant is appropriate for Unit 3 and in so doing, Petitioner continues to disregard the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. In its petition, the Petitioner has failed to establish that KYDAQ's BACT determination for PM limit was unreasonable for Unit 3, or otherwise not in compliance with the applicable CAA requirements. *See generally Alaska Dep't of Environmental Conservation,* 540 U.S. 461,488 (2004). For these reasons, EPA denies the petition with respect to this issue.

4. Nitrogen Oxides (NO_x) Limit

Petitioner's Comment: The NO_x limit for Unit 3 does not represent BACT for Unit 3 as of the date of construction on June 22, 2002. Other permits issued prior to the commencement of Unit 3's construction contain much lower NO_x limits and therefore, these lower limits must be presumed to be BACT for Unit 3 unless EKPC demonstrates that such limits are not technically feasible or cost effective.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the title V permit is not in compliance with the applicable CAA requirements, including the requirements of the Kentucky SIP. CAA § 505(b)(1). The existing NO_x limit established in the permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ Response to Comments at page 33. As explained previously, the Agency generally will not object to a title V permit due to concerns over a BACT determination made in a prior PSD preconstruction permitting process. *See discussion* Section E, *supra.*

As a basis for its position that the Unit 3 NO_x limit of 0.07 lb/mmBtu does not represent BACT, Petitioner provides examples of lower limits established for NOx at facilities that use boilers similar to Spurlock Unit 3, but Petitioner fails to recognize that these other facilities have striking differences that distinguish them from Unit 3. For instance, the BMCP facility cited by Petitioner is a 20 megawatts (MW) facility burning 0.6 percent sulfur coal, while Unit 3 is a 270 MW unit burns high sulfur bituminous coal. Moreover, Petitioner fails to acknowledge that the NO_x limit for Unit 3 is consistent with the NO_x limits imposed on similar facilities (NEVCO-Sever, Kentucky Mountain Power and JEA Northside). In presenting its position, Petitioner does not provide any analysis to demonstrate that its preferred BACT limits for NO_x is appropriate for Spurlock Station Unit 3. In so doing, Petitioner continues to disregard the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. Because Petitioner has failed to establish that KYDAQ's BACT determination for the NO_x limit was unreasonable for Unit 3, or otherwise not in compliance with the applicable CAA requirements, EPA denies the petition with respect to this issue.

5. SAM Limit

Petitioner's Comment: The SAM limit for Unit 3 does not represent BACT for Unit 3 as of the date of construction on June 22, 2002. Other permits issued prior to the commencement of Unit 3's construction contain much lower SAM limits and therefore, these lower limits must be presumed to be BACT for Unit 3 unless EKPC demonstrates that such limits are technically infeasible or not cost effective.

EPA's Response: As stated above, Petitioner has failed to demonstrate that the title V permit is not in compliance with the applicable CAA requirements, including the requirements of an applicable implementation plan. CAA § 505(b)(1). The existing SAM limit established in the permit represents BACT for Unit 3. This BACT determination was made during a prior permitting action, at which time Petitioner had the opportunity to raise the issue but failed to do so. *See* KYDAQ's Response to Comments at page 33. Further, the Agency generally will not object to a title V permit due to concerns over BACT determination made in a prior preconstruction process. *See discussion* Section E, *supra.*

As a basis for claiming that the Unit 3 SAM limit of 0.07 lb/mmBtu does not represent BACT, Petitioner references another source (AES Puerto Rico) that is similar to Spurlock Unit 3, but AES Puerto Rico is clearly distinguishable based on the sulfur content of the fuel. Again, Petitioner disregards the "case-by-case" site specific nature of the BACT analysis. CAA § 169(3) and 401 KAR 51.001. Petitioner references the SAM limit contained in the AES Puerto Rico PSD permit but fails to take in consideration that this limit is based on the low sulfur content of the fuel that is also required by the permit. As stated above, Unit 3 has no such limits on coal sulfur content, and is permitted to burn coal in the 4.5 percent sulfur range. Based on these circumstances, the SAM limit for Unit 3 is entirely consistent with other permits where the facility is burning a higher sulfur coal (e.g., Greene Energy Recovery Project, Permit No. PA-30-00150, burning high sulfur waste coal with a 0.0060 lb/mmBtu limit). Since Petitioner has failed to establish that KYDAQ's BACT determination for the SAM limit was unreasonable for Unit 3, or otherwise not in compliance with the applicable CAA requirements, EPA denies the petition with respect to this issue.

F. Enforceable Limits and Monitoring to Ensure Continuous Compliance For Unit 3

Petitioner's Comment: Petitioner claims that the limits for Unit 3 are not enforceable and do not require monitoring to ensure continuous compliance. A title V permit must require monitoring sufficient to ensure that the source is in continuous compliance with the permit limits during the relevant time periods. 40 C.F.R. § 70.6(a)(3)(i)(B). This permit contains insufficient monitoring to ensure compliance with PM and hazardous air pollutant (HAP) limits, including hydrogen fluoride (HF). The permit establishes opacity as a surrogate for PM/PM_{10} compliance and if the source violates the opacity surrogate it is required to conduct a stack test. However, the permit does not explicitly state that a violation of the opacity surrogate range is a violation of the PM limit. In addition, an annual stack test is insufficient to insure compliance with the HAPs limits.

EPA's Response: Petitioner requests that the Administrator object to the permit and require KYDAQ to modify the permit to explicitly state that: (1) COMs can be used to establish violations of the opacity limit, and (2) exceedance of the Compliance Assurance Monitoring (CAM) level for opacity is a violation of the PM standard, in addition to triggering corrective action under the CAM rule. However, EPA has determined that Petitioner's request is inconsistent with the requirements of CAM, Kentucky's SIP and title V. As explained previously, an agency may use opacity as an emission limit for an NSR regulated pollutant but there is no federal or state requirement to have an opacity limit in a permit other than those contained in the applicable CAM regulation. Petitioner's comment fails to recognize that exceedance of the CAM level for PM or HAPs monitors is not a permit violation, but rather a trigger for corrective action under the CAM rule.

Notwithstanding Petitioner's assertion, pursuant to the CAA §§ 114(a)(3), and 504(c), a title V permit is required to provide for "enhanced monitoring" and submission of compliance certification. In *Natural Resources Defense Council, Inc. (NRDC) v. EPA,* 194 F.3d 130 (D.C. Cir.1999), the court confirmed that CAM standards assured compliance as required by the CAA. "CAM enhances monitoring by requiring each major source owner to design a site-specific monitoring system sufficient to provide a reasonable assurance of compliance with emissions standards." *Id.* If CEMS or COMS is required, the Act requires that the source use that system to satisfy the CAM rules. 40 C.F.R. § 64.3(d). In the absence of continuous monitoring, CAM requires that indicators be established to provide an indication of whether or not a control device is working properly. 40 C.F.R. § 64.3(a).

With regard to Unit 3, since a PM CEMS has not yet been installed at Unit 3, opacity is selected as an indicator of PM compliance, as are electrostatic precipitator (ESP) transformer/rectifier set voltages and currents. This is consistent with 40 C.F.R. § 64.3(d), which states in part that "if an opacity standard applies to the pollutant-specific emissions unit, such limit may be used as the appropriate indicator." Since the specific voltage and current levels that indicate proper levels of ESP performance will vary from unit-to-unit, CAM requires testing at Unit 3 to establish the opacity level that will be used as an indicator of particulate matter emissions. As the permit states "the opacity indicator level shall be established at a level that PM emissions are in compliance when opacity is equal to or less than the indicator level." Permit at B4(b) and 40 C.F.R. § 64.4(c)(1).

Petitioner's assertion that EKPC's excess emissions of opacity should be independently considered as violations of the PM standard is unsubstantiated. The Petitioner fails to demonstrate where the permit is lacking enforceable terms and conditions. The permit requires EKPC to install COMS, which includes installing, calibrating, operating, and maintaining the continuous monitoring system for accurate opacity. *Id* at B4(a). The permit clearly sets forth that the source will monitor COMS readings and record pressure drop across the baghouse once per shift, and Unit 3 is also subject to recordkeeping and reporting requirements. Regarding opacity, the permit requires that the source conduct tests to establish the level of opacity that will be used as an indicator of PM emissions. *See id* at B4(b). Pursuant to 40 C.F.R § 64.4(e), the source is required to conduct initial performance tests within 180 days of the permit issuance to establish the opacity and PM correlation, pursuant to 40 C.F.R § 64.4(e). Similarly, the permit requires EKPC to conduct an initial performance test to establish the parameter monitoring for the control device and upon completion of the initial performance test, the appropriate monitoring range will be incorporated into the permit. EPA has consistently found the combination of parametric monitoring for control of PM, monthly opacity reading, testing and reporting to be adequate. *See e.g., In the Matter of GCC Dacotah Cement Manufacturing Plant Final Order,* Petition Number: VIII-2006-03 at page 10 (June 2007).

Pursuant to 40 C.F.R. § 64.4(c)(1) and the CAM plan filed on October 27, 2005, opacity must be used as an indicator of PM emissions in conjunction with monitoring of the ESP's transformer/rectifier voltage and current levels. As stated above, in order to provide reasonable assurance that PM emissions are in compliance, the permit establishes opacity (20 percent) at a range that is set well below the limit which would constitute a violation. *See* B4(m)(ii) and 40 CFR § 64.4(c)(1).

Further, Petitioner's assertion regarding the lack of monitoring for HAPs limits, including HF, is also incorrect. The permit specifies methods for ensuring compliance with applicable requirements for volatile HAPs, mercury, hydrogen chloride, HF, beryllium, lead and metals. *Id.* In accordance with CAM, the permit requires EKPC to conduct annual stack tests and to use a "grab bag" sampling of the fuel content to establish correlation between HAP content and HAP emissions. EPKC is required to demonstrate compliance with these emission limits annually to validate the correlation between grab samples HAP content and HAP emissions. After three years of demonstrating compliance and correlation between the samples and emissions, the permit affords EKPC the opportunity to use the quarterly grab samples as a surrogate for compliance testing. However, the permit indicates that the annual stack testing not the "grab samples" will be used to determine a violation of the emission limit. Further, the permit states that the compliance with the sulfur dioxide emissions indicates compliance with HF limits. The emission unit uses a dry lime scrubber to control the SO_2 and HF emissions by injecting lime into the scrubber line. The permit requires the source to conduct a performance test to determine a lime injection rate and this method will be used to determine continuous compliance with the HF emission limit.

The position taken by Petitioner that the permit must specify "enforceable limits" for each of the monitored parameters is also not supported by the final CAM rule. As EPA explained in the preamble to that rule,

> The CAM approach builds on the premise that if an emissions unit is proven to be capable of achieving compliance as documented by a compliance or performance test and is thereafter operated under the conditions anticipated and if the control equipment is properly operated and maintained, then there will be a reasonable assurance that the emissions unit will remain in compliance. In most cases, this relationship can be shown to exist through results from the performance testing without additional site-specific correlation of operational indicators with actual emission values ...
>
> ... the presumptive approach for establishing indicator ranges in part 64 is to establish the ranges in the context of performance testing. To assure that conditions represented by performance testing are also generally representative of anticipated operating conditions, a performance test should be conducted under conditions specified by the applicable rule or, if not specified, generally under conditions representative of maximum emission

> potential under anticipated operating conditions. In addition, the rule allows for adjusting the baseline values recorded during a performance test to account for the inappropriateness of requiring that indicator conditions stay exactly the same as during a test. The use of operational data collected during performance testing is a key element in establishing indicator ranges; however, other relevant information in establishing indicator ranges would be engineering assessments, historical data and vendor data. Indicator ranges do not need to be correlated across the whole range of potential emissions.

62 Fed. Reg. 54909, 54926 (October 22, 1997). In addition, EPA has explained that established CAM parameters are not enforceable limits. The CAM rule preamble addressed this by pointing out that:

> The obligation to correct excursions as expeditiously as practicable is the enforceable component associated with establishing an indicator range under part 64. Part 64 does not establish that an excursion from an indicator range constitutes an independent violation by itself.

Id. 54931. *See also id* at 54928. Thus, CAM provides a reasonable assurance of compliance with emission limits and consequently, the adoption of CAM as "enhanced monitoring" meets the requirement of the CAA but does not convert the CAM parameters to enforceable permit limits. Accordingly, EPA denies the petition with respect to this issue.

G. BACT Limits for Unit 4[10]

In arguing that the Unit 4 BACT limits are not in compliance with the PSD requirements of the Clean Air Act, Petitioner describes the BACT selection process, but EPA has determined that Petitioner's arguments concerning the BACT limits for Unit 4 fail to consider the critical "case-by-case" analysis that defines BACT. CAA § 169(3) and 401 KAR 51.001. PSD permit decisions depend heavily on site-specific analysis, and this case-by-case decision-making inevitably results in substantive differences from permit to permit. *See In re Cardinal FG Co.*, PSD Appeal No. 04-04, slip op. at 11 (Explaining that "BACT is a site-specific determination); *In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 788-89 (Adm'r1992) ("PSD permit determinations are made individually under the Act on a case-by-case basis"). Petitioner further ignores that a BACT analysis does not necessarily yield a single objective and correct BACT determination that can be applied to all plants. *See Alaska Dept. of Environmental Conservation.* 540 U.S. 461, 488 (2004). BACT is a site-specific determination resulting in the selection of

[10] Unlike the BACT issues regarding the previously permitted Unit 3, *see* Section E *supra*, EPA policy has maintained the Agency's discretion to object to the issuance of a title V permit due to concerns over BACT when the PSD process is merged with the title V process. *See* Letter to John S. Seitz to Robert Hodanbosi and Charles Lagges at page 2 (May 20, 1999).

an emission limitation that represents application of control technology appropriate for the particular facility. *See In re Three Mountain Power*, LLC, 10 E.A.D. 39, 47 (EAB 2001).

As evidenced in EPA's response to Petitioner's BACT Unit 3 challenge, *see* section IV.E., *supra,* Petitioner continues to overlook the fact that a BACT analysis may consider certain distinguishable factors at a particular facility when setting emission limit, *inter alia*, the type of fuel that will be used, type of source, size of the source and geographic considerations. A high degree of technical judgment must also be exercised in any BACT analysis for coal-fired plants given the wide variety of coals (e.g., anthracite and sub-bituminous) and coal-fired facilities (e.g., pulverized coal, and CFB) available for permitting authorities to consider. *In re BP Cherry Point*, PSD Appeal No. 05-01 slip op. at 71 (EAB June 21, 2005); *In re Prairie State Generating Co*., PSD Appeal No. 05-05 slip op. at 71 (EAB August 24, 2006).

While EPA agrees with Petitioner's position that BACT requires a forward-looking analysis, BACT also takes into account that the selected limit must be "achievable for such facility." *Newmont Nevada Energy Investments, LLC TS Power Plant*, PSD Appeal No. 05-04, slip op. 16-17 (EAB Dec. 21, 2005). Several EAB decisions reflected this position and explained that "the underlying principle of all these PSD cases is that PSD permit limits are not necessarily a direct translation of the lowest emissions rate that has been achieved by a particular technology at another facility, but those limits must also reflect consideration of any practical difficulties associated with using the control technology." *In re Kendall New Century Dev.*, PSD Appeal No. 03-01, slip op. at 17 (EAB April 29, 2003); *Three Mountain Power,* 10 E.A.D at 38 and 47. The permit issuer must be given some flexibility and "may take into account the absence of long-term data, or the unproven long-term effectiveness of the technology, in setting emissions limitation that is BACT for a facility." *Newmont,* slip op. at 18; and *In re Cardinal FG Co.*, PSD Appeal No. 04-04 (EAB Mar. 22, 2005). The Supreme Court has made it clear that "Congress entrusted state permitting authorities with the initial responsibility to make BACT determinations 'case by case' § 7479(3). *See Alaska Dept. of Environmental Conservation.* 540 U.S. 461, 488 (2004). A state agency, no doubt, is best positioned to adjust for local differences in raw materials or plant configurations, differences that might make a technology 'unavailable' in a particular area." *Id.*

Regarding Petitioner's reliance on the draft NSR Workshop Manual (NSR manual), the EAB has ruled that although the NSR manual provides a framework that assures adequate consideration and consistency within the PSD permitting program, it is not a binding Agency regulation and as such, strict application of the methodology described therein is not mandatory. *In re Tondu Energy Co*., 9 E.A.D. 710, 719 (EAB 2001); *In re Steel Dynamics, Inc*., 9 E.A.D. 165, 183 (EAB 2000); *Three Mountain Power* at 42. Since the NSR manual has not been incorporated in the Kentucky SIP, as long as the state conducts careful and detailed analysis of the criteria identified in the regulatory definition of BACT, KYDAQ is not required to strictly adhere to the manual.

1. Sulfur Dioxide (SO_2) BACT Limits and Low Sulfur Coal

Petitioner's Comment: Petitioner claims that the BACT determination for Unit 4 failed to consider lower sulfur coal as a method to reduce sulfur dioxide (SO_2) emissions. EKPC and KYDAQ are required to determine whether lower pollution rates could be achieved by switching to a cleaner fuel. EKPC attempted to justify an SO_2 BACT limit higher than the limits set for similar facilities by relying on the fact that Unit 4 will use high sulfur coal, but its own analysis shows that using Powder River Basin (PRB) coal or low-sulfur eastern bituminous coal as the fuel for Unit 4 would reduce SO_2 emissions by 1,700 or more tons per year and would be cost effective.

EPA's Response: In reviewing Petitioner's request that the Administrator object to the permit because it does not include an accurate BACT limit for SO_2, EPA reviewed the BACT determination provided by KYDAQ and EKPC. Without deciding the merits of Petitioner's claim regarding the cost effectiveness of the various coal options considered by for Unit 4, EPA has determined that EKPC and KYDAQ have not provided an adequate explanation for their determination that the design basis coal is the BACT fuel for Unit 4. In particular, EPA finds that KYDAQ and EKPC have failed to provide a complete justification for excluding low sulfur eastern bituminous coal as BACT for limiting SO_2 emissions from this project. Accordingly, the Administrator grants the petition on the narrow issue of the selection of SO_2 BACT, limits and directs KYDAQ and EKPC to provide a complete analysis to support the selection of the design coal as BACT.

EPA has traditionally utilized a 5-step, top-down process for determining whether BACT emission limits for each PSD-regulated pollutant considered in a permitting decision meet the statutory criteria: (1) identify all potentially applicable control options (2) eliminate technically infeasible control options; (3) rank remaining technologies by control effectiveness; (4) eliminate control options from the top down based on energy, environmental, and economic impacts; and (5) select the most effective option not eliminated as BACT. *See In re Prairie State Generating Co.*, 13 E.A.D. ___, PSD Appeal No. 05-05, slip op. at 14-18 (EAB Aug. 24, 2006) (summarizing and describing steps in the top-down BACT analysis). *Accord In re Three Mountain Power, L.L.C.,* 10 E.A.D. 39, 42-43 n.3 (EAB 2001); *In re Knauf Fiber Glass, GmbH,* 8 E.A.D. 121, 129-31 (EAB 1999); and *In re Hawaii Electric Light Co.,* 8 E.A.D. 66, 84 (EAB 1998). In this case, EKPC and KYDAQ used this 5-step, top-down process to determine the BACT emission limits, including the SO_2 limit, contained in the permit for Spurlock Unit 4. *See* EKPC Supplemental BACT Analysis for Spurlock Unit 4 (January 12, 2006) at 2-5 (describing this process as its "BACT Methodology"); and KYDAQ Permit Statement of Basis (February 3, 3006) at 22 (explaining that BACT limits for Unit 4 were determined by using EKPC's BACT analysis).

In responding to Petitioner's previous comments regarding the use of lower sulfur coals in determining the SO_2 BACT for Unit 4, KYDAQ said it did not "concur that a limit restricting the coal sulfur content is appropriate or necessary for this type of unit, nor is the Division aware of any other permits for this type of facility that contain a limit in the percentage of sulfur that the fuel can contain." KYDAQ's Response to Comments (June 1, 2006) at 54; *see also* KYDAQ Permit Statement of Basis at 23-24 (describes the BACT limit for SO_2 without any discussion of coal choice or coal sulfur content). This response is insufficient because it does not provide any explanation as to why KYDAQ did not consider selection of a lower sulfur coal "appropriate or necessary" for achieving BACT at Unit 4 based on the applicable permitting criteria.[11] While permitting authorities have discretion in making the case-by-case technical assessments necessary to determine BACT for a specific source, in exercising that discretion, they must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations. *See Indeck-Elwood*, 13 E.A.D. ___, PSD Appeal No. 03-04, slip op. at 29 (EAB Sept. 27, 2006) ("A permit issuer must, therefore, articulate with reasonable clarity the reasons for its conclusions and must adequately document its decision making.") and cases cited therein. Accordingly, in order to justify the SO_2 BACT selected for this project, KYDAQ needs to provide additional analysis and/or a justification for its determination that use of lower sulfur coal was not an achievable option for Spurlock Unit 4. *See Inter-Power of New York*, 5 E.A.D. 130, 145-49 (EAB 1994) (upholding PSD permit for a CFB boiler where petitioners claimed lower sulfur coal would have been used, but where the record showed that the permit's SO_2 limit was within the range of SO_2 limits of similar projects that had recently been issued PSD permits).

Given that KYDAQ's Permit Statement of Basis explains that BACT limits for Unit 4 were determined after considering the applicant's BACT analysis, *id.* at 22, EPA has also examined EKPC's SO_2 BACT analysis to determine if it provides an adequate basis for selection of the design basis coal as BACT, *see* EKPC Supplemental BACT Analysis for Spurlock Unit 4 (January 12, 2006) at 5-8. Upon complete examination, EPA finds that EKPC's analysis is also deficient because it does not explain (based on the BACT criteria) why one coal type – low sulfur eastern bituminous coal – was excluded as BACT for this project. Using the 5-step, top-down process for determining the SO_2 BACT emission limits, at step one, EKPC identified the use of three potential types of coal for use as fuel in Unit 4 and examined the potential for controlling SO_2 emissions: high-sulfur western Kentucky

[11] EPA understands that permitting authorities have issued PSD permits for CFB boilers that contain SO_2 BACT emissions limits established by controlling the sulfur content of coal fuel used at the facility. *See, e.g., AES Puerto Rico*, 8 E.A.D. 324, ____ (near n3) (EAB 1999) (upholding issuance of a PSD permit for a CBF boiler that contained BACT limits on SO_2 emissions achieved through "a combination of three control strategies: 1) CFB boilers with limestone injection, 2) low sulfur coal (maximum sulfur content of 1.0%), and 3) an add-on dry scrubber").

coal (DB coal), PRB coal, and low sulfur eastern bituminous coal.[12] Supplemental BACT Analysis for Spurlock Unit 4 (January 12, 2006) at 6-7. From the analysis, it does not appear that EKPC eliminated any of these three coal options as technically infeasible at Step two. *See id.*

In accordance with Step three of the BACT analysis, EKPC provided information regarding the SO_2 potential for the each of three coal types: 0.8 for PRB coal, 1.23 for low sulfur eastern bituminous coal, and 9 for DB coal. *Id.* at 7. In Step four, EKPC provided an economic analysis of the SO_2 control achieved with each coal, including total, average, and incremental costs. In examining the control costs of the various coals considered, EKPC's analysis provides the following:

	Total Coal Cost (approx. $)	Difference in Cost (approx. $)	Average Control Cost ($/ton SO_2 removed)	Incremental Control Cost ($/ton SO_2 removed)
Design (DB) coal	30,662,842	baseline	283	baseline
PRB coal	76,650,000	45,987,158	8,033	23,733
Low sulfur E. Bit. coal	45,715,846	15,053,003	3,092	7,898

Supplemental BACT Analysis at 7-8.[13] *See also Inter-Power of New York*, 5 E.A.D. at 135 (explaining that BACT economic analysis usually involves an evaluation of two costs – "the total cost per ton of control for the pollutant" and "the comparative cost-effectiveness of various control options to determine their incremental cost-effectiveness"). In other words, EKPC determined that using PRB coal instead of DB coal would increase total fuel costs by approximately $46 million and would cost $23,733 more per ton of additional SO_2 control. EKPC then

[12] EKPC's analysis also includes relevant information for washed DB coal, but as will be explained in § 7c *infra*, coal washing is considered to be a supplemental SO_2 control option considered after, and in addition to, the selection of primary SO_2 controls, such as coal to be used in the boiler. Accordingly, EPA's review of the SO_2 BACT analysis with regard to coal choice is limited to these three different types of coal and excludes washed DB coal.

[13] EKPC has provided somewhat different cost figures in its response to the Title V petition. *See* Response to title V Petition at page 19. Since the response does not provide any information regarding the basis of the new figures and KDAQ's Supplemental BACT Analysis was before KDAQ when it issued the permit, EPA's review will focus on the information provided in KDAQ's Supplemental BACT Analysis.

eliminated PRB coal as "not economically viable" given total costs. Supplemental BACT Analysis at 7. After examining incremental costs, EKPC determined that the design basis coal was "the most economical for Unit 4," and based on this assessment, EKPC then selected the design basis coal as BACT for SO_2 emissions. *Id.* at 8.

However, EKPC's BACT selection in this instance is deficient because the analysis does not demonstrate that use of low sulfur eastern bituminous coal is not achievable for this source considering technical feasibility or economic, environmental, or energy impacts. *Indeck-Elwood*, slip op. at 77 (*citing Knauf Fiber Glass*, 8 E.A.D. 121, 130 (EAB 1999). Since EKPC's analysis shows that low sulfur eastern bituminous coal has a lower SO_2 potential than the DB coal (1.23 compared with 9), EKPC must provide a basis for excluding that option as a BACT and selecting a less stringent emission limit associated with the DB coal. EKPC's Supplemental BACT analysis does not sufficiently address the economic, environmental, or energy impacts of using low sulfur eastern bituminous coal. *See id.* at 7-8. While EKPC determined that the design coal was "the most economical", this does not demonstrate that use of low sulfur eastern bituminous coal is economically infeasible for this source. *See, e.g., Masonite Corp.*, 5 E.A.D. 551, 564 (EAB 1994) (Determining whether use of a technology is cost effective usually involves a comparison of the control option's cost-effectiveness "with what other companies in the same industry have been required to pay in recent BACT determinations to remove a ton of the same pollutant. In most cases, a control option is determined to be economically achievable if its cost-effectiveness is within the range of costs being borne by other sources of the same type to control the pollutant.") (citing *Inter-Power of New York*, 5 E.A.D. at 135).

Accordingly, the Administrator is granting this petition with respect to the issue of low sulfur coal and remanding the permit to KYDAQ and EKPC for further explanation and/or analysis regarding the choice of the design basis coal as BACT for SO_2 and, if necessary after such analysis, for adjustment of the SO_2 limit to appropriately reflect BACT. *See Indeck-Elwood*, slip op at 83 (remanding a specific BACT determination to the permitting authority after finding the record did not provide a sufficient explanation for the decision making process used to set the emission limit). In so doing, EPA is not concluding that the Unit 4 permit's SO_2 limit does not represent BACT – only that the present permit record does not provide EPA (or the public) sufficient information to make a reasonable decision as to the adequacy of the BACT determination.

2. Sulfur Oxide (SO_2) BACT Limit and Coal Washing

<u>Petitioner's Comment</u>: Petitioner claims that the SO_2 emission limit for Unit 4 is too high because the BACT determination failed to consider coal washing as a method to reduce SO_2 emissions. KYDAQ did not provide an adequate basis for concluding that coal washing was not an effective SO_2 reduction technique. The

permit also fails to recognize that coal washing must be considered for all coal types in the BACT determination, not just for the EKPC's preferred source of coal.

EPA's Response: Contrary to Petitioner's assertions, KYDAQ and EKPC did consider the feasibility of coal washing as a way to limit SO_2 emissions from this project. *See generally* EKPC Supplemental BACT Analysis at 8-9 and related tables at 7, 8; KYDAQ's Response to Comments at 54-56. KYDAQ determined that washed DB coal was not BACT because "coal washing is not uniformly effective in reducing sulfur in [the design basis] coal." KYDAQ's Response to Comments at 56. Such a determination is consistent with the EAB's determination that "a permitting authority must be allowed a certain degree of discretion to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently." *Masonite Corporation* at 551 and 560-561.

While Petitioner argues that KYDAQ's only support for its determination is a website, Petitioner does not provide any information showing that coal washing is a consistently effective mechanism for reducing sulfur in eastern coal or provide information showing that KYDAQ's analysis "was so flawed as to be clearly erroneous." *Inter-Power of New York*, 5 E.A.D. at 146. Moreover, in addition to the website, KYDAQ also based its coal washing determination on EKPC's BACT analysis. *See* Permit Statement of Basis at 22 (noting that all BACT determination relied, in part, on EKPC's BACT analysis). EKPC's analysis excluded coal washing as an effective add-on BACT mechanism based on adverse economic, environmental, and energy impacts. See Supplemental BACT Analysis at 8-9 (noting that coal washing cost $11,706 per ton SO_2 removed, would produce slurry ponds, and would lower pollutant removal efficiencies in the CFB). Thus, based on the information provided by KYDAQ and EKPC and the lack of information to the contrary from Petitioner, EPA does not find that the decision to exclude coal washing as an additional control mechanism for limiting SO_2 emissions brings this permit out of compliance with the CAA, including the PSD permitting requirements. *See Prairie State Generating Co.*, slip op. at 53-55 (finding that petitioners had failed to demonstrate clear error in the decision to reject coal washing in the BACT analysis when the analysis showed that any benefits of coal washing where outweighed by its cost, energy, and environmental impacts).

Petitioner's assertion that KYDAQ and EKPC were required to consider the feasibility of coal washing for all three coal types considered, and not just the design basis coal, is also misplaced. Having already determined earlier in the SO_2 BACT analysis that the other coal types could be excluded, KYDAQ and EKPC proceeded to determine whether the additional mechanism of coal washing could be combined with the remaining BACT option – the design basis coal – to further reduce SO_2 emissions.[14] *See Prairie State Generating Co.*, slip op. at 51-52

[14] While EPA acknowledges that the BACT determination with regard to coal selection is being remanded to KYDAQ as discussed above, this does not change the basic premise that coal washing is a supplemental control technology that can be considered after

(explaining why coal washing is an "additional" or "supplemental" control technology). Nothing in the PSD permitting requirements require that the possible emission reduction benefits of supplemental control technologies must be analyzed with regard to control options that have already been eliminated. Accordingly, Petitioner fails to demonstrate that the SO_2 limit contained in the permit for Unit 4 is not in compliance with the CAA. For these reasons, EPA denies the petition with respect to this issue.

3. Consideration of Integrated Gasification Combined Cycle (IGCC)

Petitioner's Comment: Petitioner argues that "[t]he Administrator must object to the permit because it contains limits that do not represent BACT," and explains that "[a] BACT analysis for a coal fired power plant must include consideration of Integrated Gasification Combined Cycle ("IGCC") technology." Petitioner emphasizes that "IGCC constitutes a cleaner production process and an innovative fuel combustion technique under the definition of BACT," and that "IGCC is a different process and combustion technique, which achieves much lower emission rates than the [circulating fluidized bed] process proposed for Spurlock 4." Petitioner argues that IGCC should be considered under the BACT analysis, and should not be considered to redefine the source, based on the definition of BACT under CAA section 169(3), the legislative history of that provision, and decisions of EPA's Environmental Appeals Board ("EAB" or "Board").

EPA's Response: EPA disagrees with Petitioner's conclusion. Petitioner has not sufficiently demonstrated to the Administrator that the permit limits, by not reflecting IGCC, do not represent BACT. As a result, Petitioner has not demonstrated that the permit fails to include applicable PSD requirements, and the petition is, therefore, denied with respect to this issue.

Petitioner made the same IGCC comment on the proposed permit as it now makes this petition. KYDAQ responded to the initial comment by stating: "IGCC would result in a redefinition of the basic design of the project and is not required under a BACT analysis ...." KYDAQ's Response to Comments at 44. [15]

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selection of the primary BACT fuel. Accordingly, the Administrator notes that if KYDAQ were to choose a different coal type as BACT following remand, KYDAQ should consider in its BACT analysis whether washing the different coal should be an additional SO_2 control technology for Spurlock Unit 4.

[15] KYDAQ added that "review of IGCC could be performed under [CAA] section 165(a)(2)," which requires the permitting authority to provide an opportunity for interested persons to comment on "alternatives" to the source. KYDAQ determined that "the Division will not require the use of an IGCC design as an alternative to a [circulating fluidized bed] unit," KYDAQ's Response to Comments at 44. Petitioners have not challenged the adequacy of this latter determination; and in denying this petition with respect to the IGCC issue, I am not making any determination regarding the adequacy of

In repeating, in their petition, the comments made on the proposed permit, Petitioners have not demonstrated that KYDAQ erred in declining to analyze IGCC under BACT on grounds that IGCC would redefine the source. The Administrator and the EAB have long maintained a policy against utilizing the BACT requirement as a means to fundamentally redefine the basic design or scope of a proposed project. *See e.g., In re Knauf Fiber Glass*, 8 E.A.D. 121, 140 (EAD 1998); *In the Matter of: Pennsauken County, New Jersey, Resource Recovery Facility*, 2 E.A.D. 667, 673 (Adm'r 1988) (*"Pennsauken County")*. EPA has not required applicants proposing to construct coal-fired steam electric generating facilities to evaluate building natural gas-fired combustion turbines as part of a BACT analysis, even though a gas turbine may be inherently less polluting. *In re SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *In the Matter of: Old Dominion Electric Cooperative Clover, Virginia*, 3 E.A.D. 779, 793 n. 38 (Adm'r 1992). Likewise, in *In re Hawaii Commercial & Sugar Co.,* the EAB found no error by the permitting authority in rejecting the petitioner's argument that the BACT analysis for a coal-fired steam electric generator should include the option of constructing an oil-fired combustion turbine. 4 E.A.D. 95, 99-100 (EAB 1992).

EPA's policy reflects the Agency's longstanding judgment that limits should exist on the degree to which permitting authorities can dictate the design and scope of a proposed facility through the BACT analysis. This policy is based on a reasonable interpretation of sections 165 and 169(3) of the CAA, which the EAB recently reiterated and explained in *In re Prairie State Generating Company*, PSD Appeal No. 05-05 (Aug. 24, 2006). In the *Prairie State* case, involving a permit for an coal-fired electric generating station that was co-located and co-permitted with a new coal mine supplying fuel for the facility, the Board determined that it was consistent with EPA's historic policy and the CAA for the permitting authority in this case to decline to conduct a detailed BACT review of the option of using lower-sulfur coal from another location. Based on various provisions of the CAA, including language that requires the "proposed facility" to be "subject to" BACT, the Board concluded that "the statute contemplates that the permit issuer looks to how the permit applicant defines the proposed facility's purpose or basic design" as part of Step 1 of the top-down BACT analysis. *Prairie State*, slip op. at 28-29. The Board further explained that "the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility." *Prairie State*, slip op. at 30. The Seventh Circuit recently affirmed the EAB's *Prairie State* decision, including the Board's interpretation of the interplay between determining what redefines a source and the required BACT analysis. *See generally Sierra Club v. EPA*, slip op. (7th Cir. Aug. 24, 2007).

As discussed by the Board in the *Prairie State* opinion, affirmed by the Seventh Circuit, and explained more fully below, EPA's policy against redefining

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KYDAQ's alternatives analysis. *Cf. Sierra Club v. EPA*, slip op. at 3 (7th Cir. Aug. 24, 2007) (finding that only the BACT requirements were at issue because the petitioners had not invoked the alternatives provision).

the proposed source through the BACT analysis is supported by a permissible and reasonable interpretation of the Clean Air Act. The language in sections 165 and 169 of the CAA distinguishes between the consideration of alternatives to a proposed source on the one hand, and permitting and selection of BACT for the proposed source on the other. Alternatives to a proposed source are evaluated through the CAA section 165(a)(2) public hearing process, which requires that, before a permitting authority may issue a permit, interested persons have an opportunity to "submit written or oral presentations on the air quality impact of such source, *alternatives thereto*, control technology requirements, and other appropriate considerations." 42 U.S.C. § 7475(a)(2) (emphasis added). By listing "alternatives" and "control technology requirements" separately in section 165(a)(2), Congress distinguished "alternatives" to the proposed source that would wholly replace the proposed facility with a different type of facility, from the kinds of "production processes and available methods, systems and techniques" that are potentially applicable to a particular type of facility and should be considered in the BACT review. *See* 42 U.S.C. § 7479(3).[16]

In contrast to the requirements of section 165(a)(2), other parts of the PSD permitting process, including the requirement to apply BACT, focus on, and are generally confined by, the project as proposed by the applicant. Sections 165(a)(1) and 165(a)(4) of the CAA provide that no facility may be constructed unless "a permit has been issued for *such proposed facility* in accordance with this part" and "the *proposed facility* is *subject to* best available control technology for each pollutant subject to regulation under the Act." 42 U.S.C. § 7475(a)(1) and (a)(4) (emphasis added). The following definition of BACT in section 169(3) of the Act also makes clear that the BACT review is based on the proposed project, as opposed to something fundamentally different:

> 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, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant.

42 U.S.C. § 7479(3) (emphasis added). The phrases "proposed facility" and "such facility" in section 165(a)(4) and 169(3) refer to the specific facility proposed by the applicant, which has certain inherent design characteristics. The Act also requires BACT to be determined "on a case-by-case basis." The case-specific nature of the BACT analysis indicates that the particular characteristics of each facility are an important aspect of the BACT determination. Thus, the Act requires

[16] As noted above, KYDAQ considered, but rejected, IGCC as an "alternative[]," and Petitioner has not challenged that determination.

that permitting authorities determine BACT for each facility individually, considering the unique characteristics and design of each facility.

However, as the Petitioner has pointed out, the statutory definition of BACT also requires permitting authorities in selecting BACT to consider "application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques." 42 U.S.C. § 7479(3). EPA has interpreted this phrase to require that permitting authorities evaluate both add-on pollution control technologies and lower polluting process in the BACT review. *Prairie State* at 33.

Considering these provisions together, the Act requires that the permitting authority conduct the BACT analysis on a "case-by-case" basis on the "proposed facility" while concurrently considering the "application of production processes and available methods, systems and techniques" that could alter the proposed facility. The statute does not provide clear direction on how the permitting authority is to reconcile these concepts and simultaneously consider the particulars of the facility proposed by the applicant while also assessing the use of methods or technology that could modify those particulars. Where a statute is ambiguous and Congress has not spoken to the precise issue, an administrative agency may formulate a policy to resolve the issue, provided that the policy is based on a permissible construction of the statute. *Chevron v. Natural Resources Defense Council*, 104 S.Ct. 2778, 2782 (1984). In this instance, sections 165 and 169(3) of the CAA are permissibly construed to authorize EPA and permitting authorities to establish some level of balance between the case-by-case nature of a BACT determination and the need to consider available processes, methods, systems, and techniques to reduce emissions. EPA's policy against redefining a source as part of the BACT analysis, which KYDAQ implemented for this permit, reasonably harmonizes the competing BACT obligations by requiring the permitting authority to consider potentially applicable processes, methods, systems, or techniques that may reduce pollution from the type of source proposed, provided such processes or techniques do not fundamentally redefine the basic design or scope of the facility proposed by the permit applicant.

EPA does not read the legislative history cited by the Petitioner to require a detailed evaluation of the IGCC technology in the BACT analysis for every proposed facility that generates electricity from coal. Petitioner points out that when Congress enacted the BACT definition in 1977, Senator Huddleston intended for the phrase "innovative fuel combustion techniques" to encompass "gasification" or "low Btu gasification,"[17] but this does not necessarily require EPA or other permitting authorities to identify the IGCC option as a candidate for further analysis at Step 1 of a top-down BACT review. The "innovative fuel combustion techniques" phrase appears in the BACT definition among a list of examples of things included in the phrase "production processes and available methods, systems, and techniques." Thus, the "innovative fuel combustion" language, like the phrase

[17] 123 Cong. Rec. S9434-35 (June 10, 1977) (debate on P.L. 95-95).

it modifies in the definition of BACT, is limited by other language discussed above that requires BACT to be applied to each proposed facility and determined on a case-by-case basis. Thus, even assuming that coal gasification was in all respects an innovative fuel combustion technique for producing electricity from coal, EPA does not interpret the CAA to require an "innovative fuel combustion technique" to be subject to a detailed BACT review when application of such a technique would re-design the proposed source to the point that it becomes an alternative type of facility, which, as discussed below, EPA believes would be the case if the IGCC technology were applied to Spurlock's Unit 4.

Furthermore, it is not clear from the terms of his statement that Senator Huddleston himself intended to require mandatory review of coal gasification in every case where such an option was not proposed by the permit applicant. Senator Huddleston said the purpose of the amendment was to leave no doubt that "all actions taken by the fuel user are to be taken into account." This phrase suggests the Senator wanted to make sure that, when a fuel user was proposing an innovative fuel combustion technique, such as coal gasification, that such actions by the fuel user would be taken into account and credited in the determination of BACT for the proposed facility. Thus, the Senator's statement could be read to express an intent similar to that expressed in a subsequent Congress when adding the phrase "clean fuels" to the definition of BACT in the 1990 amendments of the Clean Air Act. Pub. Law No. 101-549, § 403(d), 104 Stat. at 2631 (1990). At the time "clean fuels" was added to the list that includes "innovative fuel combustion techniques," the relevant Senate committee report stated the following in consecutive paragraphs:

> The Administrator may consider the use of clean fuels to meet BACT requirements if a permit applicant proposes to meet such requirements using clean fuel .... In no case is the Administrator compelled to require mandatory use of clean fuels by a permit applicant.

S. Rep. 101-228, at 338 (describing section 402(d) of S. 1630). Based on this legislative history, EPA does not interpret the list of examples that appear in the BACT definition after the phrase "production processes, methods, systems, or techniques" to require mandatory evaluation of each of those options at advanced stages of the BACT analysis, regardless of the degree to which such an option would redefine the type of facility proposed by the permit applicant.

Although EPA reads the Act to preclude redefining the source, EPA does not interpret the CAA to obligate a PSD permitting authority to accept all elements of a proposed project when determining BACT. To the contrary, EPA recognizes that the Act calls for an evaluation of the "application of production processes and available methods, systems, and techniques." 42 U.S.C. § 7479(3).

As the Board observed in *Prairie State*, EPA's policy against redefining the source is only relevant when considering lower polluting processes and would not permit a reviewing authority to rule out "add-on controls" at Step 1 of the BACT analysis. Slip op. at 33. Further, although EPA does not require a source to consider a totally different design, some design changes to the proposed source are within the scope of the BACT review. *See Knauf Fiber Glass,* 8 E.A.D. 121, 136. As the Board observed in the *Prairie State* case, the central issue in situations involving a lower polluting process concerns "the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not." Slip Op at 26. The Board observed that one of the permit issuer's tasks at Step 1 of the BACT analysis is to "discern which design elements are inherent to [the applicant's] purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility." *Prairie State*, slip op. at 30.

Since this line can be difficult to draw in each case, the Administrator and Environmental Appeals Board have generally recognized that the decision on whether to include a lower polluting process in the list of potentially-applicable control options compiled at Step 1 of the top-down BACT analysis is a matter within the discretion of the PSD permitting authority. *Knauf,* 8 E.A.D. at 136; *Old Dominion*, 3 E.A.D. at 793; *Hawaiian Commercial*, 4 E.A.D. at 100 and n.9. The Administrator and the EAB have usually respected the decisions of the permitting authority and only remanded permits in cases where it was clear that the permitting authority abused its discretion by excluding a particular option from consideration in the BACT review. *Knauf Fiber Glass,* 8 E.A.D. 121, 140; *See e.g., In the Matter of: Hibbing Taconite Company*, 2 E.A.D. 838, 843 (Adm'r 1989) ("*Hibbing*"). The Seventh Circuit affirmed this view in upholding the EAB's *Prairie State* decision, emphasizing the discretion given the permitting authority in making the technical judgment as to "where control technology ends and a redesign of the 'proposed facility' begins." *Sierra Club v. EPA,* slip op. at 5.

Petitioners insist that in *Pennsauken County,* the EAB made clear that the "'redefining the source' policy only prevents substituting a type of industrial category for another," and does not prevent substituting one type of source for another type of source in the same source category. Petitioners argue that the EAB affirmed this view in *Hibbing.* EPA does not read those two decisions in that manner. In particular, in *Hibbing*, the Board considered whether the option in question would "require any fundamental change to Hibbing's product, purpose, or equipment." Hibbing at 843 n. 12. Thus, in *Hibbing,* the EAB specifically identified a "fundamental change to ... equipment" as a type of redefinition of the source.

With respect to the project proposed by Spurlock, Petitioner's have not demonstrated that the KYDAQ erred in concluding that the application of the IGCC process to the facility would fundamentally change the nature of the proposed major source because it would fundamentally change the basic design of the equipment that EKPC proposes to install at Spurlock. Specifically, EKPC has proposed a facility that fires coal in a fluidized mixture with limestone and inert materials, in a boiler to generate steam to drive an electric turbine. An IGCC facility uses a chemical process to first convert coal into a synthetic gas and to fire that gas in a combined cycle turbine. "Final Report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," EPA-430/R-06/006, July 2006. The combined cycle generation power block of an IGCC process employs the same turbine and heat recovery technology that is used to generate electricity with natural gas at other electric generation facilities. Thus, this portion of the IGCC process is very similar to existing power generation designs that EPA has agreed would redefine the basic design of the source when an applicant proposed to construct a pulverized coal-fired boiler. *In re SEI Birchwood Inc*, 5 E.A.D. 25 (1994); *Old Dominion Electric Cooperative Clover,* 3 E.A.D. 779. Furthermore, the core process of gasification at an IGCC facility is fundamentally different than a boiler. Coal gasification is more akin to technology employed in the refinery and chemical manufacturing industries than technologies generally in use in power generation (i.e. a controlled chemical reaction versus a true combustion process). Use of coal gasification technology would necessitate different types of expertise on the part of the applicant and employees to produce the desired product (electricity). Thus, these fundamental differences in equipment design are sufficient to conclude that the IGCC process would redefine the proposed source.

EPA acknowledges that in the *Prairie State* case, the EAB recognized that IGCC technology could be listed as a potentially applicable option at Step 1 of the BACT analysis, as Illinois EPA had elected to do in that case. However, the Board's opinion in *Prairie State* did not interpret the CAA to require IGCC to be listed as a potentially applicable control option at Step 1 for every permit application involving a coal-fired steam electric generating unit. That is, the Board did not conclude that IGCC, or any other option involving such extensive design changes, had to be listed as a potentially applicable option at Step 1 in each case or find that it would be an abuse of a permitting authority's discretion to decline to list IGCC at Step 1 of the BACT analysis for the type of facility proposed by Spurlock. The Board continued to recognize that the decision of where to draw the line between BACT options listed at Step 1 and alternatives to the proposed source is ultimately a matter within the discretion of the permitting authority. *Prairie State* slip op. at 29 n. 22.

Accordingly, I believe that the KYDAQ properly exercised its discretion in determining not to consider IGCC in the BACT analysis for Spurlock Unit 4, and Petitioner has not demonstrated that the title V permit fails to contain applicable requirements as a result. Accordingly, I deny the petition with respect to this issue.

4. Visible Emission Standard

Petitioner's Comment: The definition of BACT contained in the Kentucky SIP requires that a visible emission standard be included in each BACT limit for pollutants constituting visible emissions (i.e. PM/PM_{10} and SAM). Although a BACT limit for PM, PM_{10} or SAM typically includes an emissions rate limit, the Kentucky SIP requires BACT limits to include a visible emission standard.

EPA Response: In responding to Petitioner's claim concerning opacity for Unit 3, EPA expressed that BACT does not require an opacity limit. *See discussion* Section E.1., *supra*. Pursuant to 401 KAR 51:001(25), BACT is defined as "an emissions limitation, including a visible emission, based on the maximum degree of reduction for each regulated NSR pollutant that will be emitted from a proposed major stationary source or major modification that ...." Petitioner asserts that the phrase "including a visible emission standard" requires a visible emission standard in each BACT limit for pollutants constituting visible emissions. Based on EPA's interpretation of similar regulatory language contained in 40 C.F.R. § 52.21(b)(12), it was reasonable for KDAQ to conclude that visible emissions may be part of a BACT emissions limit but are not a required element of BACT. This position is consistent with KYDAQ's Response to Comments at page 46, which states in part ... "opacity may be an indicator of particulate matter, fumes, gases or vapor, but is not an independent entity to be regulated. Opacity is the property for the absorption of light, an appropriate indicator for a variety of air pollution concerns, but not a regulated NSR pollutant."[18] Notwithstanding Petitioner's claim, the permit does contain an opacity limit of 20 percent. Further, PM/PM_{10} will also be monitored by PM CEMS which will provide a continuous method for ensuring compliance with the particulate emissions standard. For these stated reasons, EPA denies the petition with respect to this issue.

5. BACT Limit for Fine Particulate Matter ($PM_{2.5}$)

Petitioner's Comment: The permit must include a BACT limit for $PM_{2.5}$ emissions from Unit 4 because $PM_{2.5}$ is a regulated NSR pollutant. Further, EPA established a "national ambient air quality standard" (NAAQS) for $PM_{2.5}$, and the Kentucky SIP requires a BACT limit "for each regulated NSR pollutant for which the source has the potential to emit in significant amounts." 401 KAR 51:017.

EPA's Response: While EPA acknowledges that $PM_{2.5}$ is a regulated NSR pollutant, at this time EPA has not yet implemented NSR regulations for $PM_{2.5}$ NAAQS. It is well established that EPA has proposed the interim use of PM_{10} as a

[18] *See also* Illinois Environmental Protection Agency Bureau of Air, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application from Springfield City Water, Light and Power for Proposed Dallman Unit 4 at 39 (stating that "since opacity is not a pollutant, there is not a statutory obligation to set an opacity limit").

surrogate for $PM_{2.5}$ until NSR rules have been implemented. EPA has represented that:

> In view of the significant technical difficulties that now exist with respect to $PM_{2.5}$ monitoring, emissions, estimation, and modeling, EPA believes that PM_{10} may properly be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.
>
> When the technical difficulties are resolved, EPA will amend the PSD regulations under 40 C.F.R. §§ 51.166 and 52.21 to establish a $PM_{2.5}$ significant emissions rate and EPA will also promulgate other appropriate regulatory measures pertinent to $PM_{2.5}$, and its precursors.

Memorandum from John Seitz, Office of Air Quality Planning and Standards, "Interim Implementation of New Source Review Requirements for $PM_{2.5}$" (October 21, 1997).

This position was recently reaffirmed in specific guidance to the states:

> Using the surrogate $PM_{2.5}$ nonattainment major NSR program, States should assume that a major stationary source's PM_{10} emissions represent $PM_{2.5}$ emissions and regulate these emissions using either Appendix S or the States' SIP-approved nonattainment major NSR program.[19]

Memorandum from Stephen Page, Office of Air Quality and Planning and Standards (April 5, 2005). Thus, under the circumstanees presented here, it was clearly appropriate for KYDAQ to use PM_{10} as a surrogate for $PM_{2.5}$. For these reasons, EPA denies the petition with respect to this issue.

6. PM Emissions from Unit 4 Cooling Tower

Petitioner's Comment: The source was required to consider as BACT for PM the use of a less polluting process, i.e., an air cooled condenser (ACC). KYDAQ unlawfully restricted its BACT analysis to the cooling design proposed by the facility.

[19] The terms of 40 C.F.R. § 52.24(k), Appendix S of Part 51 provide provisions for a transitional nonattainment major NSR program until EPA approves a State's Part D major NSR program into the SIP.

EPA's Response: EPA concurs with the position taken by KYDAQ regarding the appropriateness of the selected BACT for PM emissions from the cooling tower for Unit 4. In responding to the Petitioner, KYDAQ stated:

> Given that EKPC has chosen to build a facility employing a cooling tower as part of the process, a drift eliminator with a maximum drift rate of 0.0005 percent as included in the permit is BACT.

KYDAQ's Response to Comments at 49.

Petitioner asserts that the use of an ACC would be more appropriate because it is a less polluting process. However, Petitioner has failed to demonstrate that ACC technology is feasible at this source. BACT as defined by the CAA and Kentucky regulations allow for the use of a design standard rather than an emissions standard when technological limitations make imposition of an emission standard infeasible. As previously discussed, this interpretation has been confirmed by the Supreme Court and in numerous EAB decisions that took into consideration geographical differences and other constraints in determining that a given technology was not feasible for a particular source. *See Alaska Dept. of Environmental Conservation*, 540 U.S. 461, 488 (2004); *In re Cardinal FG, Co.*, PSD Appeal No. 04-04 slip op. at 11; and *In re Three Mountain Power*, 10 EAD 39 (EAB 2001). Such considerations are appropriate here, because the ACC technology advocated by the Petitioner is typically utilized in drier climate, particularly where the water supply is limited. In more humid climates, the technology is less effective and not as economically viable where water is less expensive. For these reasons, ACC is typically not considered a feasible technology for sources located in the southeast region of the United States, such as the Spurlock Station. *See Masonite Corp*, 5 EAD at 560 (noting that the permit issuer must have flexibility where "the technology itself or its application to the type of facility in question may be relatively unproven").

EPA previously determined that ACC was not the best technology available in its Clean Water Act § 316(b) rulemaking. 66 Fed. Reg. 65256, 65282 (Dec. 18, 2001). EPA estimated that the energy penalty of an ACC plant in a hot environment at peak summer conditions could be as much as 19.4 percent. Further, the cost of ACC is more than three times the cost of wet cooling after considering the costs for construction and operating costs. In light of the foregoing information, it is EPA's position that KYDAQ's BACT determination is reasonable for PM emissions from the cooling tower for Unit 4. For these reasons, EPA denies the petition with respect to this issue.

7. Monitoring and Reporting of PM Emissions from the Cooling Tower

Petitioner's Comments: Utilizing 0.0005 percent drift eliminators is not BACT for PM and it is not an enforceable emission limit. The permit must contain a BACT limit for PM/PM_{10}. PM/PM_{10} emissions result when drift from a cooling tower evaporates and leaves mineral and other solids as suspended particulate matter in the air. An effective BACT limit must regulate all these factors or directly limit PM/PM_{10}. The permit does not require a correlation between these factors and PM/PM_{10}. Additionally, the permit requires only a one-time drift rate test rather than periodic tests. This is not sufficient to demonstrate continuous compliance with applicable limits.

EPA's Response: Contrary to Petitioner's assertion, the drift elimination rate limit of 0.0005 percent as BACT for the Unit 4 cooling tower is consistent with BACT determinations in several other recent coal-fired power plant permits. Recent examples of permits for coal-fired power plants with similar BACT limits for cooling towers include Longleaf Energy pulverized coal project in Georgia (0.001 percent); the Longview Energy pulverized coal project in West Virginia (0.002 percent); and the Prairie State Generation pulverized coal project in Illinois (0.0005 percent).

Further, Petitioner claims that the Spurlock permit provides insufficient monitoring provisions for emissions from the cooling tower is unsubstantiated. Specifically, the permit requires monthly monitoring of total dissolved solids (TDS) content of the circulating water and requires maintenance of records of the maximum pumping capacity and TDS content. Permit, Emissions Unit 23, Sections B.4 and 5. In addition, the permit requires the source to perform an initial performance test to assess the efficiency of the drift eliminators, as well as maintain the drift eliminators in accordance with the manufacturer's specifications. In making its claims, Petitioner provides no information to support the idea that the permit contains deficient monitoring for PM/PM_{10} and that periodic drift tests should be required. EPA finds that the permit contains sufficient monitoring, recordkeeping and performance test requirements for enforceability of the requirement to install a 0.0005 percent drift eliminator as a method of limiting PM emissions.

Finally, Petitioner's recommendation that a limit be placed on mineral and other solids that are suspended as particulate matter in the drift from the cooling tower is highly impractical, since EKPC has no direct control over the dissolved solids concentration in the Unit 4 emissions. Given the low drift elimination rate limit of 0.0005 percent established as BACT for the Unit 4 cooling tower, EPA does not believe that additional limits for PM_{10} emissions are necessary or practical.[20] For these reasons, EPA denies the petition with respect to this issue.

8. BACT Limit for Mercury and Beryllium

Petitioner's Comment: The Kentucky SIP, existing at the time the permit was issued, requires BACT limits for facilities that emit mercury in a "significant" amount. Although the Kentucky administrative regulations have recently been

[20] In light of this conclusion, Petitioner has not demonstrated that any failure to respond to comments on this issue resulted in, or may have resulted in, a flaw in the permit.

changed with respect to the level of mercury and beryllium emissions considered significant, the change has not yet been approved by EPA. Therefore, the existing Kentucky SIP controls and a BACT limit for mercury and beryllium is required. Additionally, because mercury is subject to a new source performance standard, a BACT limit for mercury must be established.

EPA's Comment: EPA has since approved Kentucky's revised SIP that changes the amount of mercury emissions that are considered "significant." 71 Fed. Reg. 38,990 (July 11, 2006). Since the mercury level referenced by Petitioner is obsolete and no longer applicable to the level of emissions generated at the Spurlock Station, this issue is moot. *See Glynn Environmental Coalition, Inc. v. EPA*, Docket No. 05-10375-GG (11 Cir. 2006) (dismissing petition as moot where sole issue was whether permit contained sufficient conditions to assure compliance with a rule that had since been removed from the Georgia SIP).

Petitioner also asserts that a BACT limit for mercury is required by the CAA because it is it is a regulated NSR pollutant under 401 KAR 51:001, which includes pollutants that are subject to any standard promulgated under 42 U.S.C. § 7411. However, CAA § 112(b), 42 U.S.C. § 7412(b) specifies that "the provisions of Part C (Prevention of Significant Deterioration) shall not apply to pollutants listed under this section." Mercury and beryllium compounds are listed in Section 112(b)(1) of the CAA. The CAA provides a note to Section 112(b)(1) explaining that " for all listings above which contain the word 'compound' ... the following applies: Unless otherwise specified, these listings are defined as including any unique chemical substances that contains the named chemical ... as part of that chemical infrastructure." *See also* KYDAQ's Response to Comment at 73. Consequently, since both mercury and beryllium are listed HAPs regulated under Section 112, the PSD program requirements do not apply to these emissions. *See Newmont*, slip op. at 75-77 (concurring with Nevada Department of Environment that PSD provisions do not apply to mercury). For these reasons, EPA denies the petition with respect to this issue.

V. CONCLUSION

For the reasons set forth above, and pursuant to section 505(b)(2) of the Clean Air Act, I partially deny and partially grant the petition from the Sierra Club requesting that the Administrator object to the issuance of the title V permit for the Spurlock Station owned and operated by East Kentucky Power Cooperative, Inc.

Dated: AUG 30 2007

Stephen L. Johnson
Administrator

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February 1, 2008

VIA ELECTRONIC AND PRIORITY MAIL

James Morse
Division for Air Quality
803 Schenkel Lane
Frankfort, KY 40601

Re: Draft Revised Title V Permit V-06-007 Revision 2
East KY Power Cooperative, Inc.-H.L. Spurlock Power Station
Plant I.D. 21-161-00009

Mr. Morse:

These comments are submitted on behalf of the Sierra Club. The Division is proposing to revise the Title V permit for the Spurlock plant to increase the heat rate limit included in the prior state operating permit and to justify the Division's prior failure to consider clean fuel, low sulfur coal in the BACT analysis for SO2. Both proposals are in error for the reasons set forth below.

As an initial matter, the Division and State of Kentucky have forfeited jurisdiction over the final permit for the Spurlock plant. Following the U.S. EPA Administrator's objection on the Division's prior permit ("Administrator Order"), the Division was required to respond with a permit corrected to meet the Administrator's objections within 90 days. 42 U.S.C. § 7661d(c). The objection was dated August 30, 2007. Ninety days expired on November 28, 2007. The Division failed to submit a revised permit before that date. Neither EPA nor the Division has authority to extend that deadline, notwithstanding EPA's letter purporting to do so. Furthermore, to the extent that the current draft permit was provided to U.S. EPA, it fails to "meet the objection" of the Administrator because it fails to include a 4850 MMBtu/hour heat input limit for

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EXHIBIT C

Unit 2. 42 U.S.C. § 7661d(c). For each of these reasons, the Division no longer has authority to issue the permit and, instead, U.S. EPA is now the permitting authority.

By submitting these comments Sierra Club does not waive its objection to the Division continuing to assume jurisdiction over the permit. Sierra Club has provided a notice of its intent to sue the U.S. EPA, pursuant to 42 U.S.C. § 7604, to compel the EPA to issue the permits for the Spurlock plant.

I. THE DRAFT PERMIT DOES NOT MEET THE ADMINISTRATOR'S OBJECTION BECAUSE IT FAILS TO INCLUDE A 4850 MMBTU PER HOUR HEAT INPUT LIMIT FOR UNIT 2.

The basis of the Administrator's August 30, 2007, objection was that the Title V permit failed to include the 4850 MMBtu/hour heat input limit applicable to Unit 2. The Administrator fist pointed out that the failure of KDAQ to include the 4,850 MMBtu/hour limit from a 1983 state operating permit in a prior, 1999, Title V permit did not revoke the heat input limit. Administrator Order at 12. The Administrator further pointed out that a Title V permit cannot change applicable requirements in underlying permits. *Id.* Therefore, the Administrator found that the 1983 permit limit of 4850 MMBtu/hour remained as an applicable requirement. *Id.*

> Instead, the underlying permit in which the applicable requirement is found must be modified, and then incorporated into the Title V permit as an applicable requirement. Thus, the placement of the maximum heat input in the description section of EKPC's 1999 title V permit could not have eliminated the heat input limit as an applicable requirement of the underlying 1983 SOP.
>
> Based on the foregoing, EPA finds that the title V permit is deficient for its failure to include as an applicable requirement the maximum heat input limit found in the underlying 1983 SOP. Therefore, I grant the petition on this issue and direct KYDAQ to amend the permit and to include the applicable heat input limit for Unit 2 under the "Operating Limits" category of the permit.

Administrator Order at 12 (emphasis added). The "underlying SOP" contains a 4850 MMBtu/hr "maximum heat input" limit. See Kentucky Natural Resources and Environmental Protection Cabinet PERMIT, Re: H.L. Spurlock Power Station

(November 10, 1982) (Attached as Exhibit A). Therefore, to satisfy the Administrator's objection, this 4850 MMBtu/hour maximum heat input limit must be included. The draft permit's proposed 5900 MMBtu/hour limit does not satisfy the objection.

II. INCREASING THE HEAT INPUT LIMIT REQUIRES PSD PERMITTING, AS KDAQ PREVIOUSLY ACKNOWLEDGED.

In addition to failing to satisfy the objection of the Administrator, the draft permit's proposed 5900 MMBtu/hour limit is an unlawful modification to applicable Clean Air Act Title I standards through a Title V permit.

The 4850 MMBtu/hour operating limit is required by the PSD permit issued for the original construction of Unit 2. When EKPC applied for a permit to construct Unit 2 in January 1976, EKPC represented to U.S. EPA that EKPC would construct and operate a pulverized coal unit with a maximum heat input of 4850 million Btu/hour. See Letter from Ronald L. Rainson, EKPC, to G.T. Helms, U.S. EPA and attachments (March 19, 1976) (attached as Exhibit B hereto); Letter from William Gill, EKPC, to Frank L. Stanonis, Kentucky Bureau of Environmental Quality, and attachments (January 23, 1976) (attached as Exhibit C hereto). This representation of the 4850 MMBtu/hour maximum heat rate becomes an enforceable requirement because 40 C.F.R. § 52.21(r), which is applicable because the original PSD permit for Unit was issued by U.S. EPA pursuant to Part 52, requires that a PSD applicant construct and operate the source consistent with and according to the specifications provided in its permit application. Additionally, as is apparent from U.S. EPA's review and administrative findings in support of the PSD permit issued for Unit 2, U.S. EPA relied on the maximum 4850 MMBtu/hour heat input when determining air quality impacts and issuing the permit. See Letter from John A. Little, U.S. EPA to Robert Hughes, EKPC, attaching analysis and permit (September 21, 1976) (attached hereto as Exhibit D).

Additionally, a federally-enforceable state operating permit was issued by Kentucky that limits Unit 2 to 4850 MMBtu/hour. See November 10, 1982 Permit, supra (Exhibit A). For each of these reasons, the 4850 MMBtu/hour limit is an applicable requirement that can only be modified after satisfying all requirements of Clean Air Act Title I. EKPC has not applied for, nor been issued, a pre-construction permit for a heat rate change to Unit 2. Therefore, the Permit must include the existing operational limit of 4,850 million Btu/hour.

The Title V program does not and cannot impose nor change applicable requirements. As the Administrator's Order expressly states—where a state has a merged PSD and Title V program, as Kentucky does—changes to applicable heat rate requirements must be done "outside of the title V part of the process and the rationale for the change must be clearly stated." Administrator Order at 12 n.6. KDAQ cannot include in the revised permit any heat rate limit other than the 4850 MMBtu/hour limit from the original PSD permit and original Kentucky SIP-based operating permit. If EKPC wishes to increase the heat rate, it must undergo PSD permitting and satisfy all other Clean Air Act Title I requirements.

In fact, the KDAQ previously denied EKPC's request to increase the heat rate limit through a prior Title V permit unless EKPC goes through PSD permitting. In December, 1993, East Kentucky sought an increase in the permitted maximum hourly heath input for Unit 2 from 4850 to 5355 MMBtu/hour. Letter from Robert E. Hughes, Jr., EKPC, to John Hornback, KDAQ Re: H.L. Spurlock Power Station- Unit #2 BTU Heat Input (attached hereto as Exhibit E). In February, 1994, KDAQ responded by asserting that any such increase would be considered a major modification under the PSD rules and be subject to PSD permitting requirements if it resulted in a significant net emissions increase. Letter from Gerald R. Goebel, KDAQ, to Robert E. Hughes, Jr., EKPC Re: Request to increase permitted heat input for Unit 2 at the H.L. Spurlock Station (R7532) I.C. # 103-2640-0009 (February 3, 1994) (attached hereto as Exhibit F). Specifically, KDAQ stated that "the Permit Review Branch has determined that if the proposed increase in the heat input rate results in a significant net emissions increase, then your proposal would be a major modification, as defined in Regulation 401 KAR 51:017." *Id.* In January, 1995, EKPC conceded that the 4850 MMBtu/hour heat input cannot be changed without undergoing PSD permitting and rescinded its request for the heat rate increase. Letter from Robert E. Hughes, Jr., EKPC, to Gerald R. Goebel, KDAQ Re: Letter of December 20, 1994 Spurlock Unit 2 (January 16, 1995) (attached hereto as exhibit G).

If there were any doubt as to KDAQ's prior position that a change in the permitted heat rate required a PSD permit, KDAQ reaffirmed that it did in its response to comments on the original Title V permit for the plant. During the public comment process for the 1999 Title V permit, EKPC again requested that the maximum heat rate for Unit 2 be increased to 5600 MMBtu/hour. Response to East Kentucky Power's Comments (3/13/98 Letter) at 2 (attached hereto as Exhibit H). KDAQ again denied the request without PSD permitting, stating: "As stated in the Division for Air Quality letter dated February 3, 1994, this rating cannot be increased until the demonstration of applicability or non-applicability of Regulation 401 KAR 51:017, Prevention of significant deterioration of air quality." *Id.*

Despite the fact that Title V permits cannot change applicable requirements, and that KDAQ has previously denied EKPC's requests to modify the heat input limit without PSD permitting, KDAQ is currently proposing to do exactly that: to raise the heat rate from 4850 MMBtu/hour to 5900 MMBtu/hour through a Title V revision, and without going through PSD permitting. *See also* Administrator Order at 12 n.7 ("It is apparent that the EKPC was aware that the heat input limit was an enforceable limitation in that it previously requested that KYDAQ revise the maximum heath rate for Unit 2 from 4,850 million [sic] mmBtu/hr to 5,3555 [sic, 5,355] mmBtu/hr. KYDAQ denied EKPC's request when they informed EKPC that a PSD permit was required for such modification.").

KDAQ must include a 4850 MMBtu/hour limit in the permit. Should EKPC wish to increase this limit, it must apply for the appropriate permits under Clean Air Act Title I (including PSD).

III. USE OF CLEAN FUELS IS COST EFFECTIVE FOR SO_2 BACT

The Administrator's objection also concluded that EKPC and KYDAQ did not provide an adequate explanation for rejecting low sulfur coal as not economically viable. Administrator Order at 29-32. In response, the Statement of Basis ("SOB") for the revised permit calculates the cost of using low sulfur eastern bituminous coals as ranging from $9,317 to $25,665 per additional ton of SO_2 removed. SOB, p. 4. The SOB then compares this value with <u>incremental cost effectiveness</u> values for other similar projects without disclosing that they were relying on incremental cost effectiveness values. *Id.* Based on this comparison, the SOB concludes that "other permitting authorities have rejected additional sulfur removal costs above $5,000/ton as being excessive for BACT." *Id.* Therefore, the SOB concludes that additional sulfur removal using low sulfur coal is not economically feasible. *Id.*, pp. 4-5.

This analysis is premised on a number of conceptual errors and, as a result, arrived at an erroneous conclusion. As demonstrated below, the <u>average cost effectiveness</u> of removing additional SO_2 by using low sulfur coal is $155 to $427/ton, which is lower than the lower end of the range of average cost effectiveness values for similar sources relied on by KDEQ. Thus, low sulfur fuel is *per se* economically feasible.

A. Average And Incremental Cost Effectiveness Were Not Used

Average and incremental cost effectiveness are the two economic criteria that are used to determine if a control option is economically feasible in a BACT analysis. *NSR Manual*, Sec. IV.D.2. The Administrator's Order cited extensively to EAB cases supporting these two metrics defined as used in the *NSR Manual*. However, EKPC and KYDAQ responded with a single metric which is neither average nor incremental cost effectiveness.

The cost metric used in the SOB is variously called "cost comparison ($/ton)" and "cost of removal of an additional ton of SO_2." SOB pp. 3-4. This metric is neither average cost effectiveness nor incremental cost effectiveness and, in fact, has no basis in the practice of top-down BACT analyses. KDAQ's analysis compares the cost of fuel switching with the reductions achieved by a three-stage-control option using design coal: fuel switching, limestone addition to the CFB bed, and dry scrubbing. This is an erroneous and misleading comparison. The SOB also compares this unrecognized cost-effectiveness standard with incremental cost effectiveness values as specified in the Administrator's Order for a wholly different set of pollution controls.

The SOB calculates a single cost value, which purports to be incremental cost effectiveness, but upon close examination, is not. The SOB's cost metric is calculated as the ratio of the incremental fuel cost to the incremental amount of SO_2 emitted.

- First, the SOB calculates the difference in the annual cost to purchase the design fuel (9 lb SO_2/MMBtu and 10,757 Btu/lb) compared to the cost to purchase low sulfur fuel (1.2 lb SO_2/MMBtu and 12,500 Btu/lb) in dollars per year:

[Annual Cost of Design Coal – Annual Cost of Low S Coal] (1)

- Second, the SOB calculates the amount of SO_2 emitted when burning design fuel compared to the amount of SO_2 emitted when burning low sulfur coal in tons per year, assuming 99.33% SO_2 removal in both cases using limestone additions to the CFB bed and a dry scrubber:

[SO_2 Emitted Design Coal – SO_2 Emitted Low S Coal] (2)

- Finally, the SOB divides the incremental annual fuel cost by the incremental amount of SO_2 emitted and calls the results the cost per additional ton of SO2 emitted. As an example, the lower end of the SOB's cost range is calculated as:

[$44,582,093/yr - $29,730,565/yr]/[1840 ton/yr – 246 ton/yr] = ***$9,317/ton***

This result is neither average cost effectiveness nor incremental cost effectiveness, the metrics required by the Administrator's Order and the typical metrics used in PSD permitting. Further; the SOB's method of calculating cost are incorrect and substantially penalize low sulfur fuel by including SO2 emission reductions achieved by other control options and excluding the relative costs of these other controls.

This value is not average cost effectiveness because average cost effectiveness is the ratio of the control option annualized cost divided by the control option annual emission reduction. *NSR Manual* at B.36-B.37. This value is also not incremental cost effectiveness because incremental cost effectiveness is the ratio of the difference in annualized cost of two control options to the difference in the emission rates of these same two control options. *NSR Manual* at B.41. In both cases, cost effectiveness is the ratio of costs of a **control option(s)** to emission reductions achieved by that **control option(s)**. This is not what is calculated in the SOB.

Instead, the SOB calculates **control option** [low S coal] annualized cost divided by SO_2 emission reductions from the **entire control train** [low S coal + limestone bed + dry scrubber]. For incremental cost effectiveness, the annual emission reductions due to the use of low sulfur coal should be the difference between SO_2 in the design coal and SO_2 in the low sulfur coal or 95,659 ton/yr [110,376-14,717], not 1,594 ton/yr [1840-246]. The use of the lower value, after the post-combustion controls-- for emission reductions attributable to the lower sulfur coal artificially inflates cost effectiveness of low sulfur coal. KDAQ's analysis divides annual cost by incremental emission reductions, resulting in a calculated reduction that is 60 times smaller than it should be.

Correcting this error, incremental cost effectiveness of using a low sulfur coal ranges from $155/ton to $427/ton.[1] These values are below the lower end of the range of both average cost effectiveness ($527 to $4054/ton) and incremental cost effectiveness ($5,000-20,000/ton) relied upon by the SOB (which are also lower than other permitting authorities use).[2] Thus, the use of low sulfur coal is cost effective and cannot be eliminated based on cost effectiveness.

The use of emission reductions from the entire pollution control train to calculate cost effectiveness is also wrong because it includes reductions from adding limestone to the fluidized bed and dry scrubbing, but does not consider the relative costs of these additional controls when using design coal as compared to low sulfur coal. In other words, KDAQ's analysis attributes all of

[1] The lower end of the range from SOB, p. 4: ($14,851,528/yr)/(95,659 ton SO_2/yr) = $155/yr. The upper end of the range from SOB, p. 3: ($40,910,075/yr)/(95,659 ton SO_2/yr) = $427.67/ton.

[2] U.S. EPA Region 8, Response to Public Comments on Draft Air Pollution Control Prevention of Significant Deterioration (PSD) Permit to Construction, Deseret Power Electric Cooperative, August 30, 2007, pp. 29-33.

the reduction but none of the cost from limestone injection and scrubbing to the high sulfur coal when comparing the cost effectiveness of high and low sulfur coal. For the high-sulfur, "design coal," the limestone bed plus dry scrubber must reduce SO_2 emissions from 110,376 ton/yr to 1,840 ton/yr, or by **108,536 ton/yr**. For low sulfur coal, these controls need only reduce SO_2 from 14,717 ton/yr to 246 ton/yr or by **14,471 ton/yr**. SOB, p. 3. The cost to remove **108,536 ton/yr** of SO_2 with limestone injection and a scrubber when burning design fuel is substantially higher than the cost to remove only **14,471 ton/yr** when burning low sulfur coal. The economic benefit of controlling less SO2 with lower sulfur coal is not considered in the SOB.

The control costs for design fuel for the entire control train is higher than for low sulfur coal because a bigger, more efficient scrubber must be used; more limestone must be added to the fluidized bed; more water must be used to cool the flue gases; more solid wastes must be disposed; more electricity must be used to operate the scrubber; and more lime must be injected into the scrubber, among other increased costs incurred for the complete control trains as compared to just low sulfur coal. If the cost of these additional controls were included in both the cost of design coal and the low sulfur option, they would add substantially to the design coal costs and much less so to the low sulfur coal, thus narrowing the incremental cost. This would reduce incremental cost effectiveness. This is the reason that cost-effectiveness must look at the entire pollution control train—rather than attempting to add one piece (low sulfur coal) to a control train that is designed around a different input (high sulfur coal).

B. The Comparative Costs Are Not Representative

The SOB compares a metric it calls "cost comparison" or "dollars per additional ton of SO_2 removed" for using fuel switching to incremental cost effectiveness values for post combustion controls -- various types of dry scrubbers and sorbent injection. SOB, p. 4.[3] This is an apples-to-oranges comparison that creates a number of errors in KDAQ's analysis.

First, even assuming the SOB correctly calculated cost effectiveness (which it did not), the *NSR Manual* explains that "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if **any**, between the application of the control technology on those sources and the particular source under review." *NSR Manual* at 31 (emphasis added except as to "any"). In other words, the cost of controlling additional SO2 with low sulfur coal must be compared to the costs incurred by other plants that burn low sulfur coal. The

[3] The SOB does not disclose the control technology, but the source of the comparative cost data, EPA's response to comments in the Desert case, does disclose the controls.

NSR Manual elaborates that: "..if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT." *NSR Manual*, p. B.44 (emphasis added).

The comparison, then, must be on a "control technology" basis, not a pollutant basis. Neither EKPC nor KDAQ appear to have undertaken a comparison of the cost of fuel switching borne by other sources that have used fuel switching as a pollution control method with the cost of fuel switching in this instance at the Spurlock 4 unit. The record contains no comparative cost data for fuel switching as a control option. It is incorrect to compare the cost of scrubbing and sorbent injection, which are separate and distinguishable SO2 control technologies, to the cost of fuel switching.

Second, cost comparisons should be made on an "apples-to-apples" basis. E.g., *NSR Manual* at B.39 (stating that a source that compares costs between options must do so with standard assumptions for all options, discussing an 85% capacity factor in that case). The comparative cost data are based on incremental cost effectiveness, calculated as explained in the *NSR Manual* at p. B.41. These values compare the cost of a wet scrubber with the cost of a dry scrubber—a one to one comparison. However, the SOB then attempts to compare the fuel costs, alone, to the emission reductions based on low sulfur coal plus both a limestone CFB bed and a dry scrubber. This distorts the comparison and inflates the cost per ton calculation.

Further, the EPA cost data are not otherwise directly comparable as they are based on different assumptions as to capacity factor (Longleaf, for example, assumed 85%), SO_2 control efficiency (Cargil, for example, assumes only 75% SO_2 control efficiency for SDA while others assume 90%+), interest rate, and equipment life, factors that must be constant from plant to plant to be used in a comparative cost analysis. KDAQ's analysis fails to account for these differences.

C. KDAQ Failed to Use Range Of Comparative Cost Data

First, the SOB compared the cost value it calculated, $9,317/ton, with the lower end of the range of the reported comparative cost data. The incremental cost data summarized from EPA ranges from $5,000/ton to $23,855/ton. A control option is considered cost effective if it is "within the range of normal costs for that control alternative..." *NSR Manual* at B.31 (emphasis added). All of the cost values reported in the SOB, which range from $9,317/ton to $25,665/ton are well within the range of reported comparative cost data. The

SOB has provided no justification for focusing on a single determination by Pennsylvania for the River Hill CFB.

Second, the one determination relied on by KDAQ, River Hill, is based on an Application submitted in July 2004. Pollution control costs have escalated dramatically since then.[4] As a result, what is cost effective today may be greater, in unadjusted dollars, than what was considered cost effective four years ago. Moreover, the SOB cost calculations are based on 2006 dollars. By adjusting the 2004 River Hill cost data (based on scrubbers) to 2006 dollars-- using the Vatavuk cost index-- the \$5,000/ton value relied on by KDAQ becomes \$7,040/ton in 2006 dollars.[5] Adjusting to current dollars would result in a similar increase. Moreover, this ~\$7,000/ton value is within about 30% of the cost value proffered by KDAQ, \$9,317, and thus, even under KDAQ's limited use criterion, is cost effective. *NSR Manual* B.44 ("Study cost estimates used in BACT are typically accurate to +/- 20 to 30 percent. Therefore, control cost options which are within +/- 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options."). The cost of low sulfur coal at Spurlock 4 is certainly "on the same order" as the River Hill cost, when adjusted for inflation. *NSR Manual* B.44 ("if the cost...is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT.") Thus, low sulfur coal is cost effective <u>even under KDAQ's incorrect metric</u> for calculating the cost per ton.

Third, the next lowest value used for comparison suffers similar problems. Nebraska required the applicant to use lower sulfur coal than proposed, 2.7 lb SO_2/MMBtu compared to its proposal of 3.57 lb SO_2/MMBtu. In that case, lower sulfur coal was economic. Cargil Final Permit at pdf 32. The cost effectiveness value of \$5,900/ton corresponds to an additional reduction of only 75% above limestone injection using a dry scrubber, which is not representative of the instant case.

Fourth, none of the comparative cost data the SOB relies on used comparative cost data to determine whether the costs were unusual compared to costs borne by other similar facilities—which is the test for BACT and the test required by the Administrator's Order. In other words, by relying on other cost-effectiveness determinations that, themselves, were incorrectly done, KDAQ bootstraps its cost effectiveness determination to erroneous analyses.

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[4] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007.

[5] Red Hill costs adjusted to 2006 using the Vatavuk cost index for scrubber: (\$5000)(169.1/120.1). The cost indices are from the journal, Chemical Engineering.

D. The BACT Analysis Must Be Redone To Consider Combinations Of Controls

After the errors in the SOB analysis are corrected, the analysis indicates that low sulfur coal cannot be eliminated based on adverse economic impacts. The record contains no evidence that low sulfur coal is otherwise infeasible for this source. In fact, other BACT analyses, such as for AES Puerto Rico (See Administrator's Order at n.11) and the Cargill CFB, indicate that it is. Thus, clean fuels must be the basis for establishing new SO2 and sulfuric acid mist BACT limits. The SOB assumes that scrubbing and limestone CFB bed can achieve 99.33% SO_2 from low sulfur coal. SOB at 3. As a result, BACT must be 0.02 lb/MMBtu, which is substantially lower than the 0.15 lb/MMBtu BACT limit in the permit, but consistent with other CFB boilers burning low sulfur coal.

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Commonwealth of Kentucky
Division for Air Quality

REVISED STATEMENT OF BASIS AND RESPONSE TO COMMENTS

ON DRAFT TITLE V PERMIT NO. V-06-007 REVISION 2
EAST KENTUCKY POWER COOPERATIVE, INC.
Hugh L. Spurlock Generating Station
MAYSVILLE, KY
MARCH 5, 2008
BEN MARKIN, REVIEWER

SOURCE I.D. #:	21-161-00009
SOURCE A.I. #:	3004
ACTIVITY ID #:	APE2007003

CURRENT PERMITTING ACTION (V-06-007 REVISION 2):

Pursuant to 40 CFR Section 70.7(g)(1), the United States Environmental Protection Agency (EPA) requested that the Kentucky Department for Environmental Protection (KDAQ) submit a proposed permit to modify the existing Title V permit for East Kentucky Power Cooperative's (EKPC) Hugh L. Spurlock Generating Station (Permit No.V-06-007) in accordance with the Administrator's Order (IV-2006-4) responding to a petition submitted by the Sierra Club. Consistent with the Administrator's Order and 401 KAR 52:020 Section 19, the scope of this reopening is limited to the issues related to the maximum heat input for Emission Unit #2 and the consideration of low sulfur eastern bituminous coal in the sulfur dioxide (SO_2) Best Available Control Technology (BACT) determination for Emission Unit 17. The permit has been amended to include a heat input limitation for Emission Unit 2. The underlying basis for the decision to increase the rated heat input of Unit 2 from 4850 MMBtu/hr to 5600 MMBtu/hr is the enforcement action, *U.S. v. East Kentucky Power Cooperative, Inc.*, Case No. 04-34-KSF (E.D. KY), and subsequent consent decree which requires this amendment to the Title V permit. The specific rationale for proposing to increase the limit in this permitting action is the permittee's application for a combined PSD review and Title V permit modification. No revision to the permit has been made regarding low sulfur eastern bituminous coal; however, further explanation for rejecting low sulfur eastern bituminous coal as BACT is provided in this document.

SOURCE DESCRIPTION:

Permitted equipment at the Spurlock Generating Station includes two (2) Pulverized Coal (PC) boilers and two (2) Circulating Fluidized Bed (CFB) boilers.

Emission Unit 01 is a 3500 MMBtu/hr dry-bottom wall-fired boiler equipped with an electrostatic precipitator and low-NO_x burner, for which construction began before 1971. The precipitators were installed as a part of the original plant construction but were rebuilt in 1990-1992. In addition, a selective catalytic reduction device was installed in 2003.

Emission Unit 02 is a 5600 MMBtu/hr tangentially fired boiler equipped with electrostatic precipitators, low-NO_x burners, and a flue gas desulfurization (FGD) system and was subject to review under 40 CFR 52.21 (PSD) in November, 1979. The FGD system is not currently operating, and has not operated since 1985. A selective catalytic reduction device has been installed since the original Title V permit issuance.

Emission Unit 08 is a 2500 MMBtu/hr CFB boiler equipped with a baghouse filter, flash dry absorber (FDA), and a selective non-catalytic reduction (SNCR) unit.

Emission Unit 17 is a 2800 MMBtu/hr CFB boiler that will be equipped with Selective Non Catalytic Reduction (SNCR), Pulse Jet Fabric Filters (PJFF), Dry Scrubbing (DS), and Limestone Injection pollution control systems upon completion of construction.

There is a natural draft cooling tower, coal/limestone/ash material handling equipment, an emergency liquefied petroleum gas generator, and fuel oil storage tanks. The existing natural draft cooling tower, coal/limestone/ash material handling equipment, and fuel oil storage tanks will increase utilization when the new CFB boiler becomes operational.

Pursuant to 401 KAR 52:020 Section 19(2), permit number V-06-007 was reopened for cause and therefore this revision is subject to public notice and comment in accordance with 401 KAR 52:100. This revision only affects the issues related to heat input value for Emission Unit 02 and the consideration of low sulfur eastern bituminous coal in the sulfur dioxide best available control technology determination for Emission Unit 17. Therefore public comment is limited to those two issues.

<u>The following is a list of the emission units affected by this permitting action:</u>

Emission Unit 02: Pulverized Coal-Fired Boiler, 5600 MMBtu/hr

5600 MMBtu/hr tangentially fired boiler equipped with electrostatic precipitator, low-NO_x burners, and a flue gas desulfurization (FGD) system, subject to review under 40 CFR 52.21 (PSD) in November, 1979. The precipitators were installed as a part of the original plant construction but were rebuilt in 1990-1992. The FGD system is not currently operating, and has not operated since 1985; instead, the facility burns low sulfur coal. A selective catalytic reduction device has been installed since the original Title V permit issuance.

<u>Basis for this Revision:</u>

U. S. EPA Administrator's Order in response to Petition Number IV-2006-4. The underlying basis for the decision to increase the rated heat input of Unit 2 from 4850 MMBtu/hr to 5600 MMBtu/hr is the enforcement action, *U.S. v. East Kentucky Power Cooperative, Inc.*, Case No. 04-34-KSF (E.D. KY), and subsequent consent decree which requires this amendment to the Title V permit. The specific rationale for proposing to increase the limit in this permitting action is the permittee's application for a combined PSD review and Title V permit modification.

<u>Permitting Action Taken:</u>

KDAQ has amended the permit to include a heat input limitation of 5600 MMBtu/hr under the "Operating Limits" category of the permit.

Emission Unit 17: Circulating Fluidized Bed Coal-Fired Boiler, 2800 MMBtu/hr

Coal fired Circulating Fluidized Bed (CFB) boiler rating 2800 MMBtu/hr, designed to burn high sulfur eastern bituminous coal, equipped with a baghouse, dry lime scrubber, and SNCR. This unit is permitted to burn Tire-Derived Fuel (TDF), <= 10% coal fuel by weight ratio, and ASTM Grade No.2-DS15 fuel oil for startup and stabilization. Construction on this unit commenced in June 2006.

Supplemental Information:

The U. S. EPA Administrator's Order in response to Petition Number IV-2006-4 required KDAQ to provide further explanation regarding consideration of low sulfur eastern bituminous coal in the SO_2 BACT determination for this unit. To respond to the request of U. S. EPA, KDAQ requested additional information from EKPC regarding the data supplied in EKPC's Supplemental BACT analysis dated January 12, 2006 (misdated as January 12, 2005). EKPC's response contained the following information:

Coal Cost Information

Coal	HHV Btu/lb	SO_2 Content lb/MMBtu	Coal Usage (tons)	$/ton	Total Cost	Δ Cost
Design Coal	10,787	9	1,136,924	$26.15	$29,730,565	baseline
Low -S (E. Bit)	12,500	1.2	981,120	$72.00	$70,640,640	$40,910,075
				$60.00[1]	$58,867,200	$29,136,635
				$50.00[1]	$49,056,000	$19,325,435

[1] Lower $/ton costs presented for analysis.

SO_2 Cost Analysis Based on Fuels Only

Coal	SO_2 In Coal (tons/yr)	SO_2 Emitted (tons/yr)[1]	Δ Emitted (tons/yr)	Cost Comparison ($/ton)
Design Coal	110,376	1,840	baseline	baseline
Low -S (E. Bit) @ $72.00/ton	14,717	246	1,594	$25,665
@ $60.00/ton	"	"	"	$18,279
@ $50.00/ton	"	"	"	$12,124

[1] 98.33% removal efficiency from CFB combustion plus dry scrubber.

EKPC also stated:

> The first lower sulfur eastern bituminous values listed in each table above were provided in EKPC's Response to EPA Region IV's March 15, 2006 Comments, and were based on updated data from the US Coal Review and Coal Outlook. The incremental cost associated solely with the purchase of

entirely lower sulfur eastern bituminous coal rather than higher sulfur coal (design coal) would therefore be the difference in cost of the two coals, which is $40,910,075 per year or $25,665 higher per ton of SO_2 removed. Even assuming the cost of lower sulfur eastern bituminous coal is $50 per ton, the cost per ton of SO_2 removed would be $12,124. This cost differential eliminates the use of lower sulfur eastern bituminous coal as a BACT option. Therefore, the SO_2 permit limit based on design fuel and 98.33% removal efficiency is BACT for Spurlock 4.

In their January 12, 2006 Supplemental BACT analysis, at page 7, EKPC also provided a cost of $45.44/ton for low sulfur eastern bituminous coal. KDAQ has independently researched historical spot and futures prices of low sulfur eastern bituminous coal. Based on historical data, volatility and trends in the coal market, KDAQ believes that it is reasonable to conclude that the long-term cost of low sulfur eastern bituminous coal will not be less than $45.44/ton.

To determine the cost of removal of an additional ton of SO_2 at a coal cost of $45.44/ton, KDAQ performed the following calculations:

$45.44/ton of coal x 981,120 tons of coal used per year = $44,582,093/year.
$44,582,093/yr – $29,730,565 baseline coal cost = $14,851,528/year.
$14,851,528/yr ÷ 1594 additional tons of SO_2 removed/year = $9,317 /additional ton of SO_2 removed.

In considering whether or not $9,317 per ton of additional sulfur removed would be acceptable or excessive for BACT, KDAQ compared this cost to other recent BACT determinations. For this comparison, the most up-to-date and comprehensive analysis found by KDAQ was the amplified SO_2 BACT analysis provided by U. S. EPA in the Response to Public Comments to the Deseret Power Electric Cooperative's Bonanza Power Plant draft permit.

In their Response to Comments, EPA examined recent BACT determinations by permitting authorities for similar projects. Below is a summary of those projects:

1.) Longleaf Energy Associates LLC: The permitting authority (Georgia) determined that a cost increase of $8964 per ton of additional sulfur removed was excessive.
2.) Rocky Mountain Power Inc.'s Hardin County project: The permitting authority (Montana) determined that a cost increase of $23,855 per ton of additional sulfur removed was excessive.
3.) Cargill's Blair corn milling and ethanol production plant: The permitting authority (Nebraska) determined that a cost increase of $5900 per ton of additional sulfur removed was excessive.
4.) Archer Daniel Midlands (ADM) Columbus corn milling and ethanol production plant: The permitting authority (Nebraska) determined that a cost increase of $6700 per ton of additional sulfur removed was excessive.
5.) Red Trail Energy's Richardton North Dakota ethanol production plant: The permitting authority (North Dakota) determined that a cost increase of $10,252 per ton of additional sulfur removed was excessive.

6.) River Hill Power Company: The permitting authority (Pennsylvania) determined that a cost increase of $15975 per ton of additional sulfur removed was excessive. Pennsylvania also indicated that all SO_2 BACT options involving wet FGD systems "were economically infeasible at an incremental dollar per ton value grater than $5000 per ton of SO_2 removed." Pennsylvania concluded that use of a spray dryer absorber or flash dryer absorber (i. e., dry FGD) was "economically feasible for the control of SO_2 at an incremental cost of $1511.01 per ton of SO_2 removed."

7.) Wellington Development's Green Energy Resource Recovery Project: The permitting authority (Pennsylvania) determined that a cost increase of at least $20,000 per ton of additional sulfur removed was excessive.

These examples show that other permitting authorities have rejected additional sulfur removal costs above $5000/ton as being excessive for BACT, and that U. S. EPA has accepted these determinations. Additional sulfur removal at EKPC's Spurlock facility using low sulfur eastern bituminous coal would cost at least $9,317.14/ton. Therefore, KDAQ concurs with EKPC that use of low sulfur eastern bituminous coal is not economically feasible as BACT for Spurlock Emission Unit 17.

PUBLIC AND U.S. EPA REVIEW:

On January 4, 2008, the public notice on availability of the draft permit and supporting material for comments by persons affected by the plant was published in *The Maysville Ledger Independent* in Maysville, Kentucky. The public comment period expired 30 days from the date of publication.

Comments were received from EKPC, Sierra Club and U.S. EPA. Minor changes were made to the permit and the Statement of Basis was expanded as a result of the comments received from EKPC and U.S. EPA. In no case were any emissions standards nor monitoring, recordkeeping or reporting requirements relaxed. The Division has made a final determination to issue a proposed permit. The U.S. EPA has 45 days to comment on this proposed permit. A final permit will be issued after the U.S. EPA's 45-day review.

COMMENTS AND RESPONSE:

Comments on Title V Permit V-06-007 Revision 2

Re: Draft Revised Title V Permit V-06-007 Revision 2
East KY Power Cooperative, Inc.-H.L. Spurlock Power Station
These comments were received from David C. Bender, Attorney for Sierra Club, on February 1, 2008.

These comments are submitted on behalf of the Sierra Club. The Division is proposing to revise the Title V permit for the Spurlock plant to increase the heat rate limit included in the prior state operating permit and to justify the Division's prior failure to consider clean fuel, low sulfur coal in the BACT analysis for SO_2. Both proposals are in error for the reasons set forth below.

As an initial matter, the Division and State of Kentucky have forfeited jurisdiction over the final permit for the Spurlock plant. Following the U.S. EPA Administrator's objection on the Division's prior permit ("Administrator Order"), the Division was required to respond with a permit corrected to meet the Administrator's objections within 90 days. 42 U.S.C. § 7661d(c). The objection was dated August 30, 2007. Ninety days expired on November 28, 2007. The Division failed to submit a revised permit before that date. Neither EPA nor the Division has authority to extend that deadline, notwithstanding EPA's letter purporting to do so. Furthermore, to the extent that the current draft permit was provided to U.S. EPA, it fails to "meet the objection" of the Administrator because it fails to include a 4850 MMBtu/hour heat input limit for Unit 2. 42 U.S.C. § 7661d(c). For each of these reasons, the Division no longer has authority to issue the permit and, instead, U.S. EPA is now the permitting authority.

By submitting these comments Sierra Club does not waive its objection to the Division continuing to assume jurisdiction over the permit. Sierra Club has provided a notice of its intent to sue the U.S. EPA, pursuant to 42 U.S.C. § 7604, to compel the EPA to issue the permits for the Spurlock plant.

Division's response:
The Division does not concur. The Division received notification from U.S. EPA of the Administrator's objection by letter on September 24, 2007. 40 CFR 70.7(g)(4) allows the permitting authority 90 days from the receipt of an EPA objection to resolve the objection and to take permitting action in accordance with the Administrator's objection. Kentucky Division for Air Quality issued the draft permit in a timely manner.

I. THE DRAFT PERMIT DOES NOT MEET THE ADMINISTRATOR'S OBJECTION BECAUSE IT FAILS TO INCLUDE A 4850 MMBTU PER HOUR HEAT INPUT LIMIT FOR UNIT 2.

The basis of the Administrator's August 30, 2007, objection was that the Title V permit failed to include the 4850 MMBtu/ hour heat input limit applicable to Unit 2. The Administrator fist (*sic*) pointed out that the failure of KDAQ to include the 4,850 MMBtu/hour limit from a 1983 state operating permit in a prior, 1999, Title V permit did not revoke the heat input limit. Administrator Order at 12. The Administrator further pointed out that a Title V permit cannot change applicable requirements in underlying permits. *Id.* Therefore, the Administrator found that the 1983 permit limit of 4850 MMBtu/hour remained as an applicable requirement. *Id.*

> Instead, the underlying permit in which the applicable requirement is found must be modified, and then incorporated into the Title V permit as an applicable requirement. Thus, the placement of the maximum heat input in the description section of EKPC's 1999 title V permit could not have eliminated the heat input limit as an applicable requirement of the underlying 1983 SOP.
>
> Based on the foregoing, EPA finds that the title V permit is deficient for its failure to include as an applicable requirement the maximum heat input limit found in the underlying 1983 SOP. Therefore, I grant the petition on this issue and direct KYDAQ to amend the permit and to include the applicable heat input limit for Unit 2 under the "Operating Limits" category of the permit.

Administrator Order at 12 (emphasis added). The "underlying SOP" contains a 4850 MMBtu/hr "maximum heat input" limit. See Kentucky Natural Resources and Environmental Protection

Cabinet PERMIT, Re: H.L. Spurlock Power Station (November 10, 1982) (Attached as Exhibit A). Therefore, to satisfy the Administrator's objection, this 4850 MMBtu/hour maximum heat input limit must be included. The draft permit's proposed 5900 MMBtu/ hour limit does not satisfy the objection

Division's response:

The Division does not concur. First, the commenters' assertion that the draft permit proposes a 5900 MMBtu/hour maximum heat input limit for Unit 2 is in error. The maximum heat input limit for Unit 2 is 5600 MMBtu/ hour. The Administrator stated "KYDAQ must amend EKPC's Title V permit to incorporated the maximum heat input limit from the underlying state permit or EKPC must apply to KYDAQ under the Kentucky SIP for a permit that would authorize a change in that heat input limit, which in turn would be incorporated in the Title V permit." Paragraph 165 of the consent decree between U.S. EPA and EKPC, Civil Action 04-34-KSF, required EKPC to "apply for amendment of its Title V permit for the Spurlock plant to incorporate an MCR of 5600 mmBTU/hr for Spurlock Unit 2." EKPC applied as required by paragraph 165 and thus the draft permit meets the Administrator's objection.

II. INCREASING THE HEAT INPUT LIMIT REQUIRES PSD PERMITTING, AS KDAQ PREVIOUSLY ACKNOWLEDGED.

In addition to failing to satisfy the objection of the Administrator, the draft permit's proposed 5900 MMBtu/ hour limit is an unlawful modification to applicable Clean Air Act Title I standards through a Title V permit.

The 4850 MMBtu/ hour operating limit is required by the PSD permit issued for the original construction of Unit 2. When EKPC applied for a permit to construct Unit 2 in January 1976, EKPC represented to U.S. EPA that EKPC would construct and operate a pulverized coal unit with a maximum heat input of 4850 million Btu/hour. See Letter from Ronald L. Rainson, EKPC, to G.T. Helms, U.S. EPA and attachments (March 19, 1976) (attached as Exhibit B hereto); Letter from William Gill, EKPC, to Frank L. Stanonis, Kentucky Bureau of Environmental Quality, and attachments (January 23, 1976) (attached as Exhibit C hereto). This representation of the 4850 MMBtu/hour maximum heat rate becomes an enforceable requirement because 40 C.F.R. § 52.21(r), which is applicable because the original PSD permit for Unit was issued by U.S. EPA pursuant to Part 52, requires that a PSD applicant construct and operate the source consistent with and according to the specifications provided in its permit application. Additionally, as is apparent from U.S. EPA's review and administrative findings in support of the PSD permit issued for Unit 2, U.S. EPA relied on the maximum 4850 MMBtu/ hour heat input when determining air quality impacts and issuing the permit. See Letter from John A. Little, U.S. EPA to Robert Hughes, EKPC, attaching analysis and permit (September 21, 1976) (attached hereto as Exhibit D).

Additionally, a federally-enforceable state operating permit was issued by Kentucky that limits Unit 2 to 4850 MMBtu/hour. See November 10, 1982 Permit, supra (Exhibit A). For each of these reasons, the 4850 MMBtu/hour limit is an applicable requirement that can only be modified after satisfying all requirements of Clean Air Act Title I. EKPC has not applied for, nor been issued, a pre-construction permit for a heat rate change to Unit 2. Therefore, the Permit must include the existing operational limit of 4,850 million Btu/hour.

The Title V program does not and cannot impose nor change applicable requirements. As the Administrator's Order expressly states — where a state has a merged PSD and Title V program, as Kentucky does—changes to applicable heat rate requirements must be done "outside of the title V part of the process and the rationale for the change must be clearly stated." Administrator Order at 12 n.6. KDAQ cannot include in the revised permit any heat rate limit other than the 4850 MMBtu/hour limit from the original PSD permit and original Kentucky SIP-based operating permit. If EKPC wishes to increase the heat rate, it must undergo PSD permitting and satisfy all other Clean Air Act Title I requirements.

In fact, the KDAQ previously denied EKPC's request to increase the heat rate limit through a prior Title V permit unless EKPC goes through PSD permitting. In December, 1993, East Kentucky sought an increase in the permitted maximum hourly heath input for Unit 2 from 4850 to 5355 MMBtu/hour. Letter from Robert F. Hughes, Jr., EKPC, to John Hornback, KDAQ Re: H.L. Spurlock Power Station- Unit #2 BTU Heat Input (attached hereto as Exhibit E). In February, 1994, KDAQ responded by asserting that any such increase would be considered a major modification under the PSD rules and be subject to PSD permitting requirements if it resulted in a significant net emissions increase. Letter from Gerald R. Goebel, KDAQ, to Robert E. Hughes, Jr., EKPC Re: Request to increase permitted heat input for Unit 2 at the H.L. Spurlock Station (R7532) I.C. # 103-2640-0009 (February 3, 1994) (attached hereto as Exhibit F). Specifically, KDAQ stated that "the Permit Review Branch has determined that if the proposed increase in the heat input rate results in a significant net emissions increase, then your proposal would be a major modification, as defined in Regulation 401 KAR 51:017." *Id.* In January, 1995, EKPC conceded that the 4850 MMBtu/hour heat input cannot be changed without undergoing PSD permitting and rescinded its request for the heat rate increase. Letter from Robert E. Hughes, Jr., EKPC, to Gerald R. Goebel, KDAQ Re: Letter of December 20, 1994 Spurlock Unit 2 (January 16, 1995) (attached hereto as exhibit G).

If there were any doubt as to KDAQ's prior position that a change in the permitted heat rate required a PSD permit, KDAQ reaffirmed that it did in its response to comments on the original Title V permit for the plant. During the public comment process for the 1999 Title V permit, EKPC again requested that the maximum heat rate for Unit 2 be increased to 5600 MMBtu/hour. Response to East Kentucky Power's Comments (3/13/98 Letter) at 2 (attached hereto as Exhibit H). KDAQ again denied the request without PSD permitting, stating:
"As stated in the Division for Air Quality letter dated February 3, 1994, this rating cannot be increased until the demonstration of applicability or nonapplicability of Regulation 401 KAR 51:017, Prevention of significant deterioration of air quality." *Id.*

Despite the fact that Title V permits cannot change applicable requirements, and that KDAQ has previously denied EKPC's requests to modify the heat input limit without PSD permitting, KDAQ is currently proposing to do exactly that: to raise the heat rate from 4850 MMBtu/ hour to 5900 MMBtu/ hour through a Title V revision, and without going through PSD permitting. *See also* Administrator Order at 12 n.7 ("It is apparent that the EKPC was aware that the heat input limit was an enforceable limitation in that it previously requested that KYDAQ revise the maximum heath rate for Unit 2 from 4,850 million [sic] mmBtu/hr to 5,3555 [sic, 5,355] mmBtu/hr. KYDAQ denied EKPC's request when they informed EKPC that a PSD permit was required for such modification.").

KDAQ must include a 4850 MMBtu/ hour limit in the permit. Should EKPC wish to increase this limit, it must apply for the appropriate permits under Clean Air Act Title I (including PSD).

Division's response:

The Division does not concur. See previous response.

III. USE OF CLEAN FUELS IS COST EFFECTIVE FOR SO_2 BACT

The Administrator's objection also concluded that EKPC and KYDAQ did not provide an adequate explanation for rejecting low sulfur coal as not economically viable. Administrator Order at 29-32. In response, the Statement of Basis ("SOB") for the revised permit calculates the cost of using low sulfur eastern bituminous coals as ranging from \$9,317 to \$25,665 per additional ton of SO_2 removed. SOB, p. 4. The SOB then compares this value with incremental cost effectiveness values for other similar projects without disclosing that they were relying on incremental cost effectiveness values. *Id.* Based on this comparison, the SOB concludes that "other permitting authorities have rejected additional sulfur removal costs above \$5,000/ton as being excessive for BACT." *Id.* Therefore, the SOB concludes that additional sulfur removal using low sulfur coal is not economically feasible. *Id.*, pp. 4-5.

This analysis is premised on a number of conceptual errors and, as a result, arrived at an erroneous conclusion. As demonstrated below, the average cost effectiveness of removing additional SO_2 by using low sulfur coal is \$155 to \$427/ton, which is lower than the lower end of the range of average cost effectiveness values for similar sources relied on by KDEQ. Thus, low sulfur fuel is *per se* economically feasible.

A. Average And Incremental Cost Effectiveness Were Not Used

Average and incremental cost effectiveness are the two economic criteria that are used to determine if a control option is economically feasible in a BACT analysis. *NSR Manual,* Sec. IV.D.2. The Administrator's Order cited extensively to EAB cases supporting these two metrics defined as used in the *NSR Manual.* However, EKPC and KYDAQ responded with a single metric which is neither average nor incremental cost effectiveness.

The cost metric used in the SOB is variously called "cost comparison (\$/ton)" and "cost of removal of an additional ton of SO_2." SOB pp. 3-4. This metric is neither average cost effectiveness nor incremental cost effectiveness and, in fact, has no basis in the practice of top-down BACT analyses. KDAQ's analysis compares the cost of fuel switching with the reductions achieved by a three-stage-control option using design coal: fuel switching, limestone addition to the CFB bed, and dry scrubbing. This is an erroneous and misleading comparison. The SOB also compares this unrecognized cost-effectiveness standard with incremental cost effectiveness values as specified in the Administrator's Order for a wholly different set of pollution controls.

The SOB calculates a single cost value, which purports to be incremental cost effectiveness, but upon close examination, is not. The SOB's cost metric is calculated as the ratio of the incremental fuel cost to the incremental amount of SO_2 emitted.

First, the SOB calculates the difference in the annual cost to purchase the design fuel (9 lb SO_2/MMBtU and 10,757 Btu/lb) compared to the cost to purchase low sulfur fuel (1.2 lb SO_2/MMBtu and 12,500 Btu/lb) in dollars per year:

[Annual Cost of Design Coal — Annual Cost of Low S Coal] *(1)*

• Second, the SOB calculates the amount of SO_2 emitted when burning design fuel compared to the amount of SO_2 emitted when burning low sulfur coal in tons per year, <u>assuming 99.33% SO_2 removal in both cases</u> using limestone additions to the CFB bed and a dry scrubber:

[SO_2 *Emitted Design Coal* — SO_2 *Emitted Low S Coal]* *(2)*

• Finally, the SOB divides the incremental annual fuel cost by the incremental amount of SO_2 emitted and calls the results the cost per <u>additional ton</u> of SO_2 emitted. As an example, the lower end of the SOB's cost range is calculated as:

[$44,582,093/yr - $29,730,565/yr]/[1 840 ton/yr — 246 ton/yr] = ***$9,317/ton***

This result is neither average cost effectiveness nor incremental cost effectiveness, the metrics required by the Administrator's Order and the typical metrics used in PSD permitting. Further, the SOB's method of calculating cost are incorrect and substantially penalize low sulfur fuel by including SO_2 emission reductions achieved by other control options and excluding the relative costs of these other controls.

This value is not average cost effectiveness because average cost effectiveness is the ratio of the <u>control option</u> annualized cost divided by the <u>control option</u> annual emission reduction. *NSR Manual* at B.36-B.37. This value is also not incremental cost effectiveness because incremental cost effectiveness is the ratio of the difference in annualized cost of two <u>control options</u> to the difference in the emission rates of these same two <u>control options.</u> *NSR Manual* at B.41. In both cases, cost effectiveness is the ratio of costs of a **control option(s)** to emission reductions achieved by that control option(s). This is not what is calculated in the SOB.

Instead, the SOB calculates **control option** [low S coal] annualized cost divided by SO_2 emission reductions from the entire control train [low S coal + limestone bed + dry scrubber]. For incremental cost effectiveness, the annual emission reductions due to the use of low sulfur coal should be the difference between SO_2 in the design coal and SO_2 in the low sulfur coal or 95,659 ton/yr [110,376-14,717], not 1,594 ton/yr [1840-246]. The use of the lower value, after the post-combustion controls-- for emission reductions attributable to the lower sulfur coal artificially inflates cost effectiveness of low sulfur coal. KDAQ's analysis divides annual cost by incremental emission reductions, resulting in a calculated reduction that is 60 times smaller than it should be.

Correcting this error, incremental cost effectiveness of using a low sulfur coal ranges from \$155/ton to \$427/ton[1].' These values are below the lower end of the range of both average cost effectiveness (\$527 to \$4054/ton) and incremental cost effectiveness (\$5,000-20,000/ ton) relied upon by the SOB (which are also lower than other permitting authorities use).[2] Thus, the use of low sulfur coal is cost effective and cannot be eliminated based on cost effectiveness.

The use of emission reductions from the entire pollution control train to calculate cost effectiveness is also wrong because it includes reductions from adding limestone to the fluidized bed and dry scrubbing, but does not consider the relative costs of these additional controls when using design coal as compared to low sulfur coal. In other words, KDAQ's analysis attributes all of the reduction but none of the cost from limestone injection and scrubbing to the high sulfur coal when comparing the cost effectiveness of high and low sulfur coal. For the high-sulfur, "design coal," the limestone bed plus dry scrubber must reduce SO_2 emissions from 110,376 ton/yr to 1,840 ton/yr, or by **108,536** ton/yr. For low sulfur coal, these controls need only reduce SO_2 from 14,717 ton/yr to 246 ton/yr or by **14,471** ton/yr. SOB, p. 3. The cost to remove **108,536** ton/yr of SO_2 with limestone injection and a scrubber when burning design fuel is substantially higher than the cost to remove only 14,471 ton/yr when burning low sulfur coal. The economic benefit of controlling less SO_2 with lower sulfur coal is not considered in the SOB.

The control costs for design fuel for the entire control train is higher than for low sulfur coal because a bigger, more efficient scrubber must be used; more limestone must be added to the fluidized bed; more water must be used to cool the flue gases; more solid wastes must be disposed; more electricity must be used to operate the scrubber; and more lime must be injected into the scrubber, among other increased costs incurred for the complete control trains as compared to just low sulfur coal. If the cost of these additional controls were included in both the cost of design coal and the low sulfur option, they would add substantially to the design coal costs and much less so to the low sulfur coal, thus narrowing the incremental cost. This would reduce incremental cost effectiveness. This is the reason that cost-effectiveness must look at the entire pollution control train— rather than attempting to add one piece (low sulfur coal) to a control train that is designed around a different input (high sulfur coal).

B. The Comparative Costs Are Not Representative

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[1] The lower end of the range from SOB, p. 4: (\$14,851,528/yr)/(95,659 ton SO_2/yr) = *\$155/yr.* The upper end of the range from SOB, p. 3: (\$40,910,075/yr)/(95,659 ton SO_2/yr) = \$427.67/ton

[2] U.S. EPA Region 8, Response to Public Comments on Draft Air Pollution Control Prevention of Significant Deterioration (PSD) Permit to Construction, Deseret Power Electric Cooperative, August 30, 2007, pp. 29-33

The SOB compares a metric it calls "cost comparison" or "dollars per additional ton of SO_2 removed" for using fuel switching to incremental cost effectiveness values for post combustion controls -- various types of dry scrubbers and sorbent injection. SOB, p. 4[3] This is an apples-to-oranges comparison that creates a number of errors in KDAQ's analysis.

First, even assuming the SOB correctly calculated cost effectiveness (which it did not), the *NSR Manual* explains that "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those sources and the particular source under review." *NSR Manual* at 31 (emphasis added except as to "any"). In other words, the cost of controlling additional SO_2 with low sulfur coal must be compared to the costs incurred by other plants that burn low sulfur coal. The *NSR Manual* elaborates that: "..if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT." *NSR Manual,* p. B.44 (emphasis added).

The comparison, then, must be on a "control technology" basis, not a pollutant basis. Neither EKPC nor KDAQ appear to have undertaken a comparison of the cost of fuel switching borne by other sources that have used fuel switching as a pollution control method with the cost of fuel switching in this instance at the Spurlock 4 unit. The record contains no comparative cost data for fuel switching as a control option. It is incorrect to compare the cost of scrubbing and sorbent injection, which are separate and distinguishable SO_2 control technologies, to the cost of fuel switching.

Second, cost comparisons should be made on an "apples-to-apples" basis. E.g., *NSR Manual* at B.39 (stating that a source that compares costs between options must do so with standard assumptions for all options, discussing an 85% capacity factor in that case). The comparative cost data are based on incremental cost effectiveness, calculated as explained in the *NSR Manual* at p. B.41. These values compare the cost of a wet scrubber with the cost of a dry scrubber — a one to one comparison. However, the SOB then attempts to compare the fuel costs, alone, to the emission reductions based on low sulfur coal plus both a limestone CFB bed and a dry scrubber. This distorts the comparison and inflates the cost per ton calculation.

Further, the EPA cost data are not otherwise directly comparable as they are based on different assumptions as to capacity factor (Longleaf, for example, assumed 85%), SO_2 control efficiency (Cargil, for example, assumes only 75% SO_2 control efficiency for SDA while others assume 90%+), interest rate, and equipment life, factors that must be constant from plant to plant to be used in a comparative cost analysis. KDAQ's analysis fails to account for these differences.

C. KDAQ Failed to Use Range Of Comparative Cost Data

[3] The SOB does not disclose the control technology, but the source of the comparative cost data, EPA's response to comments in the Desert case, does disclose the controls.

First, the SOB compared the cost value it calculated, \$9,317/ton, with the lower end of the range of the reported comparative cost data. The incremental cost data summarized from EPA ranges from \$5,000/ton to \$23,855/ton. A control option is considered cost effective if it is "within the range of normal costs for that control alternative..." *NSR Manual* at B.31 (emphasis added). All of the cost values reported in the SOB, which range from \$9,317/ton to \$25,665/ton are well within the range of reported comparative cost data. The SOB has provided no justification for focusing on a single determination by Pennsylvania for the River Hill CFB.

Second, the one determination relied on by KDAQ, River Hill, is based on an Application submitted in July 2004. Pollution control costs have escalated dramatically since then.[4] As a result, what is cost effective today may be greater, in unadjusted dollars, than what was considered cost effective four years ago. Moreover, the SOB cost calculations are based on 2006 dollars. By adjusting the 2004 River Hill cost data (based on scrubbers) to 2006 dollars-- using the Vatavuk cost index-- the \$5,000/ton value relied on by KDAQ becomes \$7,040/ton in 2006 dollars.[5] Adjusting to current dollars would result in a similar increase. Moreover, this \$7,000/ ton value is within about 30% of the cost value proffered by KDAQ, \$9,317, and thus, even under KDAQ's limited use criterion, is cost effective. *NSR Manual* B.44 ("Study cost estimates used in BACT are typically accurate to +/- 20 to 30 percent. Therefore, control cost options which are within +/- 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options."). The cost of low sulfur coal at Spurlock 4 is certainly "on the same order" as the River Hill cost, when adjusted for inflation. *NSR Manual* B.44 ("if the cost.. . is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT.") Thus, low sulfur coal is cost effective even under KDAQ's incorrect metric for calculating the cost per ton.

Third, the next lowest value used for comparison suffers similar problems. Nebraska required the applicant to use lower sulfur coal than proposed, 2.7 lb SO_2/MMBtu compared to its proposal of 3.57 lb SO_2/MMBtu. In that case, lower sulfur coal was economic. Cargil Final Permit at pdf 32. The cost effectiveness value of \$5,900/ton corresponds to an additional reduction of only 75% above limestone injection using a dry scrubber, which is not representative of the instant case.

Fourth, none of the comparative cost data the SOB relies on used comparative cost data to determine whether the costs were unusual compared to costs borne by other similar facilities — which is the test for BACT and the test required by the Administrator's Order. In other words, by relying on other cost- effectiveness determinations that, themselves, were incorrectly done, KDAQ bootstraps its cost effectiveness determination to erroneous analyses.

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[4] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007.

[5] Red Hill costs adjusted to 2006 using the Vatavuk cost index for scrubber: (\$5000)(169.1/120.1). The cost indices are from the journal, Chemical Engineering.

D. The BACT Analysis Must Be Redone To Consider Combinations Of Controls

After the errors in the SOB analysis are corrected, the analysis indicates that low sulfur coal cannot be eliminated based on adverse economic impacts. The record contains no evidence that low sulfur coal is otherwise infeasible for this source. In fact, other BACT analyses, such as for AES Puerto Rico (See Administrator's Order at n.11) and the Cargill CFB, indicate that it is. Thus, clean fuels must be the basis for establishing new SO_2 and sulfuric acid mist BACT limits. The SOB assumes that scrubbing and limestone CFB bed can achieve 99.33% SO_2 from low sulfur coal. SOB at 3. As a result, BACT must be 0.02 lb/MMBtu, which is substantially lower than the 0.15 lb/MMBtu BACT limit in the permit, but consistent with other CFB boilers burning low sulfur coal.

Division's response:
The Division does not concur. In accordance with the Administrator's objection, DAQ revised the statement of basis for permit V-06-007 Revision 2 to include justification for excluding low sulphur eastern bituminous coal as BACT for SO_2. DAQ included such justification in the Statement of Basis for this permit. By letter dated February 27, 2008, U.S. EPA informed DAQ that "[t]he draft permit revision, more specifically the statement of basis adequately addresses the requirement to provide sufficient justification for eliminating low-sulfur eastern bituminous coal as best available control technology (for sulfur dioxide emissions) for Emission Unit 17 (Unit #4)." Therefore the objection has been resolved.

Re: Draft Revised Title V Permit V-06-007 Revision 2
East KY Power Cooperative, Inc.-H.L. Spurlock Power Station
These comments were received from Greg M. Worley of U.S. EPA Region 4 on February 29, 2008.

We have completed our review of the draft permit revision for East Kentucky Power Cooperative — Hugh L. Spurlock Station [V-06-007(R2)], which seeks to address the Administrator's Order (IV-2006-4) responding to a petition submitted by the Sierra Club. Our initial comments are as follows:

1) The draft permit revision adequately addresses the requirement to include the applicable maximum continuous heat input rating (MCR) as an operating limit for Unit #2 in the appropriate section of the title V permit. However, the statement of basis does not explain the proposed increase in the underlying MCR (from 4850 to 5600 MMBtu/hr). Because the original 4850 MMBtu/hr heat input was an operating limit in the underlying prevention of significant deterioration (PSD) permit, the statement of basis needs to provide an adequate basis for a decision to increase the limit, such as providing details of previous events [e.g., the enforcement action, *U.S. v. East Kentucky Power Cooperative, Inc.,* Case No. 04-34-KSF (E.D. KY), and subsequent consent decree] as well as the specific rationale for proposing to increase the limit in this permitting action (i.e., the permittee's application for a combined PSD review and title V permit modification) that resulted in the change in the MCR value.

Division's response:
The Division acknowledges the comment and the Statement of Basis has been expanded accordingly.

2) The draft permit revision, more specifically the statement of basis, adequately addresses the requirement to provide sufficient justification for eliminating low-sulfur eastern bituminous coal as best available control technology (for sulfur dioxide emissions) for Emission Unit 17 (Unit #4).

Division's response:
The Division acknowledges the comment.

Re: Draft Revised Title V Permit V-06-007 Revision 2
East KY Power Cooperative, Inc.-H.L. Spurlock Power Station
These comments were received from Jerry Purvis of EKPC on January 23, 2008.

On page 7 of 95 of the draft permit, the Emission Unit 02 Description indicates that the pulverized coal-fired boiler is rated at 4850 MMBtu/hr. This is contradictory to the Emission Unit 02 Operating Limitation of 5600 MMBtu/hr. EKPC respectfully requests that the rate of 4850 MMBtu/hr be deleted from the Description of Emission Unit 02. The revised first line of the Description would read as follows:
"Pulverized coal-fired boiler, dry bottom, tangentially-fired
equipped with low NOx burners"

Additionally, item (3) on page 95 of the draft permit lists affected units, including "one(1) 4850 MMBtu/hr tangentially fired boiler.... " For consistency, the reference to 4850 MMBtu/hr should be changed to 5600 MMBtu/hr.

Division's response
The Division acknowledges the comment, and the editorial errors have been corrected in the permit.

~~XXXXXXXXXX~~

EXHIBIT E

Kentucky Natural Resources and Environmental Protection Cabinet
Department for Environmental Protection
Division of Air Pollution Control

PERMIT

EAST KENTUCKY POWER COOPERATIVE
P.O. Box 707
Winchester, Kentucky 40391

RE: H.L. Spurlock Power Station

Pursuant to your application which was concluded by this office to be complete on June 15, 1982, the Natural Resources and Environmental Protection Cabinet, by authority of Kentucky Revised Statutes Chapter 224, issues this permit for the operation of the equipment specified herein in accordance with the plans, specifications, and other information submitted with your application. This permit is subject to all conditions and operating limitations contained herein.

POINT OF EMISSION		AFFECTED FACILITY	CONDITIONS
01	(1)	Indirect Heat Exchanger (Unit 1)	2825 mmBTU/hr maximum heat input.
02	(2)	Indirect Heat Exchanger (Unit 2)	4850 mmBTU/hr maximum heat input.
03	(1A)	Indirect Heat Exchanger (Auxiliary Boiler)	144 mmBTU/hr maximum heat input.
04	(-)	Coal Handling	2,922,628 tons/yr maximum thruput.

GENERAL CONDITIONS:

1. Malfunction and shut down of air pollution control equipment shall be promptly reported to the Division in accordance with Regulation 401 KAR 50:055, Section 1.

2. Fugitive emissions shall be controlled in accordance with Regulation 401 KAR 63:01(

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 of Air Pollution Control. This permit shall become null and void at any time the terms and conditions contained herein are violated. All rights of inspection by the representatives of the Division of Air Pollution Control are reserved. Responsibility of satisfactory conformance to all Air Pollution Control Regulations must be borne by the permittee.

PERMIT NUMBER: 0-82-270
FILE NUMBER: 103-2640-0009
REGION: Ashland
COUNTY: Mason
SIC CODE: 4911

Issued this 10th day of November 19 82

Jackie Swigert
Secretary, Natural Resources & Environmental Protection Cabinet

Director, Division of Air Pollution Control

DEP7001

PERMIT NUMBER: 0-82-270

PERMIT - Continued

3. Emissions from Unit 1 shall not exceed the following limitations:
   Particulate - 0.22 #/mmBTU heat input
   SO_2 - 6.0 #/mmBTU heat input

4. Emissions from Unit 2 shall not exceed the following limitation:
   Particulate - 0.1 #/mmBTU heat input
   SO_2 - 1.2 #/mmBTU heat input
   NO_x - 0.7 #/mmBTU heat input

5. The company shall maintain and make available for inspection by this Division, all production records necessary to assure that the allowable annual coal consumption rate will not be exceeded.

6. Emissions from Unit 1 shall be monitored and reported in accordance with Regulatio 401 KAR 61:005, Section 3.

7. Emissions from Unit 2 shall be monitored and reported in accordance with Regulation 401 KAR 59:015, Section 7 and 59:005, Sections 3 and 4.

8. The permittee is hereby required to contact the Division of Waste Management in order to comply with the requirements in the Solid Waste Regulations.

9. The permittee is hereby required to contact the Division of Water and the Division of Permits in order to satisfy the requirements of those Divisions.

10. In no way does this permit relieve the permittee from compliance with all applicable emission and air quality standards.

11. The previous operating permit (0-78-11) for Unit 1 issued on February 24, 1978 is hereby null and void.

12. All control devices shall be properly maintained, kept in good operating condition, and used in conjunction with their associated affected facility at all times.

13. Whenever non-compliance coal is burned in Unit #2, i.e. coal which will produce uncontrolled emissions of sulfur dioxide in excess of 1.2 pounds per million BTU, the following conditions shall be met:

   a) Sufficient flue gases shall pass through the FGD system such that sulfur dioxide emissions shall not exceed 1.2 pounds per million BTU.

   b) Written notification postmarked within 15 days, of the date use of non-compliance coal began.

   c) Within 15 days after demonstration of compliance, an application for a permit to operate.

   d) Within 60 days after achieving the maximum firing rate using non-compliance coal, but not later than 180 days after initial use of non-compliance coal, the owner or operator shall conduct performance tests on Unit #2 when combusting the non-compliance coal and furnish the Division a written report of the results of such performance tests.

PERMIT - Continued

13. e) At least 15 days prior to the date of the required performance test(s), the permittee shall contact the Division to schedule a meeting for the purpose of establishing performance test protocol. The Division shall be notified of the actual test date at least 10 days prior to the tests.

f) 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 use of non-compliance coal.

XXXXXXXXXXX

EAST KENTUCKY POWER COOPERATIVE, Inc.

4758 Lexington Road (40391)
P.O. Box 707
Winchester, Kentucky 40392-0707
Tel. (606) 744-4812
Fax. (606) 744-6008

December 15, 1993

Mr. John Hornback, Director
Division for Air Quality
316 St. Clair Mall
Frankfort, Kentucky 40601

Dear Mr. Hornback:

Subject: H. L. Spurlock Power Station - Unit #2
BTU Heat Input

East Kentucky Power Cooperative, Inc. (EKPC) has been reviewing the permit status of its facilities. In the early 1980's, when EKPC obtained the operating permit for the above facility, the boiler heat input was supplied on the application based upon average fuel burn rate and average fuel quality. The number provided to the Division and the number that is identified on our operating permit is $4850X10^6$BTU/Hour.

EKPC, working with the Department of Commerce and other branches of state government, assisted in the location of Inland Container near our facility. Inland Container requires both electric power and live steam to operate. EKPC has found that, due to the design of our facility and without any plant modification, it would be possible to reach peak electric load and still provide the steam necessary for Inland Container operation. Accomplishing both of the goals could result in an exceedance of our printed heat input to the boiler.

We have met on a number of occasions with your permitting staff and review this situation. Your staff has requested that we submit a formal request to change this heat input value. Therefore, we would request that the permitted heat input for this unit be increased to $5355x10^6$BTU/Hour.

If you have any questions, please contact me.

Sincerely,

Robert E. Hughes, Jr.

Robert E. Hughes, Jr., *Manager*
Environmental Affairs

REH:bwr

c: Hubert Smith
Sam Holloway

OPTIONAL FORM 99 (7-90)
FAX TRANSMITTAL
# of pages ▶ 2
To Diana Antkowiak/John Lyons
From David Lloyd
Dept./Agency
Phone #
Fax #
Fax #
NSN 7540-01-317-7368 5099-101 GENERAL SERVICES ADMINISTRATION

EXHIBIT F

10-13-2000

P 3 7

PHILLIP J. SHEPHERD
SECRETARY

BRERETON ... 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

February 3, 1994

RECEIVED
FEB 7 1994

Mr. Robert E. Hughes, Jr.
Manager, Environmental Affairs
East Kentucky Power Cooperative, Inc.
P.O. Box 707
Winchester, Kentucky 40392-0707

RE: Request to increase permitted heat input for Unit 2
at the H.L. Spurlock Station (R7532)
I.D. #103-2640-0009

Dear Mr. Hughes:

This letter is in response to your December 15, 1993, letter to the Division. The Permit Review Branch has determined that if the proposed increase in the heat input rate results in a significant net emissions increase, then your proposal would be a major modification, as defined in Regulation 401 KAR 51:017.

Therefore, you are required to quantify the emissions from your proposal in order to demonstrate the applicability or non-applicability of Regulation 401 KAR 51:017, Prevention of significant deterioration of air quality. You are requested to submit this information by February 28, 1994.

If you have any questions, please contact Mr. Roger S. Cook at (502) 564-3382, extension 308.

Sincerely,

Gerald R. Goebel

Gerald R. Goebel, Assistant Manager
Permit Review Branch

GRG:MRE:mlc

cc: Roger S. Cook
William A. Clements/Regional Office

bcc: Miles M. Smith
James W. Dills
Source File/6

EXHIBIT G

bcc: Gerald R. Goebel
Source File/6

EAST KENTUCKY POWER COOPERATIVE, inc.

4758 Lexington Road (40391)
P.O. Box 707
Winchester, Kentucky 40392-0707
Tel. (606) 744-4812
Fax. (606) 744-6008

January 16, 1995

Gerald R. Goebel, Assistant Manager
Permit Review Branch
Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601-1403

Subject: Letter of December 20, 1994
Spurlock Unit 2

Dear Sir:

We are currently reviewing the operating status of our units and would request that our proposal to increase the permitted heat input be withdrawn at this time.

We will review the facility operation and its future planned use and will evaluate the need to continue this process at a later date.

Thank you for your help with this review

Sincerely,

Robert E. Hughes Jr.

Robert E. Hughes, Jr., ***Manager***
Environmental Affairs

REH:mdt

EXHIBIT H

XXXXXXXXXXXX

JAN 14 '03 10:23AM DIV. AIR QUALITY P.3/12

Maysville
File section 6
103-2640-0009

East Kentucky Power Cooperative

"A Rural Electric Cooperative Corporation"

P. O. Box 707 · Lexington Road · Winchester, Kentucky 40391 · 606-744-4812

March 19, 1976

Mr. G. T. Helms, Deputy Director
Air and Hazardous Materials Division
Region IV - U.S. EPA
1421 Peachtree Street, N.E.
Atlanta, Georgia 30309

Attention: Mr. Winston Smith

Dear Mr. Helms:

Subject: "Air Pollutant Emissions Report"

Enclosed is a completed "Air Pollutant Emissions Report" and supplemental information for power plants.

I hereby certify that the information contained in the above report is valid and complete to the best of my knowledge and belief.

Sincerely,

EAST KENTUCKY POWER COOPERATIVE, INC.

Ronald L. Rainson, P.E.
General Manager

WEG:ln

Enclosures
(1) Air Pollutant Emissions Report
(2) Drawings (2 each)
 (a) Maysville West Quadrangle Map
 (b) Site Layout
 (c) Process Flow Diagram
 (d) Unit I Chimney Interior Platform
 (e) Unit I Sample Port Platform
 (f) Unit II Chimney With Plastic Liner
(3) Pollutant Emission Calculations

EXHIBIT I

James S. Patterson, President
Phil Dean, Vice President

Date Report Submitted: March 19, 1976

ENVIRONMENTAL PROTECTION AGENCY
AIR POLLUTANT EMISSIONS REPORT

FORM APPROVED
OMB NUMBER 158-R75

SECTION II - FUEL COMBUSTION FOR GENERATION OF HEAT, STEAM, AND POWER

Plant, institution, or establishment name: Hugh L. Spurlock Power Station, East Kentucky Power Cooperative

Normal operating schedule for fuel use: 24 Hours per day 7 Days per week 52 Weeks per year 8760 Hours per year.

Dates of annually occurring shutdowns of operations: April or October (1). Additional operating information enclosed ☐.

Source[a,e] Code	Number of Combustion Sources[b,e] (Boilers)	Size of Unit (Input)[c,e] 10^6BTU/hr.	Type of Unit[d,e]	Installation Date[e]	Percent Excess Air Used In Combustion (Design)[e]	Power Output Megawatts[e,f]
UNIT 1	1	2825 (2)	Pulverized, Dry Bottom Without Fly Ash Reinjection	Sept. 1976	20 (4)	317
UNIT 2	1	4850 (3)	Pulverized, Dry Bottom Without Fly Ash Reinjection	Sept. 1980	25	526

a. List a separate code number to represent each source (e.g., II-a, II-b, II-c, etc.), then enter the same code number and the required data on the continuation of this Section on Page 3, and in Sections V and VI.

b. Multiple sources may be grouped if units are similar in size and type, burn the same fuel, or are vented to the same stack.

c. Nameplate data are sufficient (give rated or maximum capacity, whichever is greater).

d. Hand-fired, underfeed, overfeed, traveling-grate or spreader stoker; cyclone furnace; pulverized, wet or dry bottom with or without fly ash reinjection; rotary or gun type oil burner; etc.

e. List separately future equipment and expected date of installation.

f. Power generation only.

(1) BASED ON POWER DEMAND
(2) PEAK INPUT 3022 x 10^6 Btu/hr.
(3) PEAK INPUT 5120 x 10^6 Btu/hr.
(4) AT BOILER OUTLET

NOTE: Please read reverse side of this page. Use additional sheets if necessary. Retain last copy.

DEPARTMENT FOR NATURAL RESOURCES AND ENVIRONMENTAL PROTECTION
Division of Air Pollution
Frankfort, Kentucky 40601

PERMIT APPLICATION FOR AIR CONTAMINANT SOURCE

ADMINISTRATIVE INFORMATION

e completion and return of this form is required under Regulation No. 401 KAR 3:010, Permit to Construct and Operate Air Contaminant Source, pursuant to the Kentucky Air Pollution Control Law. Applications are incomplete unless accompanied by copies of all plans, specifications and drawings. Failure to supply information required or deemed necessary the Division to enable it to act upon the Permit Application shall result in denial of the permit.

Name of Firm or Institution: East Kentucky Power Cooperative, Inc.

Mailing Address: *Number*	Box 707 *Street*	Winchester *City*	Clark *County*	40391 *Zip*
Facility Location: *Number*	Box 398 *Street*	Maysville *City*	Mason *County*	41056 *Zip*

Previous Registration, Identification, or Permit Numbers:

General Nature of Business: Electric Generation Station, SIC 4911

Type of Permit Required:

Pursuant to the provisions of Regulation No. 401 KAR 3:010 of the Kentucky Division of Air Pollution, application is hereby made for authority to construct __x__ or operate ______ an air contaminant source.

Estimated cost of equipment or of alteration.

Total Facility (including existing air pollution control equipment)	$ 250 million
Air Pollution Control Equipment existing as of date of application	$
New Air Pollution Control Equipment to be installed	$ 18.5 million
Modification to existing Air Pollution Control Equipment	$

Present status of equipment: (Check and complete applicable items)

(a) For Existing Facilities: Date Construction Completed __________

(b) Equipment to be modified or constructed

Basic Equipment ☒
Air Pollution Control Equipment ☒

(c) Transfer of ownership pending ☐

Log # _ _ _ _

(d) Transfer of location pending ☐

For b, c, or d:

Estimate starting date 1976

Estimate completion date 1980

9. The following forms are attached and made a part of this application: (Indicate quantity of each form)

x APC 110A Indirect Heat Exchanger
___ APC 110B Manufacturing or Processing Operations
___ APC 110C Incinerators and/or Waste Burners
___ APC 110D Coal Refuse Areas
x APC 110E Monitoring Equipment
x APC 110F Episode Standby Plan
x APC 110G Compliance Schedule

10. Other attachments are as listed and are part of the official submittal. (Site Plan Required)

Attachment A - Flow Diagram
Attachment B - Air Pollution Control Site Layout
Attachment C - Steam Gen. Specs - Electrostatic Precipitator
Attachment D - Analysis Unit 2-345 Transmission Line
Attachment E - Topo Map (3)
Attachment F - Ambient Monitoring Specs.

11. Are any of the following materials emitted into the atmosphere from any operation or process at this location? (Check the applicable item(s)). N.A.

___ Arsenic ___ Beryllium ___ Lead ___ Silica

___ Asbestos ___ Cadmium ___ Mercury

12. Signature, title, phone number of person submitting application as required by Regulation 401 KAR 3:010.

Date of Application

Ronald L. Rainson, General Manager January 22, 1976

East Kentucky Power Cooperative, Inc.

P. O. Box 707
Winchester, Kentucky 40391
Phone 606/744-4812

For Office Use Only

UTM Coordinates

Horizontal _ _ _ . _

ID Number _ _ _ _ _ _ _ _

Vertical _ _ _ _ . _

DEPARTMENT FOR
NATURAL RESOURCES AND
ENVIRONMENTAL PROTECTION
DIVISION OF AIR POLLUTION
FRANKFORT, KENTUCKY 40601

Log # ____

INDIRECT HEAT EXCHANGER

Point of Emission Number 02

1. A completed form (No. APC 110A) shall be submitted for each individual unit. The following types of units are exempted from this portion of the application:

_____ A. Indirect heat exchangers used solely for heating residential buildings not exceeding a total of six apartment units;

_____ B. New installations with a capacity of less than 1 million BTU per hour input;

_____ C. New installations using natural or liquified petroleum gas, including those having distillate fuel oil as standby fuel with a capacity of less than 50 million BTU per hour input;

_____ D. Marine installations and locomotives;

_____ E. Internal combustion engines and vehicles used for transportation of passengers or freight.

If your indirect heat exchanger is in one of the above categories please check that category and complete only items 7, 8, 9.

New installations are those for which construction commenced after April 9, 1972.

Type of Unit Steam Generator . A. Manufacturer's Name Combustion Engineering

B. Manufacturer's Model Number N.A. C. Date Installed ____

Rated Capactiy-Input (BTU/Hr.) approximately 4850 x 10^6 BTU/HR

Type of Combustion Unit (Coal) With fly ash reinjection ____ Without fly ash reinjection X

A. Pulverized
Dry Bottom X
Wet Bottom ____

B. Cyclone ____

C. Stoker-fired
Spreader Stoker ____
Other Stoker ____

D. Hand-fired ____

E. Other (Specify) ____

Type of Combustion Unit (oil)

A. Tangentially-fired ____
B. Horizontally-fired ____

Type of Combustion Unit (Wood)

With fly ash reinjection ____ Without fly ash reinjection ____

A. Pile ____
B. Thin Bed ____
C. Cyclonic ____

INDIRECT HEAT EXCHANGER (CONT'D)

Log # ____

Type and Quantity of Fuel (List both primary and standby):

Type of Fuel	Percent Ash* Min.	Percent Ash* Max.	Percent Ash* Avg.	Percent Sulfur* Min.	Percent Sulfur* Max.	Percent Sulfur* Avg.	BTU per Unit** (specify units) Min.	BTU per Unit** (specify units) Max.	BTU per Unit** (specify units) Avg.
Coal			11.0			0.66			11,500/lb
Fuel Oil 1,2,4,5,6, (Circle One)			Trace	0.4	0.7				19,350/lb.
Natural Gas									
Propane									
Butane									
Wood									
Other ______									

Type of Fuel	Units	Qty. Per Yr.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Coal	Tons	approximately 1.5 million												
Fuel Oil 1,2,4,5,6 (circle one)	Gallons	ignition purposes only												
Natural Gas	MCF (10^3 cu. ft.)													
Propane	Gallons													
Butane	Gallons													
Wood	Tons													
Other ______														

Fuel Source N.A.

Normal Operating Schedule:

52 Weeks per year, 7 Days per week, 24 Hours per day

* As received basis. (Proximate analysis for ash, ultimate analysis for sulfur)
** Higher heating value.

Log # ----

10. Purpose (If multipurpose, describe percent in each use category)

Space Heat ________
Process Heat ________
Power Electric Generation

11. Type of Control Equipment

	Control Efficiency Particulates	SO_2	Other (Specify)	Basis of Estimate
x Electrostatic Precipitator	99.5			design specifications
Cyclone				
Multiple Cyclone				
Wet Scrubber				
Settling Chamber				
Other (Specify)				

12. Stack
Stack specifications to be determined
A. Outlet temperature 285.3 °F
B. Outlet velocity 90.9 ~~98.4~~ ft/sec
C. Height 805 feet 440 - Liner
D. Inside diameter (outlet) ~~300~~ inches
E. Number of sampling ports provided N.A.
F. Nearest distance from sampling port downstream to stack outlet, bend or obstruction N.A. feet
G. Nearest distance from sampling port upstream to bend or obstruction N.A. feet
H. List other sources vented to this stack

3. Combustion air: Natural draft ________ Induced x
Forced pressure ________ lbs./sq.in.
Excess air (total air supplied in excess of theoretical air required) ~~20~~ 25 %

4. Describe fuel transport, storage methods and related dust control measures.
Coal will arrive by both barge and rail. Barges will be emptied by a barge unloader that is to be constructed. Rail cars will be unloaded by a rotary car dump present in Unit 1. From either barge or rail, coal is sent to a crusher house. From there it is either sent to the stockpile or into the power station for use. All conveyors are covered and all open transport is equipped with dust suppression equipment. Storage areas are open and compacted.

5. Describe fly ash (or other collected air contaminants) disposal, transportation methods and related dust control measures.

Fly ash and bottom ash are removed and sluiced with water into an open ash pond for storage. A water level is maintained above the ash to prevent dust problems.

. Attach manufacturer's literature and guaranteed performance data for the indirect heat exchanger and air pollution control equipment. Include information concerning fuel input, burners and combustion chamber dimensions.

See attachments

XXXXXXXXXXXXX

SEP 21 1976

Mr. Robert Hughes, Director
Environmental Affairs
East Kentucky Power Cooperative
P. O. Box 707
Winchester, Kentucky 40391

Dear Mr. Hughes:

This office has completed its review of your application for authority to construct electrical generating Unit #2 near Maysville, Kentucky. On the basis of this review, we have determined that operation of the proposed unit at the specified location will not cause or exacerbate a violation of the National Ambient Air Quality Standards or violate the Class II air quality increments specified in the EPA Regulations for Prevention of Significant Deterioration (PSD). Furthermore, we have determined that this unit will meet the Federal regulatory requirement under PSD that best available control technology (BACT) be used to limit emissions of sulfur dioxide and particulate matter.

A public notice regarding EPA's preliminary determination on the above application was published on April 27, 1976. After consideration of submitted comments, Authority to Construct a Stationary Source is hereby issued for the facility described above subject to the attached conditions, which are in accordance with the conditions detailed in the attached September 1, 1976, "Preconstruction Review and Final Determination for East Kentucky Power Cooperative Charleston Bottoms Generating Station #2 to be constructed near Maysville, Kentucky".

Please be advised that a violation of any condition issued as part of this approval, as well as any construction which proceeds at material variance with information submitted in your application, will be regarded as a violation of construction authority, and will be subject to enforcement action.

EXHIBIT K

Authority to construct shall take effect on the date of this letter. The complete analysis, including public comments, which justifies this approval has been fully documented for future reference, if necessary. Any questions concerning this approval may be directed to Winston Smith, Chief, Trends Analysis and Program Coordination Section (404/526-2864).

Sincerely yours,

/s/ John A. Little
Deputy Regional Administrator
Jack E. Ravan
Regional Administrator

Attachments

cc: Archie Lee
Winston Smith
John Eagles
Ray Gregory
Jesse Baskerville
John Smither

AHMD:JIEagles:kh:2864:9/10/76

List of Conditions of Approval

A. For Particulate Emissions from the Boiler:

1. The applicant must submit to EPA, within twenty working days after it becomes available, copies of all technical data pertaining to the selected control device, including guaranteed efficiency or emission rate, and major design parameters such as plate area, gas flow rate, and gas temperature. Although the type of control device which is described in general in the application has been determined by EPA to be adequate, EPA must review the final selected device in order to verify the emission limit stated in the application. EPA may, upon review of these data, disapprove the application if EPA determines the selected control device to be inadequate to meet the emission limit specified in this conditional approval. EPA must review and approve the selected control device before purchase of the device by the applicant. If a particulate control device has already been purchased, data on this device should be submitted within twenty working days of the date of approval.

2. Additionally, the applicant must comply with the following:

a. Within 60 days after achieving the maximum production rate at which the facility will be operated, but no later than 180 days after initial start-up the owner or operator shall conduct performance tests and furnish EPA a written report of the results of such performance tests.

b. Performance tests shall be conducted and data reduced in accordance with methods and procedures specified by EPA. Reference methods 1 through 5 as published in Appendix A of 40 CFR 60 will be used for particulate tests.

c. Performance tests shall be conducted under such conditions as EPA shall specify based on representative performance of the facility. The owner or operator shall make available to EPA such records as may be necessary to determine the conditions of the performance tests.

d. The owner or operator shall provide EPA 30 days prior notice of the performance test to afford the opportunity to have an observer present.

e. The owner or operator shall provide or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to the facility.

(2) Safe sampling platform(s).

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

(4) Utilities for sampling and testing equipment.

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

3. The source must meet an emission limit, as measured under part (2) as follows:

a. Particulate matter emitted to the atmosphere from the boiler shall not exceed 0.18 grams per million calories heat input (0.10 pound per million BTU).

b. Opacity of emissions from the boiler shall not exceed 20% except that a maximum of 40% opacity shall be permissible for not more than 2 minutes in any hour.

These emission limitations are identical to those required by Federal New Source Performance Standards, 40 CFR 60.

B. For Sulfur Dioxide Emissions from the Boiler:

1. The applicant must submit to EPA, within twenty working days after it becomes available, copies of all technical data pertaining to the selected control system, including a description of the operation of the system, guaranteed efficiency or emission rate, and major design parameters requested by EPA after initial review of the system. EPA may, upon review of these data, disapprove the application if EPA determines the selected control device or devices to be inadequate to meet the emission limits specified in this conditional approval. EPA must review and approve the selected control system before purchase of the system by the applicant. If a control system has already been purchased, data on this system should be submitted within twenty working days of the date of this approval.

2. Additionally, the applicant must comply with the following:

a. Within 60 days after achieving the maximum production rate at which the facility will be operated, but no later than

180 days after initial start-up the owner or operator shall conduct performance tests and furnish EPA a written report of the results of such performance tests.

b. Performance tests shall be conducted and data reduced in accordance with methods and procedures specified by EPA. Reference method 6 as published in Appendix A of 40 CFR 60 will be used for sulfur dioxide tests.

c. Performance tests shall be conducted under such conditions as EPA shall specify based on representative performance of the facility. The owner or operator shall make available to EPA such records as may be necessary to determine the conditions of the performance tests.

d. The owner or operator shall provide EPA 30 days prior notice of the performance test to afford the opportunity to have an observer present.

e. The owner or operator shall provide or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to the facility.

(2) Safe sampling platform(s).

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

(4) Utilities for sampling and testing equipment.

f. Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified by EPA. For the purpose of determining compliance with an emission limitation the arithmetic mean of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of force shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the approval of EPA, be determined using the arithmetic mean of the other two runs.

3. The source must meet an emission limit, as measured under part (2) as follows:

Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 2.2 grams per million calories heat input (1.2 pounds per million BTU).

The emission limitation is identical to that required by Federal New Source Performance Standards, 40 CFR 60.

C. Coal Characteristics:

Before approval can be granted by EPA for purchase of control devices under conditions A.1 and B.1 above, characteristics of the coal to be fired must be known. Therefore, before these approvals are granted, the applicant must submit to EPA details of coal characteristics used in bid specifications for boiler and control equipment, including expectant sulfur content, ash content, and heat content of the coal to be fired. This data will be used by EPA in its evaluation of the adequacy of the control devices. In addition, the applicant must submit to EPA before approval is granted to purchase control devices under A.1 and B.1 above, the following information.

1. Copies of contracts to purchase coal including expected sulfur content, ash content, and heat content of the coal, or

2. Other information showing that coal of the specified quality, or better, will be available to the applicant upon start-up of the boiler.

D. Stack Parameters:

The applicant must submit to EPA, within twenty working days after it becomes available, data on stack parameters for Unit #1 and Unit #2 that result from the selected control system(s), including exit gas temperature, exit gas velocity, stack diameter and stack height. EPA may, upon review of these data, disapprove the application if EPA determines that the air quality impact for the combination of Units 1 and 2 will be greater than that specified for Class II areas in the EPA Regulations for Prevention of Significant Air Quality Deterioration.

PRE-CONSTRUCTION REVIEW AND FINAL DETERMINATION FOR EAST KENTUCKY POWER COOPERATIVE CHARLESTON BOTTOMS GENERATING STATION UNIT #2 TO BE CONSTRUCTED NEAR MAYSVILLE, KENTUCKY

This review was performed by the U.S. Environmental Protection Agency in accordance with the EPA Regulations for Prevention of Significant Air Quality Deterioration

September 1, 1976

INTRODUCTION AND PRELIMINARY DETERMINATION

On December 5, 1974, the Environmental Protection Agency promulgated regulations for Prevention of Significant Air Quality Deterioration (PSD). These regulations were amended on June 12, 1975. Under these regulations, a source that is included in one of 19 source categories must be reviewed with regard to significant deterioration prior to construction. Authority for implementing these regulations in the State of Kentucky presently rests with the EPA. Therefore, sources wishing to construct in Kentucky must obtain approval from EPA as well as a permit from the State.

Under the PSD regulations a source must pass two criteria in order to be approved. The first criteria is that Best Available Control Technology (BACT) must be used on all emission points of sulfur oxides and particulate matter within the facility. The second criteria is that increases in ambient concentrations of SO_2 and particulates resulting from emissions from this source must not exceed certain increments. All areas are presently classified as Class II.

Allowable increments in ambient concentrations are as follows:

Pollutant	ug/m^3
Particulate Matter	
Annual Geometric Mean	10
24-Hour Maximum	30
Sulfur Dioxide	
Annual Arithmetic Mean	15
24-Hour Maximum	100
3-Hour Maximum	700

East Kentucky Power Cooperative wishes to construct a 526 MW power generating facility near Maysville, Kentucky, and has made application to the EPA for approval to construct Unit #2. The company has already commenced construction on Unit #1 at this site but this unit is not subject to review under the PSD regulations. Because a construction permit for Unit #1 was obtained prior to January 1, 1975; the increase in ambient concentrations of particulate matter (TSP) and sulfur dioxide (SO_2) from this source will not count against the allowable increment for a Class II area. The EPA has reviewed the materials submitted by East Kentucky Power Cooperative for Unit #2 and has made a final determination that in accordance with 40 CFR 52.21(d)(2)(ii), this construction will be approved with conditions. The conditions are necessary for the following reasons:

1. An emission limit is required as a condition of approval for each source under 40 CFR 51.21(d)(2)(ii).
2. From the data submitted in the application, EPA is unable to determine whether best available control technology (BACT) for control of particulate and sulfur dioxide emissions will be applied to the source. The following general statements can be made concerning BACT for power plants:
   a. BACT for particulates would consist of a high efficiency (greater than 99%) particulate removal device, usually an electrostatic precipitator (ESP).
   b. BACT for sulfur dioxide would consist of either low sulfur coal (less than 0.7%) or a flue gas desulfurization (FGD) system.

c. The maximum emissions of particulate and SO_2 which will be allowable are 0.1 lb/million BTU heat input and 1.2 lb/million BTU heat input, respectively. These values are fixed by the emission limitations specified in 40 CFR 60, New Source Performance Standards. Although the application states that a 99% efficient ESP and 0.66% sulfur coal are to be used (both are acceptable), EPA must determine, from specific plant and control device design data, and coal contracts, whether the boiler will in fact meet the stated emission rates. Since no design data is available for the control device, EPA cannot make this decision at the present time. Part of the conditions for approval to construct the plant, therefore, require the applicant to submit certain design and vendor guarantee information to EPA before purchase of any particulate removal devices, and to submit a copy of contracts for delivery of coal of the required sulfur content for a sufficient time to allow for installation of sulfur removal devices if coal supplies diminish.

The Following is a Listing of the Conditions of Approval:

1. For particulate emission from the boiler:

   a. The applicant must submit to EPA, within five working days after it becomes available, copies of all technical data pertaining to the selected control device, including formal bid from the vendor, guaranteed efficiency or emission rate, and major design parameters such as plate area (ESP) and air flow rate. Although the type of control device which is described in general in the application has been determined

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

a. Within 60 days after achieving the maximum production rate at which the facility will be operated, but no later than 180 days after initial startup the owner or operator shall conduct performance tests and furnish EPA a written report of the results of such performance tests.

b. Performance tests shall be conducted and data reduced in accordance with methods and procedures specified by EPA. Reference Methods 1 through 5 as published in Appendix A of 40 CFR 60 will be used for particulate tests. Reference Method 6 will be used for SO_2 tests.

c. Performance tests shall be conducted under such conditions as EPA shall specify based on representative performance of the facility. The owner or operator shall make available to EPA such records as may be necessary to determine the conditions of the performance tests.

d. The owner or operator shall provide EPA 30 days prior notice of the performance test to afford the opportunity to have an observer present.

e. The owner or operator shall provide or cause to be provided, performance testing facilities as follows:

   i. Sampling ports adequate for test methods applicable to the facility.

   ii. Safe sampling platform(s).

   iii. Safe access to sampling platform(s).

   iv. Utilities for sampling and testing equipment.

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

4. Coal Characteristics and Contracts:

Before approval can be granted by EPA for purchase of a control device under condition 1.a. above, characteristics of the coal to be fired must be known. Therefore, before these approvals are granted, the applicant must submit to EPA copies of contracts to purchase coal and expected sulfur content, ash content, and heat content of the coal to be fired. These data will be used by EPA in its evaluation of the adequacy of the control devices. Also, the applicant must demonstrate the ability to acquire a low sulfur coal supply of sufficient length to enable the installation of sulfur removal equipment if the supplies of low sulfur coal should be discontinued. Therefore, the coal contracts must be for a period of at least three (3) years from the date of startup of the boiler.

Beginning one month after final conditional construction approval from EPA and ending when on-site construction of the source is initiated, the applicant shall submit to EPA a monthly status report briefly outlining progress made on engineering design and purchase of major pieces of equipment, including control equipment.

by EPA to be adequate, EPA must review the final selected device in order to verify the emission limits stated in the application. EPA may, upon review of these data, disapprove the application if EPA determines the selected control device to be inadequate to meet the emission limits specified in this conditional approval.

b. The source must meet an emission limit, as measured under part (3) as follows:

   i. Particulate matter emitted to the atmosphere from the boiler shall not exceed 0.18 gram per million calories heat input (0.10 pound per million BTU).

   ii. Opacity of emission from the boiler shall not exceed 20 percent except that a maximum of 40 percent opacity shall be permissible for not more than 2 minutes in any hour.

These emission limitations are identical to these required by Federal New Source Performance Standards, 40 CFR 60.

2. <u>For sulfur dioxide from the boiler:</u>

The source must meet an emission limit, as measured under part (3), as follows:

Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 2.2 grams per million calories heat input (1.2 pounds per million BTU).

This emission limitation is identical to that required by Federal New Source Performance Standards, 40 CFR 60.

FINAL DETERMINATION

The preliminary determination was made available at the following locations:

U.S. Environmental Protection Agency
1421 Peachtree Street, N.E.
Atlanta, Georgia 30309

Division of Air Pollution
Kentucky Department for Natural Resources
and Environmental Protection
West Frankfort Office Complex
U.S. 127 South
Frankfort, Kentucky 40601

Department for Natural Resources
Division of Air Pollution
Ashland Regional Office
2108 29th Street
Ashland, Kentucky 41101

Mayor's Office
Municipal Building
3rd and Bridge Street
Maysville, Kentucky 41056

Comments were requested in public notices in the Maysville Ledger-Independent and the Ashland Daily Independent. Additionally a hearing was held in Maysville, Kentucky, on August 3, 1976, and comments were received at and following the hearing.

The air-related comments addressed two issues. One is the excessive TSP emissions from the Stuart plant. That is addressed elsewhere in this package.

The second is the power plant growth along the Ohio River. The desire for an area wide study was stated, along with the desire for moratorium on power plant construction until the completion of such a study. The regulations for prevention of significant deterioration do not give this office the authority to take either action, so the second issue is not relevant.

Since no information was received which would alter the PSD analysis done in the Preliminary Determination, the Final Determination is that construction of unit #2 is allowable, with conditions.

Air Quality Analysis

Introduction

The purpose of this section is to present the results of a diffusion analysis, using EPA's air quality models, to predict the maximum concentrations for suspended particulates (TSP) and sulfur dioxide (SO_2) for various averaging periods. The methodology and the results of the analysis are presented in the next section of this report. Based on these results, the following conclusions may be drawn for installation of Unit #2.

> The impact of Unit #2 operation will be in compliance with EPA's Regulations for the Prevention of Significant Deterioration promulgated in the Federal Register, December 5, 1974.

> The ground-level concentrations of TSP and SO_2 due solely to the operation of the proposed unit will not contravene any applicable state or federal ambient air quality standard.

Methodology and Results

The impact of the proposed unit upon local ambient contaminant levels was evaluated by means of mathematical models which simulate the processes of transport and diffusion of stack effluents in the atmosphere. The models employed for this purpose are Gaussion Plume models developed by the Meteorological Laboratory of the Environmental Protection Agency. Inputs include physical dimensions and emission characteristics of the source, as well as hourly values of those meteorological parameters affecting plume behavior. The emission rate used for modeling the new unit were emissions which are allowable under New Source Performance Standards. Ground level concentrations of TSP and SO_2 attributable to operation of Unit #2 were computed for one-hour, 24-hour, and annual averaging periods. The output obtained from application of the models consists of hourly, daily, and annual average concentrations at each designated "receptor" location.

Table I presents the input parameters to the models for the single emission point of the proposed unit, as well as stack parameters for sources located in the area.

The models used and brief summaries of each model are given below:

PTMAX - A single source model which calculates the maximum concentration and downwind distance to point of maximum concentration as a function of stability class and a given set of wind speed categories.

CRS - A point source model which is designed to calculate maximum one-hour, 24-hour, and annual average concentration at a specified set of receptors for a full year of actual hourly meteorological data.

PTMTP-W - A multiple source model which calculates hourly concentrations and the average concentration for several hours as a function of specified meteorological conditions at specified receptors.

Terrain Model - A multiple source model which calculates the annual arithmetic average concentration from regional source emission and meteorological data in areas of rough terrain.

When utilizing the PTMTP-W and Terrain Model, all major sources of emissions in the surrounding area are included to determine both the incremental impact of Unit #2 and the total air quality impact from all sources in the area. In the case of Spurlock's Unit #2, emissions from Unit #1 and the Stuart facility were included in this analysis.

To insure that Unit #2 would not cause ambient air quality violations, all the major sources of emissions in the immediate area were modeled. As stated earlier, Spurlock's Unit #1 and the Stuart facility were the only major sources included in this analysis. Modeling all the units at allowable emissions, no air quality violations were predicted. The maximum 24-hour concentration of sulfur dioxide was 45.6 ug/m^3 and occurred approximately 3.2 km. from the plant using a terrain adjustment factor of 79.0 meters.

The maximum 24-hour concentration of TSP was 2.7 ug/m^3 and occurred 3.2 km. from the plant.

In doing this analysis, the following assumptions were made concerning the Stuart plant. For TSP, the maximum allowable emission rates under the Ohio implementation plan were used. Although this plant is not yet in compliance with particulate emission limits, it is expected to achieve compliance this fall. Spurlock #2 will not begin operation for several years, so its emissions will not be additive to the excessive TSP recently emitted by Stuart.

For SO_2, there is no Federally approved emission limitation appropriate to Stuart, so it was modeled at existing reates. However, this does not in any way affect the significant deterioration permitting of Spurlock #2, and since the combined impact from both plants was 45 ug/m^3 compared to the standard of 365 (for 24 hours), even a sizeable increase in Stuart's SO_2 emissions would not interfere with standards.

There is no expected date for setting SO_2 emission limits on Stuart.

After using PTMAX to determine the general area where the maximum concentration would occur for Unit #2, CRS was run to find the "worst day" meteorological conditions at these receptors. With those meteorological conditions and the PTMTP-W program, the impact of Unit #2 was evaluated.

Close examination of the modeling showed that Unit #2 meets both the TSP and SO_2 short-term air quality increments. The maximum 24-hour concentration of TSP and SO_2 were 2.1 ug/m^3 and 25.0 ug/m^3 respectively, and occurred approximately 1.2 km. from the unit where the terrain is approximately 80 meters higher than the stack base elevation. The maximum three-hour concentration of SO_2 was 127.0 ug/m^3 and occurred at the same point as the 24-hour maximum concentration.

The impact of Unit #2 on annual air quality was then evaluated using theTerrain Model which employes Briggs plume rise equations. The results of this analysis showed that the maximum annual concentration for TSP and SO_2 would be less than 1.0 ug/m^3 respectively, at a distance of 10.0 km.

Below is a summary of the air quality impact of the proposed unit.

Pollutant	Allowed ug/m3	Unit #2 ug/m3
Particulate Matter		
Annual Geometric Mean	10	<1.0
24-Hour Maximum	30	2.1
Sulfur Dioxide		
Annual Arithmetic Mean	15	<1.0
24-Hour Maximum	100	25.0
3-Hour Maximum	700	127.0

TABLE 1

STACK PARAMETERS OF EMISSION POINTS MODELED

Unit	Stack Height (m)	Stack Diameter(m)	Exit Velocity(m/sec)	Temp (°k)	Emissions (g SO_2	TS
Spurlock 1	245.5	4.57	28.53	417.0	1333.87	[illegible]
Spurlock 2	245.5	6.10	27.71	414.0	774.82	64
Stuart 1	243.8	6.04	30.78	389.0	2084.40	286
Stuart 2	243.8	6.04	30.78	389.0	2084.40	286
Stuart 3	243.8	6.04	30.78	389.0	2084.40	286
Stuart 4	243.8	6.04	30.78	389.0	2084.40	286

XXXXXXXXXXX

East Kentucky Power Cooperative

"A Rural Electric Cooperative Corporation"

P. O. Box 707 · Lexington Road · Winchester, Kentucky 40391 · 606-744-4812

January 23, 1976

RECEIVED

Mr. Frank L. Stanonis, Commissioner
Bureau of Environmental Quality
Department for Natural Resources and
Environmental Protection
Capital Plaza Tower
Frankfort, Kentucky 40601

Dear Mr. Stanonis:

Subject: Hugh L. Spurlock Power Station - Unit _

In accordance with KRS Chapter 224 and KRS Chapter 278, East Kentucky Power Cooperative, Inc. hereby requests the Department for Natural Resources and Environmental Protection, Bureau of Environmental Quality for the permits appropriate to allow the construction of subject electric power generating unit.

Enclosed find:

1. Application for Permit - Division of Water Quality

2. Permit Application for Air Contaminant Source
Division of Air Pollution

Relative to No. 1 above, this construction does constitute the addition of a unit, therefore, the basic plans and specifications should be on file with the Division of Water Quality. The attached Water System General Diagram and the Environmental Analysis - Spurlock Station Unit 2 should adequately supply the information relative to size and constituents of the added load. Subject unit is projected to go on line in 1980.

Relative to No. 2 above, the application and attachments should be detailed enough to allow a complete assessment of the impact the source will have on the ambient air.

The information contained in the permit applications and attachments should also be sufficient to allow the Department For Natural Resources

(continued)

EXHIBIT J

and Environmental Protection to make its report to the Public Service Commission pursuant to KRS 278.025. We respectfully request that this action be done in as short a time span as possible.

In order to facilitate your records and prevent any possible confusion, please be advised that subject power station has been referenced by several other designations at various stages of planning and construction. These designations include The Ohio River Generating Station, Maysville Power Plant, and Charleston Bottoms Power Station. Please correct your files and records accordingly.

An Environmental Impact Statement is being prepared relative to this project and will be submitted to you via the normal procedure within a few weeks.

If you have questions, please call.

Sincerely,

EAST KENTUCKY POWER COOPERATIVE, INC.

WE Gill

William E. Gill, Director
Environmental Affairs

WEG:sh

Enclosures

Eastern District of Kentucky
FILED

JAN 17 2006

AT LEXINGTON
LESLIE G WHITMER
CLERK U S DISTRICT COURT

UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF KENTUCKY
LEXINGTON DIVISION

CIVIL ACTION NO. 04-34 - KSF

UNITED STATES OF AMERICA PLAINTIFF,

VS.

EAST KENTUCKY POWER COOPERATIVE, INC. DEFENDANT.

* * * * * * * * * * *

PLAINTIFF UNITED STATES' MEMORANDUM IN SUPPORT OF ITS FOURTH MOTION FOR SUMMARY JUDGMENT:

EKPC'S ACTIONS IN CONNECTION WITH THE INLAND STEAM SUPPLY PROJECT INVOLVED PHYSICAL AND OPERATIONAL CHANGES WITHIN THE MEANING OF THE APPLICABLE <u>PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS</u>

EXHIBIT L

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TABLE OF AUTHORITIES

FEDERAL CASES

FEDERAL STATUTES

FEDERAL REGULATIONS

STATE REGULATIONS

See Wisconsin Elec. Power Co. v. Reilly, 893 F.2d 901, 905, 909 (7th Cir. 1990) *(WEPCo)*; *Alabama Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979). The Clear Air Act defines "modification" as:

> any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

42 U.S.C. §§ 7479(2)(C), 7411(a)(4).

In order to determine whether a planned activity is a "modification," the statute thus requires as a first step an evaluation of whether the project contemplates a "physical change . . . or change in the method of operation." *Id.* Neither the Act nor EPA's PSD regulations further define "physical change" or "change in the method of operation." However, EPA's PSD regulations provide that certain kinds of activities, such as "[r]outine maintenance, repair and replacement" and certain increases "in the hours of operation or in the production rate" are deemed not to be physical or operational changes. *See, e.g.*, 40 C.F.R. § 51.166(b)(2)(iii)(a), (f); 45 Fed. Reg. 52676, 52698, 52730 (Aug. 7, 1980) (Appendix A).[4]

EPA has explained that the exclusions applicable at the time of the projects at issue in this case are intended to be construed in a "common-sense" fashion:

> The EPA has always recognized that the definition of physical or operational change . . . could, standing alone, encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky

[4] In 2003, EPA promulgated a new "Equipment Replacement Provision" that would apply prospectively only, and would provide that the replacement of components of a process unit with identical or "functionally equivalent" components will not be deemed a "modification" if (1) there is no change in the basic design parameters of the unit; (2) applicable emission or operation limits are not exceeded; and (3) the cost of the replacement activity does not exceed twenty percent of the replacement value of the process unit. 68 Fed. Reg. 61248, 61252 (Oct. 27, 2003). The new rule was challenged by environmental organizations and certain states, and is currently not in effect because it has been stayed by the D.C. Circuit. 70 Fed. Reg. 33838, 33847 (June 10, 2005). Thus, both because of its prospective-only application and its current status, this rule is not at issue in this case.

> pipe, or a change in the way that pipe is utilized). However, EPA has always recognized that Congress obviously did not intend to make every activity at a source subject to new source requirements.
>
> As a result, EPA has defined 'modification' . . . to include common-sense exclusions from the 'physical or operational change' component of the definition.

57 Fed. Reg. 32314, 32316 (July 21, 1992) (Appendix B). EPA has further characterized the hours of operation/production rate exclusion as one of a "narrow and limited set of exclusions . . . only to allow for routine changes in the normal course of business . . . ." Letter from David Howekamp, EPA Region IX Air Management Division Director, to Robert Connery, Holland and Hart, at 5-6 (Nov. 6, 1987) (Cyprus Casa Grande Applicability Determination) (Ex. 1).

EPA regulations do not define "routine maintenance, repair, and replacement," but EPA's authoritative interpretation of the routine maintenance exclusion applicable in this case holds that it is a "very narrow exclusion" and that its application calls for a multi-factor, "common-sense," "case-by-case" determination taking into account the "nature, extent, purpose, frequency, and cost" of the activity. Memorandum from Don Clay, Acting Assistant Administrator of EPA, to David Kee, EPA (Sept. 9, 1988) (Clay Memo) (Ex. 2); *see United States v. Southern Ind. Gas & Elec. Co. (SIGECO I)*, 2003 WL 446280, at * 2 (S.D. Ind. Feb. 18, 2003); *United States v. Southern Ind. Gas & Elec. Co. (SIGECO II)*, 245 F. Supp. 2d 994, 1014 (S.D. Ind. 2003).

Consistent with its plain language as a simple exclusion from the definition of operational "change," EPA's authoritative interpretation of the production rate/hours of operation exclusion similarly holds that it is narrowly construed, so as to allow sources to simply vary production rate and operating hours as part of normal operations within otherwise applicable limits. Otherwise, even normal and lawful variations could potentially be considered an operational change.

However, EPA has explained that the exclusion does not apply when increased hours or production rates are otherwise unlawful, nor does it apply when such increases are themselves caused by or associated with other physical or operational changes:

> Although a source may vary its hours of operation or production as part of its everyday operations, an increase in emissions attributable to an increase in hours of operation or production rate which is the result of a construction-related activity is not excluded from review.

57 Fed. Reg. at 32328; *see also* 45 Fed. Reg. at 52704 (exclusion allows sources to "take advantage of favorable market conditions"); *WEPCO,* 893 F.2d at 916 n. 11 (exclusion "was provided to allow facilities to take advantage of fluctuating market conditions, not construction or modification activity"); *Puerto Rican Cement Co. v. EPA*, 889 F.2d 292, 297-98 (1st Cir. 1989) (upholding EPA interpretation of exclusion as allowing sources "simply to increase their output" through "*increased use of existing facilities*" as opposed to increases resulting from construction or modification activity).

This exclusion thus applies only to "simple, "stand-alone" changes that do not otherwise violate the law and which are not caused by some other physical or operational change that allows for increased hours or production rates:

> [T]his exclusion is intended to allow a company to lawfully increase emissions through a simple change in hours or rate of operation up to its potential to emit (unless already subject to any federally enforceable limit) without having to obtain a PSD permit. Thus, emissions increases . . . associated with increased operations would not, standing alone, subject [a source] to PSD requirements. However, . . . the exclusion for increases in hours of operation or production rate does not take the project beyond the reach of PSD coverage if those increases do not stand alone but rather are associated with non-excluded physical or operational changes.

Clay Memo, at 6-7 (Ex. 2); *see* Letter from Lee Thomas, EPA Administrator, to John Boston, WEPCo, at 4-5 (Oct. 14, 1988) (1988 Thomas Letter) (Ex. 3) (holding that the exclusion is intended to allow increased hours and production in response to "routine fluctuations in the business cycle" and *not* in response to increases "stemming from significant new capital investment."); *In re Monroe Elec. Generating Plant Proposed Operating Permit*, Petition No. 6-99-2, at 13 (U.S. EPA 1999) (Monroe Electric Determination) (Ex. 4) ("The purpose of this 'increase in hours' exception was to avoid undue disruption by allowing routine increases in production during the normal course of business in order to respond to market conditions."); Cyprus Casa Grande Determination, (Ex. 1) at 3, 6 (exclusion intended to apply to "routine change in the hours or rate of operation").

Following EPA's promulgation of its 1980 PSD regulations, Kentucky submitted its own PSD regulations to EPA for approval and inclusion in the Kentucky SIP at 401 KAR 51:017 (Appendix C).[5] EPA approved Kentucky's SIP provisions for PSD on September 1, 1989, after determining that Kentucky's PSD regulations met EPA's minimum requirements set forth at 40 C.F.R. § 51.166 for approval of state PSD regulations. *See* 54 Fed. Reg. at 36307 (Appendix D). For enforcement purposes, however, EPA explicitly retained in the SIP its own pre-existing PSD regulations promulgated at 40 C.F.R. § 52.21, as they apply to sources (such as Spurlock Unit 2) that originally obtained PSD permits directly from EPA under these regulations. *See* 54 Fed. Reg. at 36309. Thus, the applicable language governing the routine maintenance and production

[5] EPA initially promulgated PSD regulations in December 1974 at 40 C.F.R. § 52.21, which applied to construction which, like that at Spurlock Unit 2, commenced on or after June 1, 1975. *See* 39 Fed. Reg. 42510, 42514, 42515 (Dec. 5, 1974). When Congress enacted the statutory PSD program in 1977, it significantly expanded and strengthened PSD requirements and broadened the scope of the program under which sources such as Spurlock Unit 2 had been originally permitted. *New York v. EPA*, 413 F.3d 3, 12, 19-20 (D.C. Cir. 2005); *Alabama Power*, 636 F.2d at 349-50. In 1980, EPA thus promulgated regulations setting forth the minimum requirements for EPA-approved PSD programs contained in SIPs at 40 C.F.R. § 51.24 (later redesignated as 40 C.F.R. § 51.166 (1987)). *See* 45 Fed. Reg. at 52729. The regulatory PSD requirements for sources in states without approved PSD programs in their SIPS were amended at 40 C.F.R. § 52.21. *See id.* at 52735. Prior to 1980 EPA directly issued PSD permits in Kentucky under 40 C.F.R. § 52.21. *See* 54 Fed. Reg. 36307, 36309 (Sept. 1, 1989).

rate/hours of operation exclusions as applied to the modifications alleged in this case states in material part:

> A physical change or change in the method of operation shall not include:
>
> 1. Routine maintenance, repair and replacement;
> ***
> 5. An increase in the hours of operation or in the production rate, unless the change would be prohibited after January 6, 1975 pursuant to 40 CFR 52.21 . . . or under 401 KAR 50:035. . . .[6]

401 Ky. Admin. Reg. 51:017 Section 1(2)(b) (1992) (Appendix C).

STATEMENT OF MATERIAL FACTS NOT IN DISPUTE

1. The Spurlock generating Station is located in Mason County, Kentucky. At times relevant to this case, the station had two steam-electric generating stations, including Spurlock Unit 2, which went into commercial operation in March 1981. EKPC Feb. 25, 2005 Responses to Interrogatories (Ex. 5), Page 11.

A. Spurlock Unit 2's Original Boiler and Turbine Design Capacity.

2. The boiler on Unit 2 was designed and manufactured by Combustion Engineering. It originally had a maximum continuous rating (MCR) of 3,800,000 pounds of steam per hour at 1005°F. The guaranteed steam load was 3,600,000 pounds of steam per hour. EKPC Feb. 25, 2005 Responses to Interrogatories (Ex. 5), Page 14-15; EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 91; Combustion Engineering Instruction Manual (Ex. 7), at S-0035939, S-0035942, S-0035945; July 1, 1976 Design Summary Letter (Ex. 8), at EKPC_ABB0000461 - EKPC_ABB0000465.

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[6] At the time of the alleged modifications, 401 KAR 50:035 set forth Kentucky's separate SIP provisions governing construction and operation of all air pollution sources, even those that did not trigger PSD requirements (Appendix E).

3. Based on both design and testing, the Spurlock Unit 2 boiler required a heat input rate of 5,120 mmBTU per hour to operate at 3,800,000 pounds per hour of steam. November 2005 Joint Stipulation Concerning Plaintiff's Exhibit 173 with attachment (Ex. 9).

4. The original design data for Spurlock Unit 2 indicates that 454,200 pounds per hour of coal with a heating value of 10,648 BTU per pound, was assumed to be required to produce 3,600,000 pounds per hour of steam. EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 94. The boiler heat input rate required to produce this much steam using such coal is 454,200 pounds of coal times 10,648 BTU per pound equals 4,836,321,600 BTU per hour, or approximately 4,836 mmBTU per hour.

5. The steam turbine at Spurlock Unit 2 was originally designed to handle 3,580,250 pounds per hour of steam with the steam inlet valves wide open. EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 90.

B. EKPC Previously Applied for a PSD Permit Upon Initial Construction of Spurlock Unit 2, and Identified the Rated Heat Input Capacity of the Unit as 4850 mmBTU per Hour, With a Short-Term Peak Heat Input of 5120 mmBTU Per Hour.

6. Spurlock Unit 2 was constructed in the mid-1970s, and prior to beginning construction on the unit, EKPC was required to apply for and obtain approval from EPA under EPA's 1974 PSD regulations set forth at 40 C.F.R § 52.21. *See supra* footnote 5.

7. As part of the PSD review process, EKPC was required to submit to EPA a PSD application, including an "Air Pollutant Emissions Report." The instructions for completing the Air Pollutant Emissions Report informed EKPC that the required information would be used to determine the impact of the unit on air quality. Therefore:

> Data requested in this report should be representative of anticipated operating conditions. Any changes in this data should be reported immediately to the EPA Regional Office, as this may affect the air quality or emissions analysis. (Such as new fuel supplies, process modifications, change in emission rates, etc.).

Instructions for Completing the Air Pollutant Emissions Report (Ex. 10), at H-0074403; EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 65.

8. As part of its PSD application, EKPC submitted its Air Pollution Emissions Report for Spurlock Unit 2 in March 1976. March 19, 1976 Letter from Ronald Rainson with enclosures (Ex. 11); Jan. 23, 2003 Letter from Jay Holloway with enclosures (Ex. 12); January 10, 2005 Declaration of Mary Hawkins (Ex. 13).

9. EKPC's PSD application identified the rated capacity of Spurlock Unit 2 as 4,850 mmBTU per hour. EKPC calculated this heat input to result in 526 megawatts (MW) of power generation. March 19, 1976 Air Pollutant Emissions Report (Ex. 11), at KDAQ0000003.

10. Although EKPC indicated in a footnote that Spurlock Unit 2 was capable of a short-term peak heat input rate of 5,120 mmBTU per hour, when asked to estimate the unit's total annual emissions, EKPC did so using the unit's rated capacity of 4,850 mmBTU per hour. March 19, 1976 Air Pollutant Emissions Report (Ex. 11), at KDAQ0000021.

11. On September 21, 1976, EPA issued formal permission for EKPC to construct Spurlock Unit 2 under the 1974 PSD regulations. September 21, 1976 Letter from John Little (Ex. 14); September 1, 1976 Pre-Construction Review and Final Determination (Ex. 15).

12. For purposes of estimating annual emissions of sulfur dioxide (SO_2) from Spurlock Unit 2 to determine compliance with PSD requirements, EPA modeled the unit at a boiler heat input of 4,850 mmBTU per hour, which corresponded to the rated heat input capacity identified

by EKPC in its PSD application. EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 67; Dep. of Kenneth Weiss (November 15, 2005) (Ex. 16), at 25.

13. For purposes of estimating short-term emissions of SO_2 from Spurlock Unit 2 to determine compliance with PSD requirements, EPA also modeled Spurlock Unit 2 at a short-term heat input of 5,120 mmBTU per hour, which corresponded to the short-term peak heat input rate identified by EKPC in its PSD application. September 1, 1976 Pre-Construction Review and Final Determination (Ex. 15), at Table 1; Dep. of Kenneth Weiss (November 15, 2005)(Ex. 16), at 33-34, 175-176.

14. EKPC indicated that Spurlock Unit 2 would burn coal containing 1.2 pounds of SO_2 per mmBTU in information submitted as part of its PSD application, and EPA's subsequent Authority to Construct permit allowed Spurlock Unit 2 to burn coal containing 1.2 pounds of SO_2 per mmBTU. March 19, 1976 Letter from Ronald Rainson with enclosures (Ex. 11), at KDAQ0000021; September 1, 1976 Pre-Construction Review and Final Determination (Ex. 15), at EPA4ENF018165.

15. Assuming a rated heat input of 4,850 mmBTU per hour, this equates to approximately 733 grams per second of SO_2. At a heat input rate of 5,120 mmBTU per hour, this equates to approximately 774 grams per second of SO_2. Dep. of Kenneth Weiss (November 15, 2005) (Ex. 16), at 25, 33-34, 175-176.

16. When it approved EKPC's application to construct Spurlock Unit 2, EPA specifically stated that the Authority to Construct was based on the information submitted in EKPC's PSD application, and advised EKPC that subsequent construction which proceeded in material

variance with the information in its application would be subject to enforcement action.

September 21, 1976 Letter from John Little (Ex. 14), at 1.

17. EPA subsequently reiterated this warning to EKPC:

> A conditional approval such as this to construct a new source under PSD regulations carries with it an obligation, on the part of the applicant, to maintain contact with the approving regulatory agency and to keep that agency informed of any changes contemplated in the proposed source. . . . *Any change from your application must be reviewed to ensure compliance with the PSD requirements, e.g., BACT and applicable air quality increments.*

March 13, 1978 Letter from G.T. Helms (Ex. 17), at 2 (italics added; underline in original).

C. EKPC Obtained State Construction and Operating Permits for Spurlock Unit 2 Based on a Rated Heat Input Capacity of 4850 mmBTU per Hour.

18. In its separate January 23, 1976 application to the state of Kentucky's Division of Air Pollution Control[7] for a "permit to construct and operate," EKPC indicated that the rated capacity of Spurlock Unit 2 was approximately 4,850 mmBTU per hour, and that the only purpose of the unit was "power-electric generation." January 23, 1976 Letter from William Gill with enclosures (Ex. 18), at EPA4ENF018180, EPA4ENF018182.

19. The Kentucky Division of Air Pollution Control also performed its own analysis of expected emissions from Spurlock Unit 2 for purposes of demonstrating compliance with the NAAQS. Tr. of April 3, 1976 Joint Public Hearing (Ex. 19), at KY-0000006.

20. For this analysis, the Kentucky Division of Air Pollution Control indicated that it had assumed that Spurlock Unit 2 would operate at its rated capacity of 4,850 mmBTU per hour. Tr.

[7] The Kentucky Division of Air Pollution Control was a predecessor to the Kentucky Division for Air Quality (KDAQ).

of April 3, 1976 Joint Public Hearing (Ex. 19), at KY-0000005; EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 66.

21. The state of Kentucky subsequently issued its own state construction permit for Spurlock Unit 2 in December 1976. The permit advised that "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 of Air Pollution." December 2, 1976 Construction Permit (Ex. 20).

22. EKPC thereafter applied for a state operating permit for Spurlock Unit 2 pursuant to 401 Ky. Admin Reg. 50:035. EKPC reiterated that the rated capacity of Spurlock Unit 2 was 4,850 mmBTU per hour. May 18, 1982 Letter from Robert Hughes with enclosure (Ex. 21).

23. The Kentucky Division of Air Pollution Control issued an operating permit covering Spurlock Unit 2 in November 1982, which was subsequently amended on October 7, 1983. November 10, 1982 Operating Permit (Ex. 22); October 7, 1983 Operating Permit (Ex. 23).

24. The state operating permit stated that it was "subject to all conditions and operating limitations contained" in the permit. One of these explicit "conditions" was that Spurlock Unit 2 be operated at "4,850 mmBtu/hr maximum heat input." The permit advised that "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 of Air Pollution Control." November 10, 1982 Operating Permit (Ex. 22), at EKPC R16-000421; October 7, 1983 Operating Permit (Ex. 23), at EKPC R16-000424.

D. Subsequent Reliance on Spurlock Unit 2's Rated Capacity of 4850 mmBTU Per Hour.

25. In February 1984, Kentucky Power Co. (an unrelated public utility) submitted a PSD permit application for construction of a new coal-fired generating unit in Lewis County, Kentucky. Feb. 8, 1984 Letter from Robert Matthews enclosing PSD Application (Ex. 24).

26. The PSD permit application modeled the contribution of Spurlock Unit 2 to air quality based on an SO_2 emissions rate of approximately 734 grams per second. Feb. 8, 1984 Letter from Robert Matthews enclosing PSD Application (Ex. 24), at A41296006201110043, 082, 107.

27. At Spurlock Unit 2's permitted coal sulfur content of 1.2 pounds of SO_2 per mmBTU, this emissions rate equates to Spurlock Unit 2's rated capacity of 4,850 mmBTU per hour. *See* SOF ¶¶ 14, 15.

28. In March 1986, the Cincinnati Gas & Electric Company, the Columbus & Southern Ohio Electric Co., and the Dayton Power & Light Co. submitted a PSD permit application for construction of a new coal-fired generating unit at the Zimmer Power Station, which was also to be located in the vicinity of Spurlock Unit 2. March 1986 Air Quality Analyses in Support of a PSD Permit for Construction of the Zimmer Power Station (Ex. 25).

29. The Zimmer PSD permit application modeled the contribution of Spurlock Unit 2 to air quality based on an SO_2 emissions rate of approximately 733 grams per second. March 1986 Air Quality Analyses in Support of a PSD Permit for Construction of the Zimmer Power Station (Ex. 25), at C4129000170010473, C4129000170010518.

30. In September 1986, updated PSD modeling was prepared for EKPC analyzing the impact of Spurlock Unit 2 on ambient air quality to comply with recently enacted "Good Engineering Practice" stack height regulations. Good Engineering Stack Height Modeling of EKPC Units 1 and 2 (Ex. 26).

31. For purposes of this modeling, EKPC's contractor assumed that Spurlock Unit 2 would have an SO_2 emissions rate of approximately 733 grams per second. Good Engineering Stack Height Modeling of EKPC Units 1 and 2 (Ex. 26), at C-0118665, C-0118686, C-0118698, C-0118723, C-0118753. At Spurlock Unit 2's permitted coal sulfur content of 1.2 pounds of SO_2 per mmBTU, this emissions rate equates to Spurlock Unit 2's rated capacity of 4,850 mmBTU per hour. *See* SOF ¶¶ 14, 15.

32. Since at least 1985, EKPC's reports to the Kentucky Emissions Inventory System have indicated that Spurlock Unit 2 has an annual heat input capacity of 4,850 mmBTU per hour. EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 68.

33. EKPC recently applied for PSD permits for new coal-fired generating units at the Spurlock Plant. PSD modeling for Spurlock Unit 2 was again based on a heat input capacity of 4,850 mmBTU per hour. Dep. of Robert Hughes (February 18, 2005) (Ex. 27), at 218-19; EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 72.

E. Planning for the Spurlock Steam Supply Project.

34. In 1989, EKPC's Board of Directors authorized a "Steam Supply Alternatives Investigation" to evaluate whether EKPC could supply approximately 300,000 pounds per hour of steam from the Spurlock Plant to an adjacent box manufacturing facility to be constructed by

the Inland Container Corporation (Inland). June 12, 1989 Board of Directors Meeting Minutes (Ex. 28).

35. EKPC's Board of Directors authorized the Inland Steam Supply Project on October 9, 1990. A contract with Inland was signed on November 12, 1990. EKPC Feb. 25, 2005 Responses to Interrogatories (Ex. 5), Page 22. Under the Agreement, EKPC would own, operate, and maintain all facilities and equipment necessary for supplying steam to Inland, while Inland would pay a monthly facilities charge designed to reimburse EKPC for construction costs. Project Documents (Ex. 29), at S-0083458, 83490, 83501, 83506.

36. EKPC retained the consulting and engineering firm of Black and Veatch to perform the "Steam Supply Alternatives Investigation." October 10, 1989 Letter from Gary Crawford (Ex. 30).

37. Black and Veatch issued a final report discussing various options for supplying steam to Inland, and concluded, *inter alia*, that NSPS and PSD would not apply to the project provided that the heat input rate for Spurlock Unit 2 did not exceed 4,850 mmBTU per hour, the value contained in the existing air permit for Spurlock Unit 2. December 15, 1989 Steam Supply Alternatives Investigation (Ex. 31), at 2-5, 7-7 to 7-8.

38. After receiving the Black and Veatch report, EKPC hired Black and Veatch and ABB-Combustion Engineering, the original boiler manufacturer, to undertake various detailed engineering studies to evaluate the effects of supplying steam to Inland from Spurlock Unit 2. In an August 31, 1990 report, Black and Veatch discussed various designs for a reboiler system to generate and supply 300,000 pounds per hour of steam to Inland. The reboiler system would require addition of a large shell and tube heat exchanger to the Spurlock plant, with steam from

the Spurlock plant providing the energy to heat feedwater in the reboilers, thereby creating new steam to send to Inland. August 31, 1990 Black and Veatch Report - Reboiler (Ex. 32), at S-0012041, 12049; October 2, 1990 Letter to Gary Crawford, EKPC with enclosures (Ex. 33), at S-0016479.

F. EKPC Expected Heat Input Increases Associated with the Inland Steam Supply Project Above 5120 mmBTU per Hour.

39. EKPC prepared heat input calculations that indicated that supplying 300,000 pounds per hour of steam to Inland would require an additional 432 mmBTU per hour of heat input from Spurlock Unit 2. February 19, 1992 Memo to Sam Holloway with enclosures (Ex. 34), at H-0045696.

40. Black and Veatch prepared a July 25, 1991 Reboiler Supply Study to evaluate the effects of supplying steam to Inland using a reboiler supply system. The 1991 Reboiler Supply Study indicated that EKPC would expect increase the heat input rate of Spurlock Unit 2 to levels greater than 5,120 mmBTU per hour in connection with the Inland Steam Supply Project. The study indicated that the heat input rate of Spurlock Unit 2 could reach 5,197 mmBTU per hour when supplying steam to Inland. August 20, 1991 Memo from Hubert Smith enclosing July 25, 1991 Reboiler Supply Study (Ex. 35), at C-0109081; EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 79.

41. A follow-up "Auxiliary Steam Flow Study" was prepared by ABB-Combustion Engineering to formally evaluate the operational effects of supplying steam to Inland from Spurlock Unit 2. March 17, 1992 Memo from Mark Paluta enclosing March 13, 1992 Auxiliary Steam Flow Study (Ex. 36).

42. The study assumed that the Spurlock Unit 2 turbine could accept a maximum of 3,650,000 pounds per hour of steam at rated conditions. Compared to the Spurlock Unit 2 boiler's MCR of 3,800,000 pounds per hour of steam, this left only 150,000 pounds of steam available to provide to Inland. As requested, the Auxiliary Steam Flow Study also evaluated whether Spurlock Unit 2 could be "uprated" to produce additional steam, up to 3,950,000 pounds per hour, so as to still be able to provide the total requirements of 300,000 pounds per hour of steam to Inland while maintaining full turbine capacity of 3,650,000 pounds per hour of steam. March 17, 1992 Memo from Mark Paluta enclosing March 13, 1992 Auxiliary Steam Flow Study (Ex. 36), at S-0082289 - S-0082291, S-0082297; February 27, 1991 Memo to Sam Holloway (Ex. 37), at EKPC_BV3229; Sept. 30, 1991 Memo to Hubert Smith (Ex. 38); March 1, 1993 Memo to Richard Kieda (Ex. 39), at EKPC_ABB0001367, 1369; EKPC Responses to First Set of Requests for Admissions (Ex. 6), Nos. 80, 81, 82; Declaration of Yan Lachowicz (Ex. 40); Declaration of Stephen E. Pieschl (Ex. 41).

43. EKPC subsequently requested a more formal "uprating study" which was issued in August 1993. The 1993 Uprating Study concluded that Spurlock Unit 2 could be uprated to produce up to 4,000,000 pounds per hour of steam. August 19, 1993 Uprating Study (Ex. 42);EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 83.

44. The August 1993 Uprating Study was based in part on an expected fuel analysis provided by EKPC that was used to predict performance of the Spurlock Unit 2 boiler at uprated conditions. The Uprating Study predicted that producing 4,000,000 pounds per hour of steam would require 426,000 pounds of coal per hour with a heat input value of 12,531 BTU per pound. August 19, 1993 Uprating Study (Ex. 42), page 5-7 and App. A-11. The boiler heat input rate

required to produce this much steam using such coal is 426,200 pounds of coal times 12,531 BTU per pound equals 5,340,712,200 per hour, or approximately 5340 mmBTU per hour.

45. ABB-Combustion Engineering referred to the August 1993 Uprating Study as a "continuing phased evaluation of the potential for Spurlock Generating Station to be utilized as the host steam supply and maintain original steam flow to the turbine generator" and as a "continuation" of the preliminary analysis reported in the March 1992 Auxiliary Steam Flow Study. May 17, 1993 Memo to Richard Kieda (Ex. 43), ay EKPC_ABB0001330; August 4, 1993 Modeling Files (Ex. 44), at EKPC_ABB0000027; Declaration of Yan Lachowicz (Ex. 40).

46. Additional modeling performed by ABB-Combustion Engineering in support of the August 1993 Uprating Study indicated a total heat input requirement of 5,337 mmBTU per hour in order to generate 4,000,000 pounds per hour of steam while extracting steam for Inland. August 4, 1993 Modeling Files (Ex. 44), at EKPC_ABB0000027, 33; Declaration of Yan Lachowicz (Ex. 40).

47. EKPC independently calculated that a heat input of approximately 5,354.25 mmBTU per hour is required to produce 4,000,000 pounds per hour of steam at Spurlock Unit 2. H.L. Spurlock Unit Ratings (Ex. 45).

G. EKPC's Attempts to Change the Heat Input Limit in its Operating Permit.

48. On December 15, 1993, EKPC wrote to KDAQ concerning the Inland Steam Supply Project. EKPC stated that supplying steam to Inland could cause Spurlock Unit 2 to exceed the permitted 4,850 mmBTU per hour heat input rate contained in its operating permit, and requested that the permitted heat input be increased to 5,355 mmBTU per hour. December 15, 1993 Letter from Robert Hughes to John Hornback (Ex. 46).

from the reboilers to Inland and to return condensed water to the reboilers. EKPC Feb. 25, 2005 Responses to Interrogatories (Ex. 5), Pages 18, 59-69.

56. The new reboilers are 41 feet long, 10 feet high, and weigh approximately 90,800 pounds. The new reboiler superheater is 32 feet long, 6 feet high, and weighs 12,500 pounds. The new treated water storage tank is 37 feet in diameter, 35 feet tall, and holds 250,000 gallons. The new reboiler makeup water pumps weigh 2,425 pounds, the new reboiler feed pumps weigh 3,240 pounds, and the new makeup water pumps weigh 9,455 pounds. The auxiliary deaerator is 16.5 feet high, 19 feet long, 9 feet wide, and weighs 14,800 pounds. The reboiler preheater is 36 feet long. The drain tanks are 12 feet long and weigh 12,000 pounds. EKPC Feb. 25, 2005 Responses to Interrogatories (Ex. 5), Pages 64-67.

57. As part of the Inland Steam Supply Project, EKPC tapped into the Spurlock Unit 2 boiler feedwater system, on the high pressure side of the existing boiler feedwater pumps. This change was necessary in order to supply feedwater to the new attemperating system for controlling the temperature of the steam sent from Unit 2 to the reboiler supply system. EKPC Responses to First Set of Requests for Admissions (Ex. 6), No. 76; Dep. of Samuel Holloway (June 3, 2005), at 33, 133-37 (Ex. 53).

58. EKPC made changes to the high pressure feedwater system at Spurlock Unit 2 as a result of the steam supply project. Dep. of Kenneth Weiss (November 15, 2005) (Ex. 16), at 119.

59. According to EKPC expert Kenneth N. Weiss, the high pressure feedwater system is within the confines of the boiler. Dep. of Kenneth Weiss (November 15, 2005) (Ex. 16), at 125; Nov. 25, 1986 Memo from J. Rasnic (Ex. 54), at EPA3GEN061714, 61726.

60. The August 1993 Uprating study had indicated that in order to uprate the Spurlock Unit 2 boiler to 4,000,000 pounds per hour steam, EKPC also needed to increase the boiler safety valve relieving capacities in order to comply with boiler code requirements. Operation at uprated conditions required EKPC to increase the safety valves settings in order to comply with this code requirement. August 1993 Uprating Study (Ex. 42), at 3-1, 5-4 to 5-5; January 13, 1994 Letter to Sam Holloway from Factory Mutual Engineering (Ex. 55); Dep. of Samuel Holloway (June 3, 2005) (Ex. 53), at 156-158; Dep. of Kenneth Weiss (November 15, 2005) (Ex. 16), at 118, 119.

61. The Inland Steam Supply Project required the involvement of many EKPC business divisions, including the Construction Division, the Production Engineering Division, the Member Services Business Unit, Spurlock Plant Management, and EKPC Environmental Affairs. The implementation of the steam supply project was managed by the Director of EKPC's Construction Division at the specific request of EKPC's Chief Executive Officer. Other responsibilities of the Construction Division have included building new power plants on the EKPC system. 30(b)(6) Dep. of Gary Crawford (March 31, 2005) (Ex. 56), at 10-13, 207-09; EKPC Feb. 25, 2005 Responses to Interrogatories (Ex. 5), Page 131.

62. Parts for the Inland Steam Supply Project were procured in 1991, with installation occurring in stages from 1991 to the Fall of 1992. The initial tie-in to Unit 2 occurred following an outage that lasted from April to July 1992. EKPC Feb. 25, 2005 Responses to Interrogatories (Ex. 5), Page 22, 69-70, 73, 76.

63. The construction and engineering of the Inland Steam Supply Project was performed by outside contractors and required the use of heavy equipment such as cranes. The project involved almost 20 separate construction and related contracts. EKPC Feb. 25, 2005 Responses

72. The increased revenue generated from the Inland Steam Supply Project contributed to EKPC losing its tax exempt status for the 1993 tax year. January 20, 1997 Letter to Joseph Tomlinson (Ex. 68), at 4SH_0002359.

73. EKPC reported the following annual boiler maintenance expenses to the Federal Energy Regulatory Commission (FERC) for the entire Spurlock Plant (not individual Spurlock Units):

Year	Reported Amount	Source
1991	$ 10,295,167	FERC Form 1, EKPC (1991), at C-0086762-63 (Ex. 63).
1992	$ 9,060, 180	FERC Form 1, EKPC (1992), at C-0087094-95 (Ex. 64).
1993	$7,463,309	FERC Form 1, EKPC (1993), at C-0087265-66 (Ex. 65).
1994	$8,666,963	FERC Form 1, EKPC (1994), at C-0087622-23 (Ex. 66).

74. EKPC reported in 1992 that "installed capacity" at the Spurlock Station cost $592/kW. FERC Form 1, EKPC (1992), at C-0087094-95 (Ex. 64).

STANDARD OF REVIEW FOR SUMMARY JUDGMENT

Summary judgment is proper under Rule 56 where the court finds that "there is no genuine issue as to any material fact and that the moving party is entitled to a judgment as a matter of law." *Celotex Corp. v. Catrett*, 477 U.S. 317, 322 (1986). Although evidence must be viewed in the light most favorable to the non-moving party, *Adickes v. S.H. Kress & Co.*, 398 U.S. 144, 158-59 (1970), the non-moving party must go beyond pleadings and "present affirmative evidence in order to defeat a properly supported motion for summary judgment." *Anderson v. Liberty Lobby Inc.*, 477 U.S. 242, 257 (1986); *see also Matsushita Elec. Indus. Co. v. Zenith Radio Corp.*, 475 U.S. 574, 586 (1986). EKPC must adduce more than a scintilla of evidence to survive, and has an affirmative duty to direct the Court's attention to specific portions of the record upon which it relies to create a genuine issue of material fact. *Street v. J.C. Bradford & Co.*, 886 F.2d 1472, 1479 (6th Cir. 1989). EKPC has the burden of establishing the applicability of the routine maintenance exclusion. *Ohio Edison*, 276 F. Supp. 2d at 856. Thus, if EKPC fails to a make a sufficient showing on an essential element of this defense, Plaintiff is entitled to judgment as a matter of law because "a complete failure of proof concerning an essential element of the [nonmovant's] case necessarily renders all other facts immaterial." *Celotex*, 477 U.S. at 323; *see Isle Royale Boaters Ass'n v. Norton*, 154 F. Supp. 2d 1098, 1111 (W.D. Mich. 2001) ("[a] moving party who does not have the burden of proof at trial may properly support a motion for summary judgment by showing the court that there is no evidence to support the non-moving party's case").

ARGUMENT

I. The Inland Steam Supply Project Constituted A "Physical Change" Because the Project Was Not Routine Maintenance, Repair, or Replacement.

Even though EKPC asserted in its Answer that the Inland Steam Supply Project was "routine maintenance, repair and replacement," it apparently now concedes that it was not. Neither Sam Holloway, the Spurlock plant manager, nor Jerry Golden, EKPC's retained boiler expert, claim that the steam supply project to Inland qualifies as routine maintenance repair, and replacement.[8] In fact, EKPC has produced no evidence that the Spurlock project was routine maintenance, repair and replacement. Because EKPC has failed to provide any evidence that the

[8] *See* SOF ¶ 66 (Statement by Samuel Holloway that "Well, that's the only time we did it. I don't suppose you could call that routine"). Mr Golden does not address the Inland Steam Supply Project. Expert Report of Jerry L. Golden, *United States v. East Kentucky Power Cooperative*, August 15, 2005 (Ex. 69). In contrast, he claims that both of the other two projects at issue in this case, the upgrades at Dale Unit 3 and Dale Unit 4 are routine maintenance.

Inland Steam Supply Project is routine maintenance, the Government is entitled to summary judgment even absent the discussion below. *See Isle Royale Boaters Ass'n*, 154 F. Supp.2d at 1111 (W.D. Mich. 2001) ("a moving party who does not have the burden of proof at trial may properly support a motion for summary judgment by showing the court that there is no evidence to support the non-moving party's case").

Even if EKPC did not waive its routine maintenance defense, the evidence is undisputed that under the PSD regulations applicable to EKPC's conduct, the Inland Steam Supply project does not qualify as routine maintenance, repair or replacement.[9]

There is no dispute that EKPC made extensive, costly physical changes in connection with its steam supply project without obtaining permits or installing appropriate pollution control devices. As discussed below, EKPC's own documents and the testimony of its employees show that the steam supply project does not qualify for the exclusion.

In the late 1980s and early 1990s, EKPC planned and implemented a construction project designed to allow Spurlock Unit 2 to generate additional steam, and to supply that additional steam to the Inland Container Corporation. The Inland Steam Supply Project ended up costing more than $20 million, and included, *inter alia*, the construction of new reboilers and a main steam supply system, changes to the existing boiler feedwater system, the installation of new condensate, water treatment, and makeup water systems, and the uprating of the boiler to a new and higher steam production capacity that was higher than the boiler had been previously

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[9] As with the Dale Unit 3 project addressed in the Government's Third Motion for Summary Judgment, EPA analyzed and applied the "routine maintenance, repair or replacement" exclusion by using a common sense multi-factor test that assesses the nature and extent; purpose; frequency; and cost of the proposed work. *See* Clay Memo, at 3-6.

permitted to operate. SOF ¶¶ 24, 53, 55, 57, 58, 59, 60, 70. As a direct result of this capital improvement work, EKPC was able both to generate more steam and to profitably sell that additional steam to Inland. Applying the factors set forth by EPA and upheld by the Seventh Circuit in *WEPCo*, the facts established by EKPC's own testimony and documents show that EKPC cannot establish that the Inland Steam Supply Project constituted routine maintenance, repair or replacement.

A. Nature and Extent

The construction work that EKPC performed to enable it to sell process steam to Inland was not even "maintenance, repair, or replacement" work, much less "routine maintenance, repair, or replacement." The work involved building an entirely new process steam line to the neighboring Inland Container facility, plus *the addition* of new high pressure and process steam systems, a new pumping station at the Ohio River to supply cooling tower makeup water for the station, the addition of reboilers, a reboiler superheater, pressure reducing desuperheating control valves, treated water storage tank, makeup water pumps, auxiliary deaerator, blowdown cooler, reboiler preheaters, reboiler feed pumps, drain tanks, and a reverse osmosis system. This project was not maintenance, it was not repair, and it was not replacement. Rather, it was the *construction* and *addition* of entirely new components and systems that did not exist before. SOF ¶¶ 55-56.

In addition, the project involved physical changes to the Spurlock Unit 2 boiler. These included changes to the boiler's high-pressure feedwater system, in order to allow for temperature control of the steam sent from Unit 2 to the reboiler system. SOF ¶¶ 57-58. As admitted by EKPC's expert, Kenneth N. Weiss, the high pressure feedwater system is within the confines of the boiler, and EKPC made changes to the Unit 2 high pressure feedwater system as part of the Spurlock process steam project. SOF ¶¶ 58-59.

The project also required another subtle but significant change to the Spurlock Unit 2 boiler. In order to comply with the boiler code, EKPC had to change the Unit 2 boiler safety valve settings in connection with uprating the boiler to a larger steam production capacity. SOF ¶ 60. By uprating the Unit 2 boiler from a maximum continuous rating of 3,800,000 pounds per hour of steam to 4,000,000 pounds per hour of steam, EKPC was able to supply the maximum amount of expected steam to Inland (approximately 300,000 pounds per hour of steam) while still supplying the Unit 2 turbine with 3,650,000 pounds per hour of steam. SOF ¶¶ 42, 43. This increased steam production was expected to require a correspondingly greater heat input rate. SOF ¶¶ 39, 44, 46-47.

Other evidence of the non-routine nature and extent of the Spurlock project includes the following: EKPC began planning the work for the steam supply project in 1989, and commissioned multiple detailed engineering studies. SOF ¶¶ 34-38. The project involved almost 20 separate contracts and required the work of numerous contractors, including the original boiler manufacturer. SOF ¶¶ 38, 63. The project involved installation of very large pieces of equipment. For example, the two new reboilers were 41 feet long, 10 feet high, and weighed approximately 90,800 pounds. SOF ¶ 56. Because it was a new construction project, it was managed by EKPC's Construction Division Director, whose other responsibilities included building new power plants on the EKPC system. SOF ¶ 61. The work also had to be approved by the EKPC Board of Directors, and required outside financing. SOF ¶¶ 35, 68-70. As a result of the project, EKPC significantly increased its operating revenue – so much so that it lost its tax exempt status for tax year 1993. SOF ¶¶ 71-72.

Moreover, like the Dale Unit 3 project discussed in the Government's Third Summary Judgment brief, the costs of the Inland Steam Supply Project were also capitalized. SOF ¶ 70, which further indicates the non-routine nature of this project.[10]

B. Purpose

The sole purpose of the Spurlock project was to increase the steam production and heat input capacity of Spurlock Unit 2 to levels above those at which it had been previously permitted, and to allow EKPC to do something it had never done before – sell process steam to an industrial customer. SOF ¶¶ 65-66. The purpose of this project was certainly not to "maintain the plant in its present condition." Clay Memo (Ex. 2), at 4. As stated earlier, it was not even maintenance, much less *routine* maintenance, repair and replacement.

C. Frequency

This was the first and only time EKPC has ever constructed a process steam supply line for an outside customer at any of its plants, let alone the Spurlock plant. SOF ¶ 66. *See* Clay Memo (Ex. 2), at 5 (project is infrequent when it occurs once or twice during the life of typical units); *Ohio Edison*, 276 F. Supp. 2d at 861. A project to supply process steam to an off-site facility is not something that is performed frequently at typical units in the electric utility industry. Rather, this type of project is a once-in a lifetime (if ever) project that fundamentally changes the unit at issue.

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[10] For a more detailed discussion of the significance of capitalization, *see* United States' Memorandum in Support of its Third Motion for Summary Judgment, p. 22.

D. Cost

The cost of the Inland Steam Supply Project exceeded $20 million. SOF ¶ 70. As in the *WEPCo* case, this expenditure is large on both a relative and an absolute basis. This cost alone is twice the boiler maintenance expenses for any given year for the entire Spurlock plant in the years 1991 through 1994. SOF ¶ 73. East Kentucky treated the costs of the steam supply project as capital expenditures, sought to finance the entire amount of expenditures, and plans to recoup a portion of the expenses through a 20-year contract with Inland. SOF ¶ 70.

Moreover, because the purpose of this project was solely to produce additional steam for sale off-site, it is fair to compute the relative cost based on the cost of that steam alone. Because the process steam sold to Inland is the equivalent of 29 MW, the relative cost is approximately $690/kilowatt. SOF ¶ 67. This amount is more than what EKPC itself reported was the cost of the entire "installed capacity" at the Spurlock Station in 1992. SOF ¶ 74.[11]

In sum, EKPC's own documents and testimony establish that the Inland Steam Supply Project described above was not maintenance, repair or replacement, much less routine maintenance, repair and replacement.

II. EKPC Changed the Method of Operation of the Spurlock Unit 2 Boiler.

Not only did EKPC physically change Spurlock Unit 2 as a result of the Inland Steam Supply Project, but it also changed its method of operation. Thus, even aside from EKPC's physical changes made at Spurlock Unit 2, the Court should find that EKPC "changed" Spurlock

[11] As with the Dale Unit 3 project, the cost of the Spurlock project was higher on a relative scale than all the capital and maintenance costs for all five units at WEPCO's Port Washington facility, which EKPC expert, Jerry Golden admits can "be used for guidance as to what should be considered a routine expenditure on a $/kW basis." *See* United States' Memorandum in Support of its Third Motion for Summary Judgment, p. 24-25.

Unit 2 for PSD purposes. This is because the PSD regulations specifically provide that operating a source, such as Spurlock Unit 2, in a manner that is inconsistent with a prior permit application is considered *by definition* to be a "change in the method of operation."[12]

The applicable PSD regulations governing the production rate/hours of operation exclusions state in material part:

> A physical change or change in the method of operation shall not include:
> ***
> 5. An increase in the hours of operation or in the production rate, *unless the change would be prohibited after January 6, 1975 pursuant to 40 CFR 52.21 . . . or under 401 KAR 50:035. . . .*

401 Ky. Admin. Reg. 51:017 Section 1(2)(b) (1992) (Appendix C). By definition, then, the regulations define a "change in the method of operation" as *including* an increase in the hours of operation or in the production rates that *would be* prohibited by 40 C.F.R. § 52.21 or 401 Ky. Admin. Reg. 50:035. The applicable regulations set forth at 40 C.F.R. § 52.21, in turn, prohibit the owner or operator of a source that originally obtained PSD approval under EPA's regulations from operating that source "not in accordance with the application submitted pursuant to this section or with the terms of any approval to construct." 40 C.F.R. § 52.21(r)(1). These EPA regulations at 40 C.F.R. § 52.21 were explicitly retained in the Kentucky SIP for purposes of enforcement against sources which obtained PSD permits directly from EPA prior to approval of Kentucky's PSD regulations. *See* 54 Fed. Reg. at 36309 (Appendix D). EKPC applied for and obtained a PSD permit for Spurlock Unit 2 from EPA under these regulations. SOF ¶¶ 6-8.

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[12] This argument about the change in the method of operation of Spurlock Unit 2 is not based on its failure to comply with a relatively trivial provision of its permit application, which in turn triggers the requirement that the source owner must comply with PSD. Rather, EKPC's permit application included specific information on the rated *capacity* of the unit, and it is EKPC's actions to uprate its boiler and exceed that capacity that is the basis for PSD applicability.

The applicable state construction and operation regulations set forth at 401 Ky. Admin. Reg. 50:035 similarly prohibit any operation "not in accordance with the application submitted pursuant to this regulation." 401 Ky. Admin. Reg. 50:035, Section 7(1) (1988) (Appendix E); *see also id.* at Section 1(2)(a) (prohibiting operation unless "a permit to so operate" has been issued), Section 5(1) ("Permits issued hereunder shall be subject to such terms and conditions set forth and embodied in the permit as the cabinet shall deem necessary to ensure compliance with its standards."). EKPC applied for and obtained its 1980 state operating permit under 401 Ky. Admin. Reg. 50:035. SOF ¶ 22.

Thus, under the plain language of the applicable production rate/hours of operation exclusion set forth at 401 Ky. Admin. Reg. 51:017 Section 1(2)(b), operation not in accordance with a PSD application or authority to construct (as required by 40 C.F.R. § 52.21(r)(1)) or operation not in accordance with a state operating permit application or permit (as required by 401 Ky. Admin. Reg. 50:035) constitutes, by definition, a change in the method of operation of a source. In other words, the plain language of the exclusion clearly defines operation not in accordance with a previously submitted PSD application or PSD permit, or state operating permit application or permit, as a regulatory "change in the method of operation."

In this case, there is no question that the expected operation of the boiler at Spurlock Unit 2 was "not in accordance with the application" for PSD review submitted by EKPC in 1976, or with the authority to construct that was issued based on that application. There is similarly no question that EKPC's expected operation of the Spurlock Unit 2 boiler was "not in accordance with the application" for a state operating permit it submitted to the state under 401 Ky. Admin. Reg. 50:035, and with the operating permit that was issued for the unit.

EKPC's PSD application, submitted in March of 1976, included an Air Pollutant Emissions Report that indicated that Spurlock Unit 2 had a rated capacity of 4,850 mmBTU per hour, with a short-term peak heat input capacity of 5,120 mmBTU per hour. SOF ¶¶ 8-10. EKPC's state operating permit application, submitted in May 1982, simply listed the rated capacity of Spurlock Unit 2 as 4,850 mmBTU per hour, consistent with the state's modeling of the unit for purposes of demonstrating compliance with the NAAQS. SOF ¶¶ 19-20, 22. EKPC's subsequent operating permit for Spurlock Unit 2, issued in November 1982, required as an explicit "condition" of operation that the unit be operated at a "maximum heat input" of 4850 mmBTU/hour. SOF ¶¶23-24. The permit also specifically stated that "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 of Air Pollution Control." SOF ¶ 24.

The undisputed facts show that EKPC expected the Inland Steam Supply Project to cause the boiler at Spurlock Unit 2 to operate at heat input rates higher than the operating capacity of 4,850 mmBTU per hour, and even the short-term peak capacity of 5,120 mmBTU per hour identified in its PSD application. SOF ¶¶ 39, 40, 42-44, 46, 47. First, EKPC admits that engineering studies it procured indicated that the Inland Steam Supply Project could result in operation at 5,197 mmBTU per hour, even at the old maximum continuous rating of 3,800,000 pounds per hour of steam. SOF ¶ 40. Second, when EKPC on its own and without state approval uprated the Spurlock Unit 2 boiler to 4,000,000 pounds per hour of steam, the required heat input was expected to be even greater – more than 5,300 mmBTU per hour. SOF ¶¶ 44, 46, 47.

Not only do the undisputed facts show that EKPC expected as a result of the Inland Steam Supply Project to operate at heat input capacities greater than those specified in its original permit applications, EKPC's course of conduct with the state regulatory agency supports an overwhelming inference to the same effect. EKPC's engineering studies related to the Inland Steam Supply Project evaluated whether Spurlock Unit 2 could be uprated so that the unit could meet its full electricity demands while still supplying an additional amount of steam to Inland. SOF ¶¶ 42-45. Those studies indicated that at anticipated demands from Inland, the total heat input required could be as high as 5340 mmBTU per hour. SOF ¶¶ 44-46. Just months after receiving the results of a formal Uprating Study, EKPC asked KDAQ to increase the heat input capacity in EKPC's permit to 5,355 mmBTU per hour. SOF ¶ 48. There is no reason for EKPC to have requested an increase in permitted heat input unless it thought it might in fact operate at the higher heat input, and thus the request itself is an admission. But there is more.

Only weeks after receiving the request from EKPC to increase the permitted heat input for Spurlock Unit 2, KDAQ informed EKPC that the requested uprating would only be allowed if EKPC provided proof that operating at that level would not trigger PSD as a result of increased emissions. SOF ¶ 49. EKPC did not comply with the KDAQ's clear and unambiguous instructions to submit emissions calculations. In fact, EKPC remained silent. Finally, in December 1994, KDAQ sent a follow-up letter to EKPC asking about the status of the requested emissions submission. SOF ¶ 50. Only then did EKPC respond, saying that it was reevaluating the future planned use of the unit and "will evaluate the need to continue this process at a later date." SOF ¶ 51. A reasonable regulator would understand this letter to be saying that EKPC had decided that it did not need or intend to uprate its boiler and operate at a heat input greater than authorized in its permit. The reasonable regulator would be wrong. As of January 13, 1994 EKPC had already instructed plant operators that they were free to exceed the old steam flow limit of 3,800,000 pounds per hour and that they could henceforth operate the boiler at 4,000,000 pounds per hour of steam. SOF ¶ 53. Unless EKPC has changed the laws of physics and discovered something as yet unrevealed in discovery, increasing the amount of steam generated of necessity requires more heat input. And EKPC well knew that the amount of heat needed to supply steam at 4,000,000 pounds per hour would greatly exceed its permitted limit of 4850 mmBTU per hour. SOF ¶¶ 44-46.

Accordingly, there can be no dispute that EKPC's decision to increase the heat input and steam production rate of Spurlock Unit 2 was itself a "change in the method of operation" as defined by the applicable PSD regulations because it was not consistent with the heat input information contained in EKPC's PSD application, as required by 40 C.F.R. § 52.21(r)(1), and because it was not consistent with EKPC's operating permit and permit application, as required by 401 Ky. Admin. Reg. 50:035. See 401 Ky. Admin. Reg. 51:017 Section 1(2)(b)5 (1992) (Appendix C).

While not necessary to the determination of this motion given the plain language of the regulations, it is also worth noting why, as a policy matter, it makes sense to treat EKPC's expected increase in heat input rate as a change in method of operation. As noted above, the air quality modeling and compliance determinations performed by EPA and KDAQ when EKPC first sought approval to construct Spurlock Unit 2 were all based on the heat input rate information provided by EKPC in its applications. SOF ¶¶ 12, 13, 19, 20. By increasing its heat input over the levels identified in its applications, EKPC has fundamentally changed the assumptions upon which approval to construct the unit was based. If air quality modeling were to be redone using a higher heat input capacity and the same coal sulfur content that was identified in EKPC's permit application and subsequent permits, the unit would have been modeled at a higher emissions rate because increasing the heat input rate is directly proportional to the amount of emissions from a unit. Dep. of Kenneth Weiss (November 15, 2005) (Ex. 16), at 26-28; *cf. United States v. Chrysler Corp.*, 437 F. Supp. 94, 97 (D.D.C. 1977) (it is a violation of the Clean Air Act for an automobile manufacturer to install parts that were different from those specified on its application for certificate of conformity), *aff'd*, *United States v. Chrysler Corp.*, 591 F.2d 958, 961 (D.C. Cir. 1979).

Moreover, the state of Kentucky's Emissions Inventory System has consistently identified the rated capacity of Spurlock Unit 2 as 4,850 mmBTU per hour, and other sources seeking their own PSD approval following construction of Spurlock Unit 2, have not modeled the Spurlock unit based on its uprated capacity. SOF ¶¶ 25, 26, 28, 29. In a case involving an analogous exclusion from the definition of physical or operational "change" for decisions to burn certain types of alternative fuels, the Ninth Circuit held that reliance by subsequent PSD applicants on previously modeled parameters was a strong policy reason for requiring PSD review of a change that would affect prior modeling analyses. *See Hawaiian Elec. Co. v. EPA*, 723 F.2d 1440, 1448-49 (9th Cir. 1984) (holding that PSD review should be required for a change in operation that was inconsistent with PSD modeling performed by subsequent PSD permit applicants); *see also* 45 Fed. Reg. at 52704 ("any change in hours or rate of operation that would disturb a prior assessment of a source's environmental impact should have to undergo scrutiny") (Appendix A).

In sum, there can be no dispute that EKPC changed the method of operation of Spurlock Unit 2 under the plain language of the applicable PSD regulations. EKPC expected to operate Spurlock Unit 2 boiler at heat input levels greater than any levels identified in its PSD permit application or state operating permit application, and such operation is explicitly defined by the PSD regulations to be a "change in the method of operation." Accordingly, the Government is entitled to summary judgment that EKPC change the method of operation of Spurlock Unit 2.

CONCLUSION

The Court should conclude as a matter of law that the Inland Steam Supply Project at Spurlock Unit 2 was a physical change that was not "routine maintenance, repair, and replacement," and that this project also involved a change in the method of operation of Spurlock Unit 2.

DATED: January 17, 2006.

Respectfully Submitted,

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Response to East Kentucky Power's Comments
(3/13/98 Letter)

Comment (1): All the permit conditions that represent CAM should be removed from the permit. CAM functions are not to be applied to these permits as is identified in the CAM regulations.

Response to (1): The Division agrees with the comment that the source is not subject to Compliance Assurance Monitoring (CAM) procedures since the application for the facility was deemed administratively complete by the Division prior to promulgation of CAM procedures and the permittee is not required to implement the CAM procedures until the permit undergoes revision or renewal. However, the Division finds this comment on CAM applicability for this source irrelevant since the permit does not include any requirements developed based on CAM rule. The Division is not implementing CAM but is implementing periodic monitoring required by existing regulations.

Comment (2): All particulate testing should be on a once per permit basis. Any additional testing should be based on a need be basis:

Response to (2): EKP did not give a proposed plan that would satisfy the periodic monitoring requirements to assure compliance with the particulate emission standard; therefore, the permitting authority, the Division, must impose necessary periodic monitoring requirements pursuant to Regulation 401 KAR 50:035, Section 7(1)(c), Section 504 of the Clean Air Act, and 57 FR 32278. The requirements are dependent upon information obtained through stack testing which the Division may require at any time pursuant to Regulation 401 KAR 50:045, Performance tests, Section 1.

Comment (3): All records required by this permit should be defined as those records currently being maintained for operational reasons. During the development of this regulatory package, the Division stated that the permit would not place any new requirements on a facility.

Response to (3): In your comments you did not define what records you are talking about. However, the Division has not imposed any new record keeping requirements except those which are required by the Title V permit requirements.

Comment (4): The use of COM date as an indicator of particulate matter mass emission should be deleted from all the permits. The Division nor EPA has shown any relationship between the two parameters.

Response to (4): The Division belives that compliance with the particulate matter emission standards is best indicted by use of a COM. Since you have not proposed any mutually acceptable alternatives to this method, the COM requirment has not been deleted from this permit.

EXHIBIT M

EKPC R16 - 000525
Confidential Business Information

Comment (Two fly ash silos): These should be deleted from the permit- they were not constructed as planned.

Response to (Two fly ash silos): The Division agrees with your comments, and the two fly ash silos have been deleted from your final permit.

Comment (Source address): The current address for the facility has been changed by the U.S. Postal Service from Route 8 to 1301 West Second Street.

Response to (Source address): Your source address has been changed from Route 8 to 1301 West Second Street on your final permit and all the Division files have been updated.

Comment (Maximum continuous rating for Emission Unit 02): The maximum continuous rating should be increased to 5600 mmBTU/hr.

Response to (Maximum continuous rating for Emission Unit 02):As stated in the Division for Air Quality letter dated February 3, 1994, this rating cannot be increased until the demonstration of applicability or non-applicability of Regulation 401 KAR 51:017, Prevention of significant deterioration of air quality.

Comment (Emissions Unit 04): It is assumed that each stack refers to baghouse since there are no stacks present. Visual emissions should be observed only without the use of Reference Method 9.

Response to (Emissions Unit 04): Regulation 60:250 requires visual emissions to be observed only by Reference Method 9.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Memorandum in Support of the United States' Fourth Motion for Summary Judgment was served on January 17, 2006, on the persons listed below:

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